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December 4, 2020

Ms. Kimberly A. Campbell
Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

RE: Duke Energy Progress LLC's Post-Hearing Brief Supporting Recovery Of and Return On Coal Ash Costs
Docket No. E-2, Sub 1219
Docket No. E-2, Sub 1193

Dear Ms. Campbell:

Enclosed for electronic filing is Duke Energy Progress LLC's Post-Hearing Brief Supporting Recovery Of and Return On Coal Ash Costs.

If you have any questions, please let me know.

Sincerely,

/s/ Camal O. Robinson
Camal O. Robinson

Enclosures

cc: Parties of Record

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1219
DOCKET NO. E-2, SUB 1193

DOCKET NO. E-2, SUB 1219 In the Matter of Application of Duke Energy Progress, LLC For Adjustment of Rates and Charges Applicable to Electric Service in North Carolina DOCKET NO E-2, SUB 1193 In the Matter of Application by Duke Energy Progress, LLC, for an Accounting Order to Defer Incremental Storm Damage Expenses Incurred as a Result of Hurricanes Florence and Michael and Winter Storm Diego	)	**DEP'S POST-HEARING BRIEF SUPPORTING RECOVERY OF AND RETURN ON COAL ASH COSTS**

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BRIEF SUPPORTING RECOVERY OF AND RETURN ON COAL ASH COSTS

Duke Energy Progress, LLC (DEP or the Company) hereby submits its Post-Hearing Brief Supporting Recovery of and Return on Coal Ash Costs (Brief).

INTRODUCTION

DEP seeks in this rate case a total of approximately $440 million (on a North Carolina retail basis) in coal ash (CCR) basin closure costs, consisting of (a) actual costs of closure activities performed during the period from September 1, 2017 through February 29, 2020, all of which were incurred as a result of changes in the law with which the Company must comply, and all of which have been deferred by order of the Commission, and (b) financing costs incurred during the deferral period through August 2020. Every dollar of these costs (CCR Costs) was advanced by the Company's investors, both debt and equity, pursuant to the "spend/defer/recover" model – a model that DEP told the Commission it would be following with respect to coal ash expenditures almost five years ago, and a model that the Commission required the Company to follow in its previous rate case.[1]

As a rate mitigation measure, DEP proposes to bring these costs into rates over a five-year amortization period beginning with the date new rates go into effect. DEP proposes further that it earn a return on the unamortized balance, at its authorized weighted average cost of capital. Should the return be disallowed, the net result would be the equivalent of a forced interest-free loan by the Company to its customers, an outcome manifestly unfair to the Company and its investors. No

[1] Docket No. E-2, Sub 1142, which was decided by the Commission's February 23, 2018 Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase (2018 DEP Rate Order, or, simply, 2018 Order). The CCR Costs sought for recovery are net of the amount that the Company had been collecting for coal ash basin closure through depreciation expense as allowed by the Commission in a previous DEP rate case, Docket No. E-2, Sub 1023.

provision of the General Statutes, no decision of the North Carolina Supreme Court or the Court of Appeals, and no decision of the Commission permits the Commission to force the Company to make an interest-free loan to its customers – and requiring the Company to do so would be an unconstitutional "taking" of property.[2]

The relief requested by the Company in this case is precisely the rate treatment afforded by the Commission to the Company in its last rate case. DEP hereby submits this Brief, focusing on both (1) recovery "of" the coal ash costs the Company seeks in the current case (i.e., approximately $440 million), along with (2) a return "on" those costs as they are brought into rates during the amortization period. Recovery both "of" and "on" the incurred costs is warranted under the facts and the law, for the reasons set forth herein and already articulated by the Commission in its 2018 Order.[3]

BACKGROUND

The Company's prior case was decided on February 23, 2018, not quite three years ago. Every major issue raised by Intervenors in the current case was raised by Intervenors in the prior case, and those fully litigated issues were decided by the Commission in its 2018 Order:

- The Company's "historical"[4] coal ash management practices, including their conformance to industry standards (2018 Order, at 142), which put to

[2] The interest-free nature of the loan means that the Company's ability to earn its authorized return would necessarily be impaired, and impairment of its ability to earn its authorized return constitutes an unconstitutional taking of property. *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) (*Hope*); *Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923) (*Bluefield*).

[3] In accordance with the Commission's request, DEP also addresses alternative models for cost recovery in a separate brief, filed herewith.

[4] "Historical" meaning prior to the changes in law wrought by the promulgation of the Federal CCR Rule in 2015, as well as the passage by the North Carolina General Assembly of the Coal Ash Management Act (CAMA) in 2014 and amendments to CAMA in 2016.

bed Intervenors' arguments that the Company imprudently managed CCR in the pre-2014 period;

- The Company's need for regulatory certainty prior to incurring costs – which customers would be expected to pay – so as not to credibly be accused of gold-plating (2018 Order, at 183), which put to bed Intervenors' arguments that DEP should have acted "differently" – but in an undefined way – and changed its ash management practices at some earlier, but also undefined, point in time;

- The Public Staff's "equitable sharing" theory of cost disallowance, which the Commission emphatically rejected (2018 Order, at 188-89);

- The propriety and effect of the Asset Retirement Obligation (ARO) accounting employed by DEP to account for its CCR expenditures (2018 Order, at 196);[5] and

- The "spend/defer/recover" model employed by the Company in connection with its coal ash expenditures, which makes DEP entitled to receive a return on such costs during both (1) the period during which those costs were deferred, and (2) the amortization period during which the previously deferred costs are brought into rates (2018 Order, at 194-96, 206).[6]

Regarding CCR, when arrayed against the Company's last rate case and the identical issues addressed by the Commission in DEC's last rate case, the current case is simply "*déjà vu* all over again."[7]

Not only are the major issues from the prior cases regurgitated in the current case, no "new" evidence illuminating any of these issues was adduced in the current case by Intervenors. For example, in the current DEP and DEC cases, as in the prior DEP and DEC cases, in attempting to prove "imprudence" by the Company in its historical management of coal ash, Intervenors once again cherry pick and

[5] See also the Commission's June 22, 2018 Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction in Duke Energy Carolinas' (DEC) last rate case, Docket No. E-7, Sub 1146 (2018 DEC Rate Order, or, simply, DEC Order), at 284-90. These issues were explored in more depth in the E-7, Sub 1146 Docket in light of additional development of ARO accounting evidence brought forward by the Public Staff. (See id. at 283.)
[6] See also 2018 DEC Rate Order, at 288-92.
[7] Berra, *The Yogi Book* (Workman Publishing 1998), at 45.

selectively quote from the same body of historical studies (Joint Exhibits 1-13) and ignore the conclusions actually reached by the authors of those studies.

"New" evidence from DEP, in its rebuttal case, supplemented and added more detail to evidence the Company presented in the prior case, primarily as a result of Intervenors raising the same issues that the Commission had already dealt with in the prior case. For example, the testimony of Company witness Marcia Williams brought to the Commission the perspective of a former EPA regulator, who led the EPA office that produced one of the major historical studies proffered by Intervenors as "evidence" of the Company's historical imprudence, the 1988 EPA Report to Congress (1988 Report, Joint Ex. 13). Refuting Intervenors' arguments, witness Williams testified that the 1988 Report *validated* the Company's historic ash management practices. As she noted, in the 1988 Report EPA concluded that no change was necessary to then-current coal ash waste management practices, inasmuch as those practices "appear[ed] adequate for protecting human health and the environment." (Joint Ex. 13, at 7-11.) And, as witness Williams also noted, EPA in crafting its 1988 Report was well aware that then-current waste management practices included, particularly in the Southeastern United States, unlined ash ponds. She noted that the 1988 Report found that these ponds

> [R]arely included the use of liners or leachate collection and that most facilities managing CCR did not have groundwater monitoring. The report found that 80 percent of CCR was disposed on the land (i.e., in surface impoundments, landfills, or other land-based units). Of the 483 surface impoundments in use at the time, only 45 were known to be lined while 303 were unlined and the liner status of 135 were unknown. In EPA's Region IV, which includes North Carolina, only 3 of the 195 surface impoundments were lined, while 153 were unlined and the liner status of 39 were unknown.

(Tr. vol. 19, 222-23.)

In the Company's prior case and after a full trial on the merits, the Commission adjudicated these same contentions and found as a fact that "[s]ince the 1950s, standard industry practice at least in the Southeast, has been to deposit coal ash in coal ash basins." (2018 DEP Rate Order, at 142.) In DEC's prior case, the Commission found further that as the 1988 Report itself indicated "'until recently, most surface impoundments and landfills used for utility waste management have been simple unlined systems.'" (2018 DEC Rate Order, at 267.) Even as late as 2010, when EPA proposed its CCR Rule, witness Williams testified that according to EPA, 74% of existing units were unlined, and 40% of "new" (meaning constructed during the 1990s or thereafter) units were unlined. (Tr. vol. 19, 422.) The Company did not construct any coal ash basins after 1985, and all but one of its basins were unlined,[8] in accordance with standard industry practice at the time of their construction. Yet Intervenors' *déjà vu* presentation ignores these already-adjudicated facts and forces the Company to prove them all over again.

In this case as in the last one, Intervenors ask the Commission to deny cost recovery on the basis of "fault"-based concepts, like "culpability." This is yet another aspect of Intervenors' "*déjà vu* all over again" approach. The Commission is an economic regulator, a delegatee of the General Assembly, with specific duties and functions defined by statute. *State ex rel. Utils. Comm'n v. Edmisten*, 291 N.C. 451, 464 (1977) ("The Commission is a creation of the Legislature and, in fixing rates to be charged by public utilities, exercises the legislative function. It has no authority except that given to it by statute."). The Commission is not an environmental agency,

[8] The exception is the basin the Company constructed at its Sutton Plant in 1984, which is discussed in detail below. (See pp. 43-44, below.)

charged with the enforcement of the nation's or this State's environmental laws. In North Carolina, that is the Department of Environmental Quality (DEQ). Nor is it a court of general jurisdiction, endowed with the responsibility to pass on issues of tort liability or due care under the circumstances. Rather, it sits in this proceeding with a specific task: to determine just and reasonable rates that the Company may charge its customers, rates that by statutory design must be "fair both to the [utility] and to the consumer." N.C. Gen. Stat. § 62-133(a).

Cost recovery under North Carolina law is regulated by the Commission under the prudence standard. Prudently incurred costs associated with service to customers are recoverable.[9] Such costs include financing costs – the cost of money – upon prudently incurred costs funded by the Company and its investors and deferred by order of the Commission in advance of being brought into rates, especially when they are brought into rates over time as a mitigation measure to reduce the impact of increased rates upon customers. Costs that are not prudently incurred are not recoverable. There is no room in such an analysis for tort-like "fault" concepts, and those concepts have no place in cost recovery under North Carolina

[9] The requirement that costs be associated with service belies the Public Staff's argument that many different types of costs are "shared" between shareholders and customers. For example, the Public Staff points to costs of senior management in a utility holding company. (See DEC Tr. vol. 26, 121-22; the Commission has taken judicial notice of the evidence from the DEC-specific hearings referred to in this Brief.) Such costs may well be "shared" but prudence, imprudence, or even "fault" have nothing to do with the sharing. Rather, because senior management's duties are split between separate utilities – or even between regulated and unregulated entities – only a portion of them are necessary to support service by any specific utility. And, of course, costs must also be "known and measurable" (2018 DEP Rate Order, at 143.) Here, as in the Company's prior case (as in DEP's prior case, see 2018 Rate Order, at 196), no party has questioned whether CCR Costs are "known and measurable." Finally, costs must be "reasonable" in size, but in the context of this case the prudence framework captures the concept of "reasonable" – costs unreasonably large in size can hardly be said to have been prudently incurred.

law. Intervenors invite the Commission to become what it is not. The Commission should decline the invitation.

ARGUMENT

Intervenors seek to deny DEP recovery "of" CCR Costs, along with a return "on" such Costs. Each topic is addressed in this Brief – recovery "of" in Section I, and return "on" in Section II. The Company has met its burden – both the prima facie burden of production and the ultimate burden of persuasion – of showing that CCR Costs were reasonable and prudently incurred, and is therefore entitled to recovery thereof. The Company has also shown its entitlement to a return "on" those Costs, at its authorized weighted average cost of capital, during the amortization period over which the Costs are brought into rates.

I. DEP IS ENTITLED TO RECOVERY "OF" ITS COAL ASH COSTS, BECAUSE THE COSTS WERE PRUDENTLY INCURRED AND INTERVENORS' CHALLENGES TO RECOVERY FAIL

The prudence standard requires a detailed and fact intensive analysis into the challenged conduct. This analysis necessarily involves detailed inquiry into industry standards at the time decisions were made, inasmuch as conduct that conforms to the standards of the industry as a whole can hardly be deemed to be imprudent. The analysis also requires quantification of impact, inasmuch as cost disallowance requires quantification – without quantification there is no proven actual dollar amount the Commission may disallow.

Under the prudence standard, the Company is entitled to recover the entirety of its CCR Costs. DEP has shown that its expenditures were reasonable and prudent. The Public Staff advocates "imprudence" disallowances of a portion of CCR Costs. Through the testimony of witnesses Bernard Garrett and Vance Moore, the Public

Staff seeks to establish that certain expenditures made by the Company during the September 1, 2017 through February 29, 2020 time period were imprudent based on the witnesses' review and critique of the Company's activities undertaken during that time period. Witnesses Garrett and Moore thus at least assert an actual prudence challenge, although the challenge fails. This is an intensely fact-specific topic, and the Company addresses this failure in detail in its Proposed Order.

The Public Staff, the Attorney General's Office (AGO), and Sierra Club mount additional challenges to CCR cost recovery that are not based upon the prudence standard. All three Intervenors assert that recovery of CCR Costs or some portion thereof should be disallowed because the Company was purportedly at "fault" for alleged actions or omissions in the past, long before the CCR costs at issue in this case were actually incurred, and long before the changes in law that required their incurrence were enacted and promulgated. DEP has refuted these allegations and shown to the contrary that its historical coal ash management practices met or even exceeded industry standards. Further, while no Intervenor has shown such historical imprudence, even if there were any, no Intervenor has been able to quantify the impact of such conduct upon and in relation to the CCR Costs actually incurred by the Company in the September 1, 2017 through February 29, 2020 period – a period long after any alleged (but unproven) imprudence could have occurred.

Without quantification, Intervenors' challenges fail. This failure is addressed in connection with the Company's discussion of the application of the prudence framework, inasmuch as quantification of impact is an integral part of that framework. (See pp. 36-40, below.) The Public Staff's "equitable sharing" theory fails too, not only because of its inability to quantify disallowed costs, but also because it is inherently arbitrary. This too is discussed further below, both generally in connection with Intervenors' "fault" based disallowance concepts, and specifically with respect to application of the theory to the facts of this case.

A. Tort-Like Concepts of "Fault" or "Culpability" are Foreign to Cost Recovery under North Carolina Law

The principal challenge relating to the Company's past activity is the Public Staff's "equitable sharing" theory (at least, "equitable" in the eyes of the Public Staff – not "equitable" in any objective sense). This theory is by the Public Staff's own admission expressly *not* based upon the prudence framework. (See Public Staff witness Jay Lucas' testimony at Tr. vol. 15, 1444 ("I do not believe the traditional imprudence approach is feasible for most of DEP's coal ash costs."); id. at 1449 ("equitable sharing" recommendation is not based on the "imprudence standard"); id. at 1506 (Public Staff "did not conduct a prudence review" of the construction and operation of the ash basins). Rather, the Public Staff asserts that "sharing" is appropriate because of DEP's "culpability" for the incurrence of CCR Costs, although the Public Staff is unable to articulate a standard for "culpability."

"Culpability" denotes fault – a tort-like concept. Apart from Garrett & Moore's purported (and erroneous) "imprudence" disallowances, all other disallowances proposed by Intervenors similarly assert fault. Intervenors' challenge to the Company's historical coal ash management practices is based entirely on tort-like "fault" concepts. Even the discrete disallowances advocated by witnesses Lucas and AGO witness Steven Hart (for example, costs associated with DEP's obligations under the 2016 amendment to CAMA to provide permanent alternative water supplies to customers located within a half-mile of its coal ash basins) are based on "fault." Based upon pure supposition and without any knowledge of the context, witness Hart claimed the alternative water supply costs were incurred "likely [as] a result of DEP's delay in addressing groundwater impacts." (Tr. vol. 13, 545-46, 712.) Neither witness Lucas nor witness Hart evaluated the actual activities undertaken by DEP to connect customers to alternative (typically municipally-supplied) water, or the costs incurred – they simply state (ignoring the legislative requirement of the 2016 CAMA amendments) that the Company was at "fault," thereby the costs should be disallowed. But that is not the law in North Carolina.[10]

The Commission presented a detailed critique of the "fault" based and tort-like disallowance theories proposed in DEC's prior case. (2018 DEC Rate Order, at 260-65.) The Commission held that its

> [D]uty is not to determine liability to and assess damages for torts committed by management for injury to the environment or to receptors of contaminants. Environmental regulators and courts of general jurisdiction are the appropriate arbitrators of those disputes. DEC's unlined impoundments at issue operated pursuant to environmental permits as wastewater treatment facilities by DEQ or its predecessor. That agency's statutory mandate is environmental protection and would be the agency to rectify breaches of a duty of due care, if any, such as that advocated by certain Intervenors in this case. The issues before this economic regulatory tribunal is imprudence -- who should bear the remediation costs, the utility stockholders or its customers and on the basis of what justification.

[10] Denial of cost recovery by the Commission may only occur with reference to an established standard of conduct which the utility does not meet. *State ex rel. Utils. Comm'n v. Carolina Water Serv., Inc.*, 335 N.C. 493 (1994). In that case, the Commission imposed upon the utility (CWS) a 1% penalty for "inadequate service." The evidence relied upon by the Commission consisted merely of complaints of poor service made by customers at public hearings. The Supreme Court reversed. It held that the Commission's "order indicate[d] neither in what manner CWS violated the Commission's standards nor what those standards are," and that the order does not "set forth the basis upon which it determined that water quality and service which meets the requirements of the Division of Environmental Health (DEH) is inadequate." Id. at 501-02.

(Id. at 261.) Noting further that Intervenors equated lack of due care to management imprudence, the Commission stated that no party cited to it any authority "to support the theory that, in determining the recovery through utility rates, costs of environmental remediation incurred by management to comply with express requirements of environmental regulators, management decisions should be assessed against a standard of due care." (Id.) These observations are still valid, and apply with equal force to DEP in this case. So, this is yet another "*déjà vu* all over again" topic.

Just for the sake of argument, were the Commission to depart from its statutory mandate and import tort-like concepts into a rate proceeding, then it would not be permitted to merely dip a toe into the tort waters, or pick and choose which aspects of tort law to follow – it would have to adopt tort concepts wholesale. Intervenors would still lose.

A tort claim requires a plaintiff with injuries and standing to sue – no such plaintiff exists in this case. A tortfeasor must owe and have breached a duty to the claimant, and alleged breach of that duty must be measured against prevailing practices in the industry – industry standards. DEP met or exceeded all applicable industry standards. The injury must be caused by the actions or inactions of the tortfeasor. No causation exists – the CCR Costs sought for recovery were incurred in order to comply with changes in the law. No court would be permitted to hold that the Company "caused" either the EPA or the General Assembly to promulgate and enact rules and legislation.[11] In any case, the EPA and the General Assembly would stand as insurmountable intervening causes for the incurrence of CCR Costs. Stale tort claims are barred by applicable statutes of limitation and repose – in North Carolina, a ten-year statute of repose for claims generally, and even shorter periods for certain types of claims, such as professional negligence; and a three-year statute of limitation for injury to persons and property. Intervenor testimony was filed on April 13, 2020. Any claim related to conduct occurring more than three years prior to that date would be barred. That would bar any claim related to the Company's conduct in the 1980s, 1990s, 2000s, and even through the enactment of CAMA (2014) and the promulgation of the CCR Rule (2015). The doctrines of *res judicata* and collateral estoppel would apply, which would bar every single one of the Intervenors' claims and theories, given that the 2018 DEP Rate Case Order granted DEP the relief it sought in that case, rejected every single one of Intervenors' disallowance theories, and denied Intervenors any relief whatsoever. And, of course, tort claimants must prove specific damages suffered by *them* – and none of the Intervenors have done so.

The burden of proof in a tort case to show duty, breach of that duty, causation, and damage, is upon the claimant – here, the Intervenors. The claimant must prove each and every one of these elements, and failure to prove even one will result in denial and dismissal of the claim.

[11] See 2018 DEC Rate Order, at 271-72 (legislative intent in North Carolina is gleaned from the words of the statute, and even materials such as press releases or commentary "are not treated as binding authority" by the courts).

By contrast, the burden of proof in a utility rate proceeding to show that the rates to be charged are just and reasonable, and to show that the costs sought for recovery are recoverable, is on the utility. N.C. Gen. Stat. § 62-134(c). In their rush to have the Commission adopt tort-like theories of "fault" or "culpability," Intervenors evidently forget that were it to do so their burdens would multiply, and the Company's burden would shrink.

The Commission's statutory mandate is to determine just and reasonable rates the Company may charge for the provision of electric service. This is an issue of economic regulation, not "fault." In the 2018 DEC Rate Order, the Commission noted that a cost recovery challenge "has elements qualitatively and quantitatively distinct and more rigorous than a tort standard of due care" (id. at 262) – the prudence framework. It is that framework, not "culpability" or "fault" or any other tort-like concept, that controls the outcome as to which costs incurred by the Company and sought for recovery in a rate case should be recovered from customers, and which costs should be borne by the Company and its investors.

B. "Equitable Sharing" and "Culpability" are Standard-Less and Arbitrary, Have Been Repeatedly Rejected by the Commission, and Should Not Be Adopted

Intervenors' principal "fault"-based theory is advanced by the Public Staff. Slightly over three years ago, when the Public Staff filed testimony in DEP's last rate case, it unveiled its theory of "equitable sharing,"[12] whereby it proposed that a substantial portion of coal ash costs – *costs which it could not classify as having been imprudently incurred* – be shared 50/50 between DEP and its customers, based on

[12] That testimony was filed on October 20, 2017.

some (undefined) degree of DEP's "culpability" for the incurrence of those costs. It proposed the same theory, albeit with a different sharing ratio (51/49, in favor of customers) in DEC's last rate case. It proposed the same theory, with yet a different sharing ratio, in Dominion Energy North Carolina's (Dominion) last rate case – 60/40 in favor of Dominion. In each one of those cases the Public Staff asserted that adoption of the theory, and of the Public Staff's chosen sharing ratio, was within the Commission's discretion. In each one of those cases the Commission rejected the theory, indicating that the theory was arbitrary and, were it to be adopted, would expose the Commission to attack for imposing an arbitrary and capricious disallowance of costs.

In this case the Public Staff once again advances its now quite stale "equitable sharing" theory, asking the Commission to "take a fresh look" at its arguments. (Tr. vol. 15, 1501, 1513-14.) There is no need for a "fresh look" – the Public Staff's theory is today just as arbitrary as it was when the Commission rejected it in DEP's and DEC's prior cases:

> First, the concept is standard-less, and, therefore, from the Commission's view arbitrary for purposes of disallowing identifiable costs – there is no rationale that supports a substantially large 51% disallowance. The Public Staff chose a desirable equitable sharing ratio, then backed into the mechanism to achieve that level of disallowance, leaving the allocation subject to an arbitrary and capricious attack, particularly as it provides no explanation as to why the "equitable" split for DEP in the 2018 DEP Case was in its view 50-50, while the "equitable" split in this case is 51-49. As the Commission held in the 2018 DEP Case, the "Public Staff provides insufficient justification for the 50/50 [split] as opposed to 60/40 or 80/20 ...." 2018 DEP Rate Order, p. 189.

(2018 DEC Rate Order, at 273.) And in DEP's prior case the Commission indicated further, citing *Tate Terrace Realty Investors, Inc. v. Currituck Cty.*, 127 N.C. App. 212, 222-23 (1997), that a "determining principle" was missing from the Public Staff's proposal, and that in its absence "were the Commission to adopt [equitable sharing], the Commission very well could be found to be acting arbitrarily and capriciously, and subject itself to reversal." (2018 Order, at 189 (citing *Sanchez v. Town of Beaufort*, 211 N.C. App. 574, *disc. review denied*, 365 N.C. 349 (2011).)

Nothing has changed since the Commission wrote those words. The Public Staff followed the exact same methodology, described in witness Maness' testimony, as it did in the Company's last case (and in DEC's last case, and in Dominion's last case) to create the sharing arrangement. First, witness Maness removed unamortized coal ash costs from rate base, thereby eliminating any return on that unamortized balance. (Tr. vol. 15, 1565.) Next, he chose an amortization period that would result in the Public Staff's desired sharing ratio. (Id. at 1577-79.) In other words, just as it did in the Company's last case (and in DEC's last case, and in Dominion's last case), the Public Staff merely chose its desired sharing percentage, then mathematically backed into that percentage by using the amortization period as a toggle.

It is the Public Staff's choice of the sharing percentage that is arbitrary and "without a determining principle." Commissioner McKissick's request in the DEC-specific hearing of the Junis/Maness panel to provide him with "standards" for "culpability" is a request that the Public Staff provide him with this determining principle: "a standard that applies not simply to the facts of this case, but to other cases that the Commission might consider if they're going down the path of equitable sharing." (Tr. vol. 15, 1807.)[13] Despite having espoused "equitable sharing" and "culpability" for the past three years, the Public Staff is still unable to supply this determining principle, as is evident from its submission of Public Staff Late-Filed Exhibit No. 1 (PS LFE No. 1).

The prudence framework is an established standard of conduct against which the utility's actions may be judged. Commissioner McKissick's request was for the Public Staff to articulate criteria by which the Commission could *objectively*, not *subjectively*, judge a utility's conduct, and, on the basis of that objective review, determine whether the utility's conduct merited a finding that some costs sought to be recovered should instead be disallowed. According to PS LFE No. 1, "equitable sharing" and "culpability" are grounded in the Commission's discretion, granted by N.C. Gen. Stat. § 62-133(d), to consider "all other material facts of record" in setting rates that meet the statutory mandate of being just and reasonable, and fair to the utility and the consumer. (Id. at 3.) However, consideration of all other material facts "is not a grant to roam at large in an unfenced field." *State ex rel. Utils. Comm'n v. Pub. Serv. Co. of N. C.*, 257 N.C. 233, 237 (1962).

[13] On September 28, 2020, the Company filed with the consent of the Public Staff, the AGO, and Sierra Club an Amended Joint Stipulation (Amended Stipulation) regarding certain coal ash and coal ash accounting-related testimony and exhibits admitted into evidence during the DEC-specific hearings. Pursuant to the Amended Stipulation, the stipulating parties agreed that that evidence was admissible in the DEP-specific hearings, and, specifically with respect to testimony, that they recognized "that a question posed live in the [DEC] hearing to a witness in that hearing would be answered in like fashion by that same witness, tailored to [DEP], in the [DEP] hearing." (Amended Stipulation, at 3.) The parties further noted in this regard that "Public Staff witness Junis appeared in the [DEC] case, but is not appearing in the [DEP] case, and that his place in the [DEP] case is being assumed by Public Staff witness Jay Lucas. Accordingly, in this instance, the 'same' witness as Charles Junis in the [DEP] case is understood to be Public Staff witness Lucas." (Id., fn. 2.) During the course of the DEP hearing all stipulated testimony was in fact introduced into evidence and is part of the DEP Record.

Commissioner McKissick asked the Public Staff to provide the fencing – the Public Staff's response, essentially, is that there is no fencing save the Commission's (unbridled) discretion.[14] PS LFE No. 1 does not articulate *any* rules, much less rules that can be objectively and generally applied to conduct beyond the facts and circumstances of this case. Rather, PS LFE No. 1 conclusively proves that the Commission's insights and holdings from the 2018 DEC and 2018 DEP Rate Orders were exactly correct – "culpability" and "equitable sharing" are standard-less concepts without any consistent and objectively understandable rationale. To the contrary, they are merely expressions of the Public Staff's "judgment" as to how and in what ratio coal ash costs should be shared between the Company and its customers – an arbitrary and continuously fluctuating calculation of the Public Staff alone. Were the Commission to agree and adopt that calculation, it would be acting no less arbitrarily. And for an administrative and adjudicatory body to act arbitrarily is, of course, contrary to law.

C. Regardless of the Standard Against Which the Company's Conduct is to be Judged, the Public Staff has not Shown that the Company Engaged in "Mismanagement," Nor Has It Quantified the Impact of Such Alleged "Mismanagement" – And the Commission Heard and Rejected the Public Staff's Identical Arguments in the Company's Prior Rate Case

In PS LFE No. 1 the Public Staff asserts that the Company had "***some*** degree of responsibility or fault" for past environmental practices. (Id. at 1 (emphasis supplied).) It mentions specifically surface water discharge issues (seeps) as well as North Carolina's groundwater classification rules and standards, known as the 2L

[14] In *State ex rel. Utils. Comm'n v. Thornburg*, 314 N.C. 509, 516 (1985), the Supreme Court specifically warned that under Section 62-133(d) the Commission did not in fact have "unbridled discretion in exercising its judgment."

rules. Both subjects were addressed in detail in the Company's prior case, with the Public Staff's position being soundly rejected, yet both are revived again in this case. Both challenges ring exceedingly hollow.

The Public Staff insists that "unauthorized seeps that DEP has admitted to environmental regulators" violate the terms of the Company's NPDES permits. (Tr. vol. 15, 1442.) To put it in tort-like terms, the Public Staff claims "unauthorized seeps" are evidence of the Company's "culpability" for environmental violations – the Company is at "fault" for those violations. Setting aside the fact that the Public Staff assigns no actual dollar impact to customers of these "violations," to equate seeps with management imprudence is to be willfully blind and deaf to the actual story of the seeps.

That story was presented in detail by Company witness James Wells, and not contradicted by anyone. It covers multiple pages of his pre-filed testimony (see Tr. vol. 19, 186-90), and additional multiple pages of his stipulated and hearing testimony. (Id. at 453-61, 691-93.) The short version is as follows. All earthen dams seep; indeed, seepage is necessary to maintain the stability of the dam. Engineered seeps are designed to collect seepage within the dam structures. In 2010, EPA instructed the States with delegated authority under the Clean Water Act, which would include North Carolina, to evaluate seeps within the permitting process. DEQ decided it had other more pressing priorities, particularly since the effluent composition of the seep water was similar to effluent from the ponds themselves, but in substantially lower concentrations, and also as no other State was following through with EPA's request. In 2014, four years after EPA tried to induce the States to address seeps but with no action on that subject taken by DEQ, and in an effort to seek regulatory certainty as to seeps, DEP and DEC[15] sought to include all "areas of wetness" at their coal ash basins in their NPDES permits – and DEQ sat on the application for years. Eventually, in 2018 – *four years after DEP applied for the permits, and eight years after EPA's instruction to the States regarding evaluation of seeps* – DEP and DEQ agreed on a regulatory approach as to seeps, which has now been implemented.

Apart from the story's ending – which had not yet happened at the time – witness Wells gave essentially the same testimony in the Company's last case (see 2018 Order, at 177) and in DEC's last case. The Commission summarized this testimony in the prior DEC case:

> Company witness Wells testified on rebuttal … [in response to Public Staff witness Junis who] suggested that the existence of seepage at the Company's CCR impoundments is evidence of the Company's "culpability." Witness Wells explained that the Public Staff's position ignores (1) the fact that the EPA first directed permitting authorities to address seeps in 2010, (2) the Company's attempts to obtain regulatory certainty as to seeps, and (3) DEQ's challenges in implementing EPA's direction. Tr. Vol. 24, p. 226.

(2018 DEC Rate Order, at 250.) In both cases the Commission declined Intervenors' invitation to view seeps as evidence of mismanagement justifying cost disallowance. As it indicated in the Company's prior case, even the Joint Factual Statement underpinning the Company's guilty plea noted that "DEQ and DEP have been in long-standing negotiations as to whether seeps are a violation of law and since 2014 whether seeps should be covered by the NPDES permit … [and that according] to

[15] The merger of Duke Energy Corporation and Progress Energy, Inc. had by then occurred. The merger became effective in July 2012.

statements made in the criminal case, DEQ has currently not made a determination on this issue." (2018 Order, at 184 (record citations omitted).)

The Commission in the Company's prior case declined to view the seeps as evidence of mismanagement – because they are *not* evidence of mismanagement. Yet the Public Staff, like a broken record, wants in this case to re-litigate the exact same issue, on the exact same theory, with the exact same evidence – and expects a different result. The Commission should not countenance such conduct. Whether the existence of seeps – known by and disclosed to the environmental regulator, and the subject of long-standing negotiations between the Company and its environmental regulator regarding the best and most effective way of dealing with resulting environmental impacts (if any) – is in violation of the Clean Water Act is not an issue for the Commission. It is an issue for the environmental regulator and was resolved by the environmental regulator. The questions for the Commission are (1) whether the existence of seeps constitutes mismanagement, and, if so, (2) what economic consequences of that mismanagement are to be visited upon the Company. The answers are (1) No, and (2) Not Applicable – and even if (2) were applicable, no one, and certainly not the Public Staff, has calculated any economic consequence *to* be visited upon the Company.[16]

The groundwater story is much the same as the seeps/surface water story – the Commission dealt with this at length in its 2018 Order, and the Public Staff is once again engaged in being willfully blind and deaf. First, the Public Staff's assertion

[16] Sierra Club appears to suggest that the economic consequence for the existence of seeps is the cost of basin closure – hundreds of millions of dollars, so far. This is nonsense. The Company could have – and did, during the limbo period in which DEQ was either unwilling or unable to act on seeps – simply pump water seeping out of the basins back into the basins. (Tr. vol. 19, 460.) It was not required to close the basins on account of the seeps.

of “culpability” or “fault” is based wholly on what it alleges are the large number of “violations” of the 2L rules. As witness Lucas put it, there are “7,411 groundwater exceedances confirmed by DEP’s own groundwater monitoring data, in violation of the state’s 2L rules.” (Tr. vol. 15, 1442.) But relying upon a simple count of exceedances does not equate to mismanagement; rather, it constitutes “a very serious flaw in … [the] analysis [which is] misleading.” (Tr. vol. 19, 432.)

Characterizing this testimony as misleading is well merited in this case, because the testimony is based upon a complete misapprehension of the facts. The Public Staff’s position[17] is that the number of violations is a factor of sampling “new contaminants” because of movement of the contaminant plume. (Tr. vol. 15, 1665.) Witness Williams, who is an actual expert on groundwater, indicates otherwise. She testified that the Public Staff “tried to explain that … [its methodology] wasn’t flaw[ed] because groundwater is constantly moving, and therefore … every exceedance is a new example of where the groundwater has moved and contaminated … additional clean groundwater.” (Tr. vol. 19, 432.) But, she added “that actually isn’t how groundwater behaves.” (Id.) Rather, if the plume is stable, then these are not “new exceedances” (id.) – and the plumes at the DEP basins are, indeed, stable. As witness Wells stated, “[I]t’s sitting, and it's stable, and our multiple models say it will continue to do so for hundreds of years, as we see it, if we take no further action.” (Id. at 388-89; see also Tr. vol. 20, 26 (Company’s stable plume does not present health risk).)

[17] The position was articulated by Public Staff witness Junis in the DEC-specific hearings, but his articulation of that position is made part of the DEP Record through the Amended Stipulation. (See fn. 13, above.)

Simply counting exceedances is also "not a meaningful thing to do" (Tr. vol. 19, 432-33) because in the assessment phase of a groundwater investigation the number of "exceedances" will depend on the number of wells and the number of sampling events per well, which would be expected to increase as DEP and DEQ engage in the iterative process of delineating the plume. (Tr. vol. 17, 133).[18] As witness Wells indicates, as part of that process new wells have been installed, and the location of the compliance boundary has changed, such that some wells were reclassified as being located at or beyond a compliance boundary. (Tr. vol. 19, 191-92.) The number of exceedances today, given the extensive groundwater monitoring required in order to comply with CAMA and the CCR Rule, says nothing about any alleged mismanagement in the past. (Id. at 192.) To the contrary, DEP's "comprehensive assessment demonstrates responsible actions that enable the Company and its regulators to better understand the impacted areas and drive appropriate corrective action." (Id.)

Second, the Public Staff completely ignores the fact that the 2L corrective action rules are "remedial"-oriented as opposed to "compliance"-oriented. (Id. at 328-29.) The distinction is crucial to an understanding of why a 2L exceedance or "violation" is not necessarily an indication of mismanagement. But this is a distinction apparently completely lost on the Public Staff. It was explained in detail by witness Williams:

> [The distinction] is important because the class of remedial requirements, including North Carolina's 2L requirements, recognize

[18] As the Commission noted in the Company's prior case, witness Wells observed that "Any newly measured exceedances do not require a further site assessment and do not result in additional or escalating penalties, ***but are actually expected as additional assessment prior to a requirement to take corrective action***." (2018 Order, at 182 (emphasis supplied).) Yet another "*déjà vu* all over again" moment.

> that environmental contamination, including contamination that constitutes environmental harm, can result when an entity is in full compliance with all operational performance requirements. That is, a company may operate a facility in compliance with all waste and chemical management design and operating laws and regulations and still have releases to the environment that require either investigation or remediation under remedial laws.
>
> The practical reasons for this distinction are obvious. Operational performance requirements including specific permit conditions, while designed and intended to prevent environmental harm, are not fail-proof. These requirements may not adequately address all activities, all site-specific locations, all waste streams, or all chemicals with the potential to result in environmental harm. Our understanding and knowledge regarding how to achieve prospective protection is constantly evolving.

(Id. at 330.)[19]

Third, just as with seeps, the Public Staff completely ignores the actual history of the 2L corrective action rules and their relationship to permitted facilities, like DEP's ash ponds, that predated the promulgation of those rules in 1984.[20] Pre-existing facilities were expressly addressed in connection with the establishment of corrective action requirements. (Tr. vol. 19, 159 (witness Wells testified that the report accompanying the promulgation of the corrective action rules noted that "it is

[19] Exactly the same distinction was referenced by the Commission in the 2018 DEC Rate Order:

> Witness Wells also disagreed with the Public Staff's suggestion that any exceedance or violation of water quality regulations, no matter how minor or how long ago, leads to the denial of cost recovery for any activity that acts to "cure" the impacts of the violation. In addition to reiterating that not all exceedances of the 2L standards amount to a violation that requires corrective action under the 2L rules, witness Wells stated that even when an exceedance requires corrective action, the groundwater rules do not treat the exceedance the same way as, for example, the Clean Water Act treats an exceedance of an NPDES permit limit. When the latter is violated, he explained, the permittee is immediately subject to [a notice of violation (NOV)] and penalty, and must ensure the next discharge complies with the permit limit or risks a new NOV and escalating penalty. Tr. Vol. 24, pp. 244-45.

(DEC Order, at 298.)

[20] While the 2L rules themselves first came into being in 1979, their corrective action requirements were introduced in 1984.

probable that some violations do exist where facility construction predated the groundwater standards [and that DEQ would address issues when] NPDES permits come up for renewal").) And, indeed, groundwater monitoring requirements at a number of the ponds were addressed in the NPDES permitting process. (Id. at 165-66.) Beginning in 2009, DEQ "began systematically adding groundwater requirements to NPDES permits as they were reissued or modified" (id. at 163), and then "[a]s additional data became available and both the Company's and DEQ's understanding of groundwater impacts matured, [DEQ] issued a policy memo, dated June 17, 2011, titled 'The Policy for Compliance Evaluation of Long-Term Permitted Facilities with No Prior Groundwater Monitoring Requirements.'" (Id. at 163-64; see also Hart Ex. 12 (2011 DEQ Policy, or, simply, Policy).)

The 2011 DEQ Policy was described in detail by witness Wells. (Tr. vol. 19, 163.) As he indicated, the Policy included a detailed flow chart dictating the steps to be taken by the Department and the permittee (i.e., the utility) upon the identification of a groundwater exceedance near a coal ash pond, including (1) verifying the accuracy and significance of the results of the groundwater testing; (2) determining whether and to what extent the identified substance could be naturally occurring; and (3) evaluating other possible sources of the identified substance. After these steps had been completed, and after DEQ and the affected utility had determined that the exceedance was from an ash pond, the Policy required the parties to work together to develop a corrective action plan. Notably, the Policy itself indicates that enforcement action by DEQ – the issuance of a Notice of Violation, along with fines and penalties for non-compliance – would ordinarily be unnecessary unless the permittee was uncooperative through the process described in the flowchart. This underscores the "remedial" orientation of the 2L rules.

In this case, witness Wells testified that

> Impacts to groundwater around ash basins are not the result of mismanagement. The existence of groundwater exceedances at or beyond the compliance boundaries at these sites is a function of where these sites are on the timeline of groundwater assessment and corrective action under modern laws that have changed the way that unlined basins are viewed. As these views have changed, the Company has taken every action required by … [its environmental regulators] to address groundwater impacts as they have been identified.

(Tr. vol. 19, 184.) He presented similar testimony in the Company's prior case. (2018 Order, at 174.)

Just like with seeps, the Commission heard all of this evidence in the Company's prior case. (Id. at 181-83.) The Commission indicated that witness Wells "concluded that compliance with this process is not mismanagement and should not be held against DEP with respect to cost recovery." (Id. at 182.) It credited his testimony and expressly found that there was "insufficient evidence that the Company would have had to have engaged in any groundwater extraction and treatment activities absent the obligations imposed upon it by CAMA and/or the CCR Rule." (Id. at 183.) Yet, here we are again, with yet another instance of "*déjà vu* all over again" – nothing has changed, no new evidence from the Public Staff has been submitted, yet, once again, the Public Staff expects a different result.

CCR Costs sought for recovery in this case were expended in order to comply with requirements of CAMA, including its 2016 amendment, and the CCR Rule. CAMA and the CCR Rule are very prescriptive, and require the Company to take specific steps spelled out in their text in order to be in compliance. Witness Lucas asserts that "ultimate closure of all coal ash basins" will correct "environmental violations" (Tr. vol. 15, 1443), but the only "violations" the Public Staff identifies are surface water discharge requirements (allegedly violated by seeps) and exceedances under the 2L rules. However, witness Lucas fails to show any causal connection between the surface water discharge requirements or the exceedances and basin closure, because there is no causal connection. As witness Wells testified, "Under the CCR Rule and CAMA, closure of all of the Company's ash basins had already been triggered before the 2017 Rate Case was filed and the triggering factor was not groundwater impacts." (Tr. vol. 19, 191.)

The trigger for basin closure came either from CAMA directly or as a result of the CCR Rule's location requirements. CAMA and the CCR Rule are, of course *new* regulation – they did not even exist, nor did their triggering requirements, prior to 2014-15. Witness Bednarcik discussed the CCR Rule's triggering location criteria extensively during her cross-examination by the AGO. (See, e.g., Tr. vol. 12, 297-98 (closure required if the basin did not meet even one of the criteria); Tr. vol. 13, 21-22 (purpose of the criteria was to evaluate whether closure was mandated); id. at 24 (DEP did not meet the location requirement, so closure triggered).)

Witness Bednarcik noted further that the Company's ash basins were all lawfully permitted when first developed, and had been subject to permit renewals since they were first developed. (Id. at 68-69.) But, with the passage of the CCR Rule and CAMA, the Company was required to – and did – shift its ash management practices to comply with the new laws: "New change, new rule, new regulations. We have to comply with the new rules and regulations, and that is what we are doing." (Id. at 69.) She indicated further that basin closure resulting from the new legal requirements does not mean that past practices were unreasonable or imprudent. (Id.)[21]

There is also no causal connection with respect to the groundwater treatment systems the Company has been required to install to meet the prescriptive requirements of CAMA/CCR Rule, pursuant to agreement with DEQ. Had the Company been able to proceed under the 2L rules alone, natural attenuation of the groundwater plume would have been an option (Tr. vol. 19, 585; see also Tr. vol. 20, 26), and a considerably less expensive one. Under CAMA/CCR Rule, as opposed to the 2L rules alone, basin closure is required – not because of any mismanagement, but because of the mandates written into CAMA and the CCR Rule by the General Assembly and EPA.

The dissent in the 2018 DEP Rate Order recognized the lack of any causal connection as well:

> Had the Company's management of coal combustion wastes resulted in no exceedances of the state's 2L groundwater standards, no violations of any NPDES permits, no criminal prosecutions, and no civil or administrative lawsuits, the record taken as a whole shows that the Company would eventually have been required to undertake many or even most of the ash disposal activities now required of it by the CCR Rule and CAMA.

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[21] Just two days ago, EPA published a final agency determination in connection with financial responsibility requirements under Section 108(b) of the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), 42 U.S.C. § 9608(b). In the course of confirming its determination not to impose financial responsibility requirements upon, *inter alia*, the electric power generation, transmission and distribution industry (of which DEP is of course a part), EPA noted that the CCR Rule "established a first-ever comprehensive set of minimum requirements for the management and disposal of coal ash in landfills and surface impoundments." 85 Fed. Reg. 77384, at 77392 (Dec. 2, 2020). Based upon its systematic evaluation of the CCR Rule and, in particular, the damage cases referenced and discussed in that Rule, EPA also found that "overwhelmingly, the industry was operating responsibly within the current modern regulatory framework." Id. at 77391. EPA's findings and final agency determination thus validate witness Bednarcik's observations that the CCR Rule's requirements were truly "new" and that the Company's pre-CCR Rule practices were reasonable and prudent.

(See 2018 DEP Rate Order, Commissioner Clodfelter concurring in part and dissenting in part, at 9.) The lack of a causal connection means that the Public Staff cannot show that any of the CCR Costs sought for recovery should be disallowed because of "environmental violations."

During her direct examination, Commissioner Clodfelter gave witness Bednarcik a homework assignment – to determine whether it was possible to break out the costs necessitated under CAMA and/or the CCR Rule for 2L rule exceedances beyond the compliance boundary. Witness Bednarcik did her homework and reported back when she was on the witness stand in the rebuttal phase of the hearings. The answer was that it was not possible – because what would have been required by DEQ in the absence of CAMA and the CCR Rule, and operating just under the 2L rules, is unknowable because DEQ has wide discretion, and the Company simply does not know what would have been required under 2L alone. (Tr. vol 18, 48-50.) She concluded "Where we sit today is we have to comply with CAMA and CCR" (id. at 50) – the prescriptive rules and regulations that now govern what the Company must do and when it must do it.

In DEP Late-Filed Exhibit No. 8, the Company reiterated that it is not possible to isolate outside-the-compliance-boundary costs. Noting the prescriptive nature of CAMA and the CCR Rule, and that the 2L rule provides DEQ with considerable discretion in connection with groundwater corrective action, the Company stated "[i]t is unknown if the Company would have had to install the same number of wells, would have had to conduct the same type of groundwater modeling, or would have had to perform the same type of corrective action within the same time frame under 2L only." (Id. at 3.) The Public Staff already knows this, and witness Lucas' own testimony reflects that it knows this. He states that 2L rule costs "***cannot be quantified without undue speculation***." (Tr. vol. 15, 1444 (emphasis supplied).)

The questions for the Commission regarding the 2L rules are identical to the questions regarding seeps: (1) was there mismanagement, and, if so, (2) what economic consequences of that mismanagement are to be visited upon the Company. The answers once again are (1) No, and (2) Not Applicable – and even if (2) were applicable, once again no one, and certainly not the Public Staff, has calculated any economic consequence *to* be visited upon the Company.

D. The Legal Framework for Cost Recovery – Prudence, Including Compliance with Industry Standards and Quantification

The legal framework regarding cost recovery is long-established, and was well articulated by the Commission in the prior DEP and DEC cases. First, the operating principle underlying rate regulation generally is that the utility's reasonable and prudently incurred costs are recoverable in rates. (2018 Order, at 196; DEC Order, at 257-58, 265-66.) Second, under the evidentiary presumptions governing cost recovery, the entirety of the utility's costs is deemed to be reasonable and prudent unless challenged by an intervenor. (2018 Order, at 196; DEC Order, at 259-62.) Third, if costs are challenged, the Commission must assess their prudence. (DEC Order, at 258-59, 265-66.)

Assessing prudence requires the Commission to apply a set of rules and guidelines that have been developed over the past 100 years. As Company witness Steven Fetter testified, "the concept of prudence began in 1923 in a dissent from

Justice Brandeis of the US Supreme Court …." (DEC Tr. vol. 26, 93;[22] see *Missouri ex rel. Sw. Bell Tel. Co. v. Pub. Serv. Comm'n,* 262 U.S. 276, 306-07 (1923) (Brandeis, J, concurring and dissenting).) Those rules and standards do not include "culpability." In his testimony, witness Fetter held up as a visual aid one volume of a two-volume reference work ("The Process of Ratemaking"; see DEC Tr. vol. 26, 93; https://www.youtube.com/watch?v=PESiQ189BSc at approx. the 5:33 mark) and indicated that the index of the two volumes had "35 subcategories discussing various means of assessing prudence and what it means …[but that he] found nowhere in the two-volume text any mention of culpable or culpability." (DEC Tr. vol. 26, 93.)

In North Carolina, for at least the last 30+ years, the prudence framework has been applied as articulated by this Commission in its Order entered in Docket No. E-2, Sub 537 (the 1988 DEP Rate Case), in which the Commission approved, with some exceptions, costs DEP incurred in connection with the construction of Unit 1 of the Shearon Harris nuclear plant. (See Order Granting Partial Increase in Rates and Charges, Docket No. E-2, Sub 537 (Aug. 5, 1988) (1988 DEP Rate Order).) There, the Commission set out the following principles governing the question of prudence:

First, the standard for judging prudence is "whether management decisions were made in a reasonable manner and at an appropriate time on the basis of what was reasonably known or reasonably should have been known at that time. … [T]his standard … must be based on a contemporaneous view of the action or decision

[22] Pursuant to its Order Allowing Duke Energy Progress, LLC's Motion Requesting that the Commission Take Judicial Notice of Certain Evidence Introduced in the Duke Energy Carolinas, LLC Specific Hearing, entered in this Docket on December 1, 2020, the Commission has taken judicial notice of all references in this Brief to the transcript from the DEC-specific hearings.

under question. Perfection is not required. Hindsight analysis – the judging of events based on subsequent developments — is not permitted." (Id. at 14.)

Second, challenging prudence requires a detailed and fact intensive analysis, and the challenger is required to (1) identify specific and discrete instances of imprudence; (2) demonstrate the existence of prudent alternatives – but a decision cannot be imprudent if it represents the only feasible way of accomplishing a goal; and (3) quantify the effects by calculating imprudently incurred costs. (Id. at 15.) As to quantification,

- The Commission can only disallow imprudent *expenditures* – that is, actions (even if imprudent) with no economic impact upon customers are of no consequence. As the Commission put it, "There can be imprudent actions without any economic impact. An imprudent decision or action can actually benefit the ratepayer economically. Thus, the identification of imprudence is not in itself sufficient." Id. The Commission rejected the importation of tort or "culpability" concepts into the prudence framework, and kept its focus where it statutorily belongs – upon rate regulation.

- The proper amount chargeable to customers is what the expenditure would have been absent the imprudent acts or decisions of management – in other words, the disallowance must be calculated as the difference between the (presumably) higher cost imprudent action and the (presumably) lower cost prudent action.

The North Carolina Supreme Court found "no error" in the Commission's articulation of the prudence framework in *State ex rel. Utils. Comm'n v. Thornburg*, 325 N.C. 484, 489 (1989), and the framework was most recently followed in the Commission's February 24, 2020 Order in Docket No. E-22, Sub 562 (2020 Dominion Rate Order, or, simply, Dominion Order), at 116.

A key factor in the prudence framework requires a challenger to identify "specific and discrete instances of imprudence." Necessarily embedded in this factor is an evaluation of the degree to which the utility has or has not acted consistently with industry standards. As two of the leading modern commentators on utility regulation put it in their treatise on utility regulation:

> Electric and natural gas utilities are required to follow a set of basic standards and practices, which together constitute *Good Utility Practice*. FERC defines *Good Utility Practice* for regulated electric utilities as follows:
>
> > Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of *reasonable* judgment in light of the facts known *at the time the decision was made*, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

Jonathan A. Lesser & Leonardo R. Giacchino (Lesser & Giacchino), *Fundamentals of Energy Regulation* 40 (Pub. Utils. Reports, Inc., 1st. ed., 2007) (citation omitted) (emphasis in original). Prudence is an attribute of "Good Utility Practice," and "Good Utility Practice" includes "the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period." (Id. at 40-41.) That is, Good Utility Practice – prudence – is judged in relation to the utility's conformance with industry standards.

Even a dissenting commissioner in DEC's last rate case made the point that industry standards are the touchstone for prudence. (See 2018 DEC Rate Order, Commissioner Clodfelter concurring in part and dissenting in part, at 5-6 fn. 12.) There, the dissent cites to Hempling, *Regulating Public Utility Performance* (ABA, 2013) for the proposition that "the standards for imprudence and negligence are essentially alike." While it appears that the dissent is using the citation to imbue prudence with some tort-like "negligence" concept, Hempling's actual meaning is evident from the full quotation, which the dissent leaves out: "The prudence standard, in short, is 'akin to the common-law standard for negligence: ***Did the utility act in a manner consistent with the performance of other similarly-situated contemporary utilities? If it did, its action cannot fairly be deemed the result of imprudent management.***'" (Id. at 237 (emphasis supplied; citations omitted).) Context is everything, whether one is reading a historical study submitted in this case as a Joint Exhibit, or a treatise, or a law review article, or a reported case opinion. The full context of the cited quotation makes the point that industry standards supply the rule of conduct for prudence, and only in that sense is prudence "akin" to negligence. And the evidence shows that in every instance of relevance to CCR Cost recovery, DEP met or exceeded applicable industry standards.

In his examination of the Junis/Maness panel while attempting (in vain, see pp. 15-17, above) to get the Public Staff to articulate "a standard [of culpability] that applies not simply to the facts of this case, but to other cases that the Commission might consider if they're going down the path of equitable sharing," Commissioner McKissick noted that the Commission "know[s] what the standards are for imprudence" and that the Commission "understand[s] why in this case there would not be grounds for finding imprudence." (Tr. vol. 15, 1807.) Commissioner McKissick's observation that proper application of the prudence framework means that Intervenors lose is entirely correct, as shown by DEP in the next section of this Brief.

E. Properly Viewed Through the Lens of the Prudence Framework, Including Industry Standards and Quantification, No Disallowance of CCR Costs is Permissible

The Public Staff resorts to "equitable sharing" because it concedes that it is impossible (or, at least "nearly impossible") to determine feasible alternatives to the actions taken by the Company in the past. (Tr. vol. 15, 1749-50.) It concedes also that tracing specific cost impacts to specific acts or omissions of the Company in the past is impossible. (Id. at 1770.) Assessing alternatives and quantifying costs are hallmarks of the prudence framework. The Public Staff concedes, therefore, that disallowance of CCR Costs under the prudence framework would be impermissible, except of course, through a Garrett & Moore-type prudence analysis. But the Garrett & Moore-type analysis consists of those witnesses' review and critique of the Company's activities undertaken during a time period contemporaneous with when the costs were incurred – from September 1, 2017 through February 29, 2020 in this case. By contrast, the "fault"-based attacks on the Company's conduct seek to disallow contemporaneously incurred costs by having the Commission review alleged actions or omissions of the Company that occurred long before – in some cases decades before – the costs were incurred. This is improper under the prudence framework, as it involves mere "guesswork" and speculation (2018 DEC Rate Order, at 263), not the rigorous and detailed factual inquiry the prudence framework requires. As the Commission found in the prior DEC case, even if past conduct could be characterized as imprudent, "the question of responding to new regulations and new standards … is a totally separate question." (Id. at 274.)

Viewing the evidentiary record through the lens of the prudence framework, including industry standards – as the Commission must do, as there is no other lens through which to view it – answers the cost recovery issues presented in this case just like it answered them in the Company's prior rate case. This goes well beyond Intervenors' failure to quantify impacts, although that failure alone would justify rejection of their disallowance claims. (See pp. 36-40, below.) In addition to Intervenors' failure to quantify, DEP is entitled to recover CCR Costs in this case because it has proven that it acted reasonably and prudently throughout the pre-CAMA/CCR Rule period upon which Intervenors center their "fault"-based attack on the Company's conduct.

In addition, the Commission cannot lose sight of the fact that it has heard all of this before and already decided these issues. In the Company's prior case the Commission noted the limitations inherent in the Public Staff's approach were:

> [D]emonstrated by [witness Lucas'] inability to answer with any specificity on cross-examination: 'From 1920 until 2014, with respect to ... [the] Company's ash basins in this state, what should we have done differently and when should ... [it] have done it?" (Tr. Vol. 19, p. 35.) His response essentially was that "Somewhere along the line the Company should have taken some kind of action to not contaminate groundwater." (Id. at 36.) But the kinds of actions he appears to have favored – such as lining ash ponds when this was contrary to standard practice, or creating dry coal ash basins when for the most part the Company's industry peers were sluicing coal ash into wet basin impoundments, would (a) have cost money which would have been charged to customers, or (b) would have left the Company open to credible claims of "gold-plating," and therefore cost disallowance, which would have prevented the Company from moving forward with these suggested improvements in the first place. Witness Lucas and the Public Staff fault the Company for not taking steps that were not in accord with steps most of the industry was following, but at the same time disregarding responsibility of paying for that which they – in 20/20 hindsight – wish the Company had done.

(2018 Order, at 183.) The Commission also noted these same limitations in the prior DEC case (see 2018 DEC Rate Order, at 301), and held that it was therefore "not persuaded … that any past violations by DEC, or many of its past coal ash management practices, support the discrete amounts of cost disallowances advocated by the Intervenors and the Public Staff in this case." (Id. at 302.)

This is, once more, "*déjà vu* all over again," and nothing Intervenors have submitted in this case moves the needle from the manner in which these same issues were decided in the last case.

1. Intervenors' Inability to Quantify the Impacts of Their Attack on the Company's Historical Coal Ash Management Practices Doom Their Disallowance Recommendations

In their pre-filed direct testimony in the currently pending DEC case (E-7, Sub 1214) neither Sierra Club nor the AGO submitted "quantification" evidence with respect to the Company's historical coal ash management practices.[23] That testimony was filed on February 18, 2020. On February 24, 2020, the Commission published the 2020 Dominion Rate Order, which re-affirmed that quantification of impact was a requirement for cost disallowance. (See Dominion Order, at 129.) In this case, both Sierra Club and the AGO[24] have made attempts to meet the quantification requirement, but their attempts are wholly inadequate and fail.

Sierra Club's wholly inadequate quantification evidence was submitted by witness Mark Quarles. He testified that current costs would be smaller had the Company instituted dry ash handling sooner. (Tr. vol. 14, 613-14.) He indicated that the Commission need only "pick … [the] point in time" in the past when that conversion should have occurred (id. at 748), and then calculate the savings based upon a per ton cost for closing the Company's basins. But, he conceded, the per ton

[23] Neither, of course, did the Public Staff – rather, it conceded that quantification was inherently speculative and impossible, and, therefore, in both the DEC case and in this case (and in the prior DEC and DEP cases) the Public Staff instead espoused "equitable sharing."

[24] Post-Dominion Order, with the permission of the Commission and over the objection of DEC, the AGO did file Supplemental Testimony of witness Hart espousing his "time value of money" theory.

handling cost he used in his calculation is at *today's* cost (id.), and he had "no idea" what the costs would have been at his "pick a date" point in the past (id. at 750).

Moreover, the Commission dealt with this precise issue in the Dominion Order. Noting that no party in that case presented evidence as to what CCR costs, if any, "might have been avoided if [Dominion] had used a different approach to managing its CCRs at some point during the last several decades," the Commission observed:

> For example, one could argue that [Dominion] should have converted all of its coal-fired plants to dry ash handling at least at some time during the 1990s. However, to quantify the costs and benefits of this strategy would require establishing, with some level of certainty, the costs that [Dominion] would have incurred for such conversions, and the savings in present CCR remediation costs that would have resulted from such conversions. In addition, [Dominion] could have been entitled to recover those conversion costs, plus a return on its increased rate base, from its ratepayers over the past several decades.

(2020 Dominion Rate Order, at 129.) Witness Quarles did not establish with *any* "level of certainty" what the past costs would have been; he simply had "no idea" of their magnitude. He also did not factor in the capital costs, and the Company's earnings thereon, in connection with the dry ash conversion which he states should have occurred at his "pick a date" point in the past. (Tr. vol. 14, 747-48.) The Commission has already rejected his approach, and there is no reason to resurrect it now, nor did he supply any evidentiary basis to support it.

The AGO's quantification attempt, through witness Hart, fares no better. First, witness Hart reprised his DEC-Supplemental Testimony "time value of money" quantification method. His methodology, which enjoys no support whatsoever from any peer reviewed authority (see Hart DEP Cross Examination Ex. No. 10, at 76, 88), fails to quantify any impact of supposed imprudence upon customers, because it merely shows at various earlier points in time costs equivalent to current CCR Costs, meaning that the "difference" in cost under his methodology is actually zero. (Tr. vol. 11, 163.)

Witness Hart also advocated cost disallowance for what he called "old" basins, which he characterized as having been taken out of service many years ago but not closed; he called this disallowance "Step B." (Tr. vol. 13, 546-47.) Step B applies to inactive basins at the Company's Asheville, Cape Fear, H.F. Lee, Roxboro, and Sutton facilities. (Id.) There are multiple issues with witness Hart's Step B. First, he assumes that the inactive basins were not in use – but, to the contrary, they were (and, if still unexcavated, are) in use, if for no other reason than to store coal ash, a byproduct of the generation of electricity.[25]

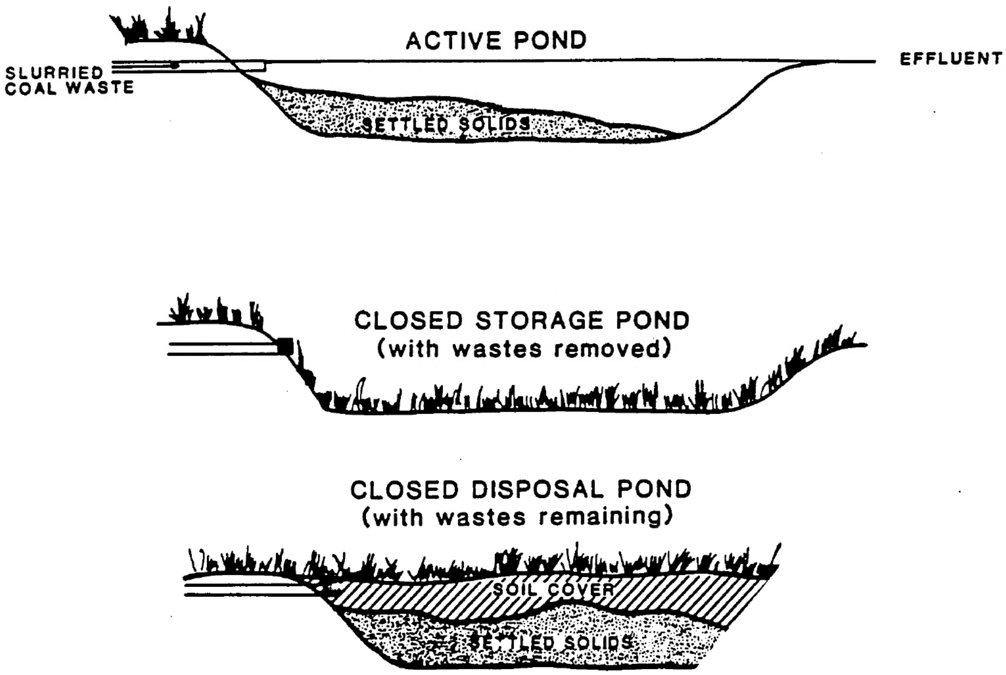
Witness Hart assumes further that the inactive basins should have been "closed" (id. at 895-96) at some (undefined) point in time in the past (Tr. vol. 14, 24), although he cannot say what exactly should have been done to "close" them. He therefore utterly fails to take into account the fact that DEP's practices with respect to the inactive basins conformed to industry standards. (Tr. vol. 19, 323-24.) Witness Williams testified that the 1988 EPA Report to Congress, which her office prepared, described the life cycle of an ash basin, and even depicted it as shown below. (See Joint Ex. 13, at 4-11 – 4-12.)

[25] Witness Hart opined that visiting costs today for closure of the inactive ponds was unfair to today's ratepayers, although he conceded that he is no expert in ratemaking. (Id. at 896.) That is undoubtedly true, and, as shown below (see pp. 99-100), there is no unfairness whatsoever in that the costs are being incurred today, and there is no evidence whatsoever that they should have been incurred at some point in the past.

4-12

EXHIBIT 4-2

TYPICAL SURFACE IMPOUNDMENT (POND) STAGES



Witness Williams noted that the final picture was of a "closed disposal pond with waste remaining in it … end[ing] up with soil over the filled solids and then some type of vegetation that ends up growing." (Tr. vol. 19, 710.) She characterized this closure method as "pretty much the standard approach at the time" (id.),[26] and witness Wells noted that with regard to "closure and treatment of those ponds over time," DEP

[26] See also Joint Ex. 8 – a 1982 publication by the Electric Power Research Institute (EPRI), so, according to Intervenors, representative of "industry" knowledge and practice (see Tr. vol. 14, 600-01 (witness Quarles); Tr. vol. 15, 1476-79 (witness Lucas)). The EPRI report states: "The most common closure practices employed for retired utility waste disposal sites are (1) covering with soil followed by revegetation; (2) pond draining and backfilling with soil; and (3) pond abandonment." (Joint Ex. 8, at 8-1.)

adhered to industry standards throughout the timeframe in which it operated coal ash basins. (Id.)

Moreover, witness Hart failed to consider any costs associated with earlier closure of the inactive basins, at whatever undefined time in the past he posits they should have been closed. Just as earlier conversion to dry ash handling would have required the Company to incur costs that it would have recovered, and upon which it would have earned a return, so too any closure involving (for example) an engineered cap (see Tr. vol. 14, 25) would have involved costs upon which the Company would have earned a return. Witness Hart also did not consider the impact of having to re-do any earlier closure. (See pp. 61-62, below.) There is simply no evidence that any earlier closure would have obviated the need for the Company to incur the costs that it is currently incurring in order to comply with the new legal requirements of CAMA or the CCR Rule.

Intervenors' failure to quantify costs and failure to account for the Company's incurrence of other costs (and earnings thereon) means that even were the Company's past actions to be deemed imprudent, no disallowance would be appropriate.[27] But, in fact, the Company's past practices were not imprudent. Therefore, on the merits, no disallowance is warranted.

[27] In the prior DEC case, the Commission discussed at length the Intervenors' often contradictory recommendations regarding what DEC should have done differently in the past. (2018 DEC Rate Order, at 316-18.) It stated that, as a result, "insurmountable obstacles exist[ed] to quantify the alleged offsets that are a fundamental element to Intervenors' disallowance theory." (Id. at 318.) Noting further that the Public Staff, "the agency required by statute to audit rate requests and recommend adjustments," candidly admitted that it was unwilling to speculate about what should have occurred in the past, and what that would have cost, and concluded "[w]ithout any evidence sponsored by any witness quantifying what DEC should have spent in the past, the Commission has no basis for disallowing 2015-2017 DEC remediation costs in support of a theory that DEC should have done more prior to 2015." (Id.) Precisely the same observations may be made concerning the 2017-2020 costs the Company has expended and seeks recovery of in this case.

2. Industry Standards – Unlined Ash Ponds

Industry standards are the touchstone for prudence. As we have seen, the relevant question is, "***Did the utility act in a manner consistent with the performance of other similarly-situated contemporary utilities? If it did, its action cannot fairly be deemed the result of imprudent management.***" (See p. 33, above.)

DEP's continued operation of unlined basins until the change in law wrought by CAMA and the CCR Rule was compliant with industry standards. The Company proved this through the testimony of witness Williams, among others:

> [I]n evaluating whether a company operated reasonably it is certainly appropriate to compare that company to others in the same or similar industries. … EPA's 1988 CCR Report to Congress found that of the 483 CCR surface impoundments in the United States less than 10% (45) were found to be lined and of the 195 surface impoundments in the Southeastern United States (EPA's Region 4), less than 2% (3) were found to be lined.

(Tr. vol. 19, 282; see also p. 4, above.) Witness Williams' observation is further buttressed by the testimony of Rudolph Bonaparte, who demonstrated that the Company, consistent with its peer utilities in the Southeast, managed coal ash in unlined surface impoundments throughout the pre-CAMA/CCR Rule period. Witness Bonaparte's investigation was presented through a report (Geosyntech Report, Bonaparte Ex. 2) which found that over 90% of the CCR impoundments "were either directly reported or interpreted to be unlined" and that most of them were reported as being active in the timeframe of the investigation (2009-11). (Id. at 9.) The Company last constructed a basin in 1985, and of the eighty-two basins reported to be pre-1985 construction, only three had liners. One of those three required a liner due to site specific conditions (located in karst terrain) (Tr. vol. 17, 139), and another of those three is the Company's Sutton ash pond constructed in 1984, which is dealt with in detail below (see pp. 43-44) also reflected site-specific issues. Thus, approaching 100% of the pre-1985 basins in North Carolina, South Carolina, Georgia and Virginia that did not have site-specific issues were unlined. No Intervenor can say with a straight face that the Company deviated from the practices of the industry as a whole. Indeed, the AGO's coal ash witness in the last round of cases "testified that the majority of utilities continued to use unlined wet ash impoundments even after this timeframe, because '[t]he law allowed them to do it, and the law continued to allow them to do it.'" (2018 DEC Rate Order, at 267.) Witness Quarles in the Company's previous case testified to the same effect. (DEC Quarles Cross Examination Ex. 1, at 199 (utilities continued to use ash ponds because it was "convenient and there [was] no regulatory standard" prohibiting the practice).)[28]

EPA promulgated the CCR Rule in 2015, and that Rule (along with CAMA) dictated closure of the Company's unlined basins. EPA issued its proposed rule in 2010. The proposed rule contained three regulatory options – regulation under Resource Conservation and Recovery Act (RCRA), Subtitle C, which contains the EPA's hazardous waste rules and would have required liners; regulation under RCRA Subtitle D, the solid waste rules, which would have allowed existing ponds to operate "as is" for five years (i.e., without liners); and under an approach called "D Prime" which would have allowed unlined basins to continue to operate for the remainder of their useful lives. (Tr. vol. 20, 14.) Reviewing these options, witness

[28] This exhibit contains testimony from the prior DEP rate case. The Commission has taken judicial notice of coal ash-related testimony and exhibits from that case, and the exhibit was in any event introduced into the Record in this case by way of the Amended Stipulation. (See Tr. vol. 14, 710.)

Williams – with "an almost 50-year career centered on environmental protection and regulation, spanning government service with the United States Environmental Protection Agency (EPA, or the Agency) (over 17 years), a senior management position in the waste management industry (approximately 3 years), and consulting work (almost 30 years) in which … [she has] been a consultant to both private industry and government agencies on a wide range of environmental matters" (Tr. vol. 19, 205) – testified "So even as late as 2010, when EPA was putting out its proposed rule on this, it had not yet determined that it was necessary across the board to close unlined ponds prior to the end of their useful life …." (Tr. vol. 20, 14-15.)

Witness Williams indicated that liners in connection with the construction of ash ponds was a "site specific issue" until the CCR Rule was finalized. (Id. at 15.) The liner installed in 1984 at DEP's Sutton Plant demonstrates this – and demonstrates also that DEP was responsive to potential environmental impacts of its operations, even when those operations were ultimately shown *not* to be the cause of a perceived environmental issue.

The Sutton clay liner saga is the subject of extensive testimony from witness Wells, both pre-filed (Tr. vol. 19, 152-58) and live (id. at 718-20). In summary, the issue at Sutton related to high chloride (i.e., salt) concentrations discovered in production wells operated by a neighboring manufacturing facility, Hercofina. When investigated by DEQ in 1978, the high chloride concentrations were viewed as being associated with the Sutton cooling pond, not the ash pond (Old Basin), a view that ultimately proved to be correct. (See Hart Ex. 24B at PDF p. 105; Tr. vol. 19, 153, 719-20.) At the time, the intake for the cooling pond in the Cape Fear River was in a location with a large tidal influence, which brought saltwater into the cooling pond. (Tr., vol. 19, 719-20.) In the late 1980s the Company moved the cooling pond intake several miles upstream, and, with fresher water drawn into the cooling pond, the chloride issue dissipated. (Id. at 154, 720.)

Nevertheless, when DEP proposed the construction of a new ash pond at Sutton in the early 1980s, Hercofina again raised the issue of potential contamination from the ash pond. DEP had by then obtained regulatory approval for construction of an *unlined* basin, but, in conjunction with DEQ, it agreed to construct the new basin with a clay liner. (Id. at 153.)To further assuage Hercofina's concerns, DEP also agreed to establish existing groundwater quality prior to construction of the new basin, and groundwater wells were installed for this purpose in 1984. (Id. at 153-54.)

In sum, DEP implemented in 1984 a groundwater monitoring program at Sutton and installed in conjunction with DEQ a clay liner at the new Sutton ash basin to address an environmental issue that actually arose not from the plant's Old Basin but from its cooling pond. But it did so in recognition of a potential future risk from the new basin, in light of concerns expressed by its neighbor, Hercofina. (Id. at 720.) Importantly, however, DEQ did not require DEP to take any action regarding installation of a liner at either the Old Basin or any of its other existing basins (id. at 154) or at a new basin that DEP constructed at its Cape Fear plant in 1985 – a year after the new basin at Sutton was built. (Tr. vol. 18, 23; Tr. vol. 19, 156.) The Sutton clay liner saga illustrates that CCR and its management is a site-specific issue, that DEP was attuned to potential for environmental degradation, and that DEP with its environmental regulator, DEQ, responded appropriately to that potential.

When Intervenors fault DEP for continuing CCR management in unlined ponds and not switching to dry ash handling earlier, they must contend with DEP's conformance with industry standards in continuing to operate the ponds – and they do not. This is in addition, of course, to Intervenors' complete inability to quantify the effects. The fact that the 1984 ash basin at Sutton was constructed with a clay liner did not prevent that basin from being excavated in the aftermath of CAMA and the CCR Rule. (Tr. vol. 15, 1718-19.) Intervenors have not presented one iota of evidence suggesting that even if the Company's ash basins had been lined when constructed, or retrofit with liners after construction, the presence of liners would have made any difference to the basin closure activities – and their attendant cost – that the Company has had to undertake post-CAMA and the CCR Rule, in order to comply with the new legal requirements of CAMA and the CCR Rule.

3. Industry Standards – Groundwater Monitoring

Intervenors contend that the Company engaged too late in "comprehensive" (Lucas – Tr. vol. 15, 1480-81) or "proactive" (Hart – Tr. vol. 13, 541, 690-91) groundwater monitoring at its coal ash basins. They do not define these vague and nebulous terms. Once again, their claims run afoul of the fact that the Company met or exceeded all applicable industry standards.

Witness Williams unequivocally testified that DEP was well ahead of its industry peers in initiating and conducting groundwater monitoring at its coal ash ponds. She summarized the evidence supporting her observation during the DEC-specific hearings, noting that "[F]rom the '80s all the way through to the time frame when EPA was doing its proposed rule, you were seeing numbers like 33 -- 32 percent, 33 percent, 35 percent of these facilities had groundwater monitoring installed, and so I think it really is noteworthy that by the time you get to 2008, you know, when Duke had completed installing initial well systems at all of its facilities that hadn't already installed them due to a requirement in an NPDES permit, they installed it at the rest of the facilities by 2008." (Tr. vol. 19, 624-25.) In the DEP-specific hearings she added:

> So I would just say, if you want to compare both to what EPA knew and to what industry practices were, I'm not going to repeat all the statistics that I put on the record in the DEC case, but unlined ponds were the most prevalent and common type of pond that was in use throughout the 1980s, well into the 2000s at the time of the CCR final rule. ***And that DEP was ahead of the curve, in terms of industry standards, of starting its groundwater monitoring, before it was required, before the majority of the industry had it at all sites. And DEP did begin undertaking coordination with DEQ to react to the results of the groundwater monitoring. I think they were a leader in this particular situation.***

(Tr. vol. 19, 704-05 (emphasis supplied).)

No witness in this proceeding had the depth of knowledge and expertise on the subject of groundwater regulation possessed and displayed by witness Williams. She stated, regarding DEP's groundwater monitoring program, "I believe in light … of the fact that [DEP] had installed groundwater monitoring systems before many of the industry had done it at all their facilities and were then improving them and working with them, I believe they did what you would reasonably expect a prudent utility to do." (Id. at 654.) Intervenors are unable to refute this expert observation.

EPA never required groundwater monitoring at any coal ash pond until it included a monitoring requirement in the CCR Rule – in 2015. (Id. at 440.) By then, DEP was already monitoring groundwater at every single one of its ash basins, and had been doing so for years – in coordination with its environmental regulator, DEQ. Working with DEQ is of course the prudent course. As the Commission noted in the prior DEC case, "Determining the number and placement of monitoring wells, ***not an inexpensive endeavor***, is an inexact science." (2018 DEC Rate Order, at 264 (emphasis supplied) (citation omitted).) Not working with DEQ would have been imprudent – had the Company charged ahead and DEQ decided later that a different number of wells, or placement of them in different locations, would have been better, the Company would have incurred costs – potentially significant costs – and the Public Staff and other Intervenors would no doubt have objected to those costs being passed along to customers.

The picture Intervenors paint is of an environmental regulatory agency – DEQ – that was disengaged, and a regulated entity – DEP – that was passive. Neither part of the picture is true. The undisputed evidence indicates that Colleen Sullins, who began her career at the Division of Water Quality within DEQ in 1992 writing permits for large industrial users and ended up being the Director of the Division of Water Quality in 2007 before retiring in 2011, testified that "Coal ash has been an issue that I dealt with for most of my career at the Division of Water Quality." (DEC Hart Cross Examination Ex. 4, at 22.)[29] And the reason is obvious:

> [T]he power companies [meaning DEC and DEP], we were constantly in interaction with them because we were issuing permits for them to do a variety of different things.
>
> So you know, they were sort of always on the radar like a large, a large permitted entity would be and a complex permitted entity because it involved multiple divisions trying to figure out how to issue the various permits for which they had responsibility and deal with the various issues.

[29] The exhibit was introduced into the Record in this case by way of the Amended Stipulation. (See Tr. vol. 13, 889.)

(Id. at 30.) Every single one of DEP's coal ash basins was permitted by DEQ, and those permits constantly came up for renewal on a periodic cycle. To portray DEQ as disengaged is to twist the facts into an unrecognizable shape, far removed from reality.

The notion that DEP was a passive bystander waiting for DEQ to tell it what to do also twists the facts into something far removed from reality. As witness Wells notes,

> Throughout its history of CCR management, the Company has worked in lock-step with its regulators to site, construct, and operate ash basins in compliance with regulatory and industry standards. When deemed necessary to address environmental conditions at its sites, the Company coordinated with regulators to develop a remedial response, including further groundwater monitoring and assessment. [DEP] also participated in voluntary efforts to help the industry and its regulators better understand the potential impacts of ash basins on the environment. These actions are affirmative evidence of prudence.

(Tr. vol. 19, 135-36.) Witness Wells went on to recount (id. at 149-58) the extensive efforts the Company took at its Mayo, Roxboro, and Sutton plants in the 1970s and 1980s to evaluate potential groundwater impacts – the very issue Intervenors identify in their attacks upon the Company. (See Tr. vol. 13, 537 (Hart: utility industry, including DEP, knew of "potential" for groundwater contamination as early as the 1980s); Tr. vol. 14, 598-99 (Quarles); Tr. vol. 15, 1477-81 (Lucas).)

Groundwater investigation at Mayo occurred in 1978-79, in connection with the Company's analysis of environmental impacts of the plant, which was then under consideration but had not as yet been constructed. The investigation is described in a report authored in 1979 by Edwin O. Floyd, a licensed engineer specializing in groundwater hydrology and titled "Evaluation of the Potential For Contamination of the Ground-Water Aquifer By Leachate From the Coal-Ash Storage Pond at the

Mayo Electric Generating Plant Site" (Floyd Report).[30] (Bednarcik Rebuttal DEP Redirect Ex. No. 1.) The Floyd Report concluded, among other things, that the clay-rich soils at the Mayo plant site would preclude any significant adverse impact upon groundwater from the operation of Mayo's unlined ash basin:

> Soil conditions at the proposed ash pond site at the Mayo Electric Generating Plant are adequate to provide excellent protection to the ground-water aquifer both in preventing significant leakage from the pond and in reducing the concentrations of the heavy minerals by filtration before the leachate reaches the aquifer. …
>
> In consideration of the natural action of the soils on heavy minerals in the leachate, the dilution effects of mixing with the natural ground water, and the fact that there are no water supply sources or major water courses for miles downstream from the ash pond dam, ***it is difficult to imagine that any significant adverse impact on the ground water aquifer could be caused by ponding of the ash wastes at the proposed site***.

(Id. at 14-15 (emphasis supplied).)[31] In fact, even following years of groundwater monitoring, the same conclusion was reached in Mayo's September 2015 Comprehensive Site Assessment Report: "No imminent hazard to human health or the environment has been identified as a result of [contaminant] migration from the ash basin." (Tr. vol. 19, 150.)

[30] The Floyd Report was generated in connection with an Environmental Impact Statement required for the Mayo plant, and that process is described in detail below. (See pp. 66-70, below.)

[31] The Floyd Report's reference to the clay-rich Piedmont soils and their attenuative capacity is echoed by EPA's investigation of, among other sites, DEC's Allen Plant several years later. (See Joint Ex. 10.) The investigation was conducted through a contractor, Arthur D. Little, Inc., and the Allen Plant was selected for study inasmuch as EPA viewed it as representative of sites located in the Piedmont region (Tr. vol. 19, 161), which is where Mayo is located (id. at 152). The Arthur D. Little Report concluded that "Data from the study suggest that no major environmental effects have occurred at any of the six sites." (Joint Ex. 10, at iii.) As witness Williams notes, the Arthur D. Little report concluded that the Piedmont soils prevented arsenic from migrating and impacting groundwater. (Tr. vol. 19, 288.) And as witness Wells testified, the Arthur D. Little report, along with DEC's own internal investigations at Allen, concluded that the wet sluicing of coal ash to Piedmont region ponds did not have a significant impact to groundwater: "And the key conclusion, not just from Duke's internal voluntary work … [but also the] A. D. Little work, was the same. And that is the impacts were localized, they weren't seeing a risk, they weren't seeing a significant impact." (Id. at 391.)

The Floyd Report also recounts prior investigations at DEP's Roxboro plant and came to similar conclusions: the naturally occurring clay soils in the region "'can give essentially complete protection against the trace elements that occur in ash pond sludge.'" (Id. at 152, quoting Floyd Report, at 12-13.) And the groundwater monitoring program initiated in the 1980s at Sutton has been discussed already. (See pp. 43-44, above.) It, too, indicated no concerns with respect to contamination from the Sutton ash ponds. Indeed, in 1995 DEQ scaled back the monitoring frequency requirements at Sutton, at a time when the Company was under its NPDES permit required to sample for arsenic, chloride, iron, selenium, total dissolved solids, water level, and pH. (Tr. vol. 19, 154.)

It is against this backdrop that witness Lucas indicates that DEP should have installed a "sufficient" system of wells when exceedances began to be detected. (Tr. vol. 15, 1493.) He does not put a date to this opinion,[32] although his testimony indicates that at least by the early 1980s the Company should have known about the potential for groundwater contamination from its unlined basins. (Id. at 1477-81.) Further, he criticizes the Company for failing to "improve or modernize" its groundwater monitoring practices in light of the "state of knowledge" by that time, and states that the Company should have installed a "comprehensive" monitoring well network in the 1980s "to determine if the risk was materializing." (Id. at 1480-81.)

There are multiple responses to this criticism. First, the criticism appears to be leveled from the Public Staff's misconception that groundwater monitoring at each

[32] In his testimony in DEP's prior case, he indicated only that "Somewhere along the line the Company should have taken some kind of action to not contaminate groundwater." (2018 DEP Rate Order, at 183.)

of DEP's coal ash basins is the only way in which environmental impacts can be detected. This is simply untrue. Environmental impacts can also be detected through surface water monitoring, which was required by the plants' NPDES permits, and this was particularly prevalent in 1980s thinking. (Tr. vol. 19, 666-67.) Witness Wells indicated that at the Mayo plant, monitoring of Crutchfield Branch was written into the plant's original NPDES permit in 1982 in order to confirm that any groundwater impacts were not being realized in that surface water stream.[33] (Id. at 674-75.) Geological considerations also come into play, as witness Wells testified – with extensive studies of ash basins in the Piedmont region showing no significant impacts from the basins, the Company's Piedmont region plants that did not have early monitoring – Weatherspoon, Cape Fear, and H.F. Lee – were thought to be similarly situated, again particularly in the 1980s. (Id. at 667.)

Second, as witness Williams testified, it may be easy to look at a monitoring well network with 20/20 hindsight (although, of course, doing so would run afoul of the prudence framework, which forbids hindsight analysis (see pp. 30-31, above, and pp. 63-71, below) and say that a network constructed in the 1980s was not "comprehensive" enough by today's standards. (Tr. vol. 19, 716.) But it was not until "many decades later … that we underst[ood] that it takes a very large number of wells to truly understand the complexity of what's going on in the subsurface adequately." (Id.) Witness Lucas simply does not have the depth of knowledge and experience to make pronouncements about what should or should not have been done in the 1980s

[33] The lack of any exceedance of water quality standards in Crutchfield Branch (Tr. vol. 19, 675) is further confirmation of the Floyd Report's conclusion that the Mayo ash basin would not pose a significant threat to groundwater, despite the fact that the basin was unlined.

with respect to groundwater monitoring; witness Williams clearly does – and her pronouncement is diametrically at odds with his.

Third, there is no evidence that environmental conditions at any of DEP's ash basins required any monitoring in addition to the monitoring that DEP was already engaged in – to the contrary, the results of the 1980s studies did not indicate the need for additional monitoring, and the ultimate conclusion of EPA's 1988 Report to Congress was that there was no need to change then-current coal ash waste management practices, inasmuch as those practices "appear[ed] adequate for protecting human health and the environment." (Joint Ex. 13, at 7-11.) Witness Wells testified:

> Based on [DEP's] internal studies, the Arthur D Little, Inc.'s study, the 1988 EPA Report to Congress, and the 1991 EPRI Study, it was reasonable for the Company to conclude that continuing wet disposal of coal ash would have no significant impact on groundwater at [DEP] sites. Thus, while the Company may have been aware in the 1980s that unlined impoundments, in general, could potentially impact groundwater, there was no substantial evidence showing that there was significant impacts resulting from ***[DEP's] facilities***. Where potential offsite impacts were identified, such as at Sutton, the Company responded appropriately to address those concerns.

(Tr. vol. 19, 162.)

Spending money in the 1980s on a "sufficient" or "comprehensive" (whatever witness Lucas might mean by those terms) system of wells at DEP coal ash basins, in the face of the Company's own conclusion – concurred in by DEQ – that no significant impact from the basins existed, in the face of EPA/Arthur D. Little's identical conclusion, and in the face of EPA's conclusion that existing coal ash management techniques were adequate, would indeed have opened the Company to “credible claims of ‘gold-plating,’ and therefore cost disallowance” (2018 DEP Rate Order, at 183) – and the Public Staff and AGO would no doubt have led the charge.

The post-1980s picture gets no better for Intervenors, as their portrayal of the Company as passively waiting for DEQ to tell it what to do again is belied by the facts. As indicated above (see p. 50), at Sutton DEQ reduced its required level of groundwater monitoring frequency in 1995, and monitoring at Weatherspoon was allowed by DEQ to lapse in 2000.[34] (Tr. vol. 19, 154, 162.) And in the early 2000s, while EPA began to consider anew potential regulation of ash ponds, the agency indicated that it needed to gather significantly more information. At that time, guidance from EPA to industry on likely outcomes of any new regulation was minimal (id. at 248), and the direction EPA might take was unclear. (Id. at 178).

In an effort to fill the information gap the Utility Solid Waste Activities Group (USWAG), an industry trade group, worked with EPA to formulate a plan (USWAG Action Plan, see Hart Ex. 13) to implement a voluntary groundwater monitoring program to help federal and state regulators expand their knowledge of potential groundwater impacts from unlined ash basins. DEP participated voluntarily in the program and undertook groundwater monitoring at all of its facilities; it is this participation that prompted witness Williams to note the Company’s industry leadership in groundwater monitoring. (See pp. 45-46, above.)

[34] Sutton and Weatherspoon are the two DEP plants located in the Coastal Plain, as opposed to the Piedmont. (Tr. vol. 19, 162.) Their soil characteristics thus differed from the clay-rich Piedmont soils that were found in the Floyd Report and the Arthur D. Little Report (Joint Ex. 10) to provide attenuative capacity. Yet the years of monitoring at Sutton and Weatherspoon, as required by NPDES permits and under DEQ’s supervision, validated the notion that the Sutton and Weatherspoon basins posed no significant environmental threat. In addition, the clay liner at the 1984 Sutton pond was thought by DEQ to “likely attenuate, by ionic exchange and absorption/adsorption, the majority of contaminants.” (Hart Ex. 24B at PDF page 45.)

Far from passively awaiting direction from DEQ, the Company acted when data showed the need for further action. Sutton, again, illustrates this – and illustrates once again that the Company took action to address potential risk to human health even when the Sutton ash basins were ultimately shown *not* to be the cause of the perceived environmental issue. As witness Wells testified:

> In 2008, groundwater data at Sutton showed exceedances of boron at the compliance boundary. [DEP] alerted DEQ to this data and initiated an investigation to better understand the data. The subsequent investigation involved two phases: Phase I, involving temporary wells, was submitted to DEQ on February 11, 2011, and Phase II, involving permanent wells, was submitted on August 2, 2012. After that investigation, DEP agreed with the agency to defer further work while the company developed a plan for basin closure.[35] DEP also worked proactively with the Cape Fear Public Utility Authority ("CFPUA") to address its concerns about the possibility of migration of constituents from the ash basins to CFPUA's water supply wells. In 2013, CFPUA detected boron in its well. Based on the Phase I and Phase II investigations, CFPUA became concerned that boron was travelling to its well from the Sutton ash basins, contacted the Department, and proposed to install additional monitoring wells on [DEP] property. In response, [DEP] acknowledged the concerns and worked with CFPUA to remove the water supply wells from service and connect to an alternative water supply line. Subsequent investigation has indicated that boron is not travelling from the pond in the direction of the well, but [DEP's] timely action in this case reassured members of the public about the quality of their water supply, avoided a dispute over data interpretation, and preserved a positive relationship with a neighboring utility. Consistent with its history, the [C]ompany took targeted action to resolve a specific concern.

(Tr. vol. 19, 170-71.) These are the facts. Witness Wells, who was cross-examined and questioned extensively by Intervenors and Commissioners, received not a single

[35] See DEP Late-Filed Ex. No. 3, at PDF p. 10-11: "The current [i.e., 2009, which is when the document quoted from was submitted] ash pond at the Sutton Plant will reach full capacity on or before 2014. As mentioned earlier, [DEP] anticipates mercury emission-reduction requirements, SO_2 and NOx emission-reduction requirements and GHG regulation in the 2015-2017 timeframe. As a result, the 2014 date will allow [DEP] to avoid significant investment in environmental controls on the existing units, avoid additional coal ash-removal costs caused by continued operation, and reduce CO_2 compliance costs." (See also pp. 56-57, below.)

question about the Company's proactive response to the potential for boron migration beyond its 2L compliance boundary, nor its pro-active engagement with a water utility to address a perceived problem that ultimately turned out not to be caused by DEP.

In sum, and as witness Williams noted, this is how a "prudent utility" acts. (Tr. vol. 19, 654.) Intervenors are simply unable to refute her expert observation.

4. Viable Alternatives – Early Ash Pond Closure

The prudence framework demands a comparison between viable alternatives; without that comparison, the Commission is not in a position to assess whether the alternative chosen was imprudent. In addition, quantification of effect cannot be ascertained without a comparison of alternatives, since the disallowance must be calculated as the difference between the (presumably) higher cost imprudent alternative and the (presumably) lower cost prudent alternative.

Intervenors posit that regulatory closure of ash basins at an earlier (although undefined) point in time might have lessened current CCR Costs. Of course, "might have lessened" is not quantification.[36] In addition, wet sluicing of coal ash is the lowest cost option. (See DEP Late-Filed Ex. 21, at 1.) Accordingly, had the Company embarked prematurely upon dry ash handling at its facilities it would once again have opened itself up to "credible claims of 'gold-plating,' and therefore cost disallowance" (2018 DEP Rate Order, at 183), particularly in light of the Company's own conclusion – concurred in by DEQ – that no significant impact from the basins existed, in light of EPA/Arthur D. Little's identical conclusion (Joint Ex. 10, at iii), and in light of EPA's

[36] The same factors that the Commission pointed to in the 2020 Dominion Order would also apply. To support a disallowance, the Commission would need evidence of savings resulting from early closure netted against the costs that would have been incurred in early closure, including cost recovery plus a return on DEP's increased rate base. (See p. 37, above; 2020 Dominion Order, at 129.)

conclusion that existing coal ash management techniques were adequate. (Joint Ex. 13, at 7-11.)

Of course, responding to site-specific conditions, the Company did undertake dry ash conversions in limited circumstances. At its Roxboro facility it converted to dry fly ash handling in the late 1980s, in order to address surface water impacts to Hyco Lake (see Tr. vol. 19, 178); DEC did so too at its Belews Creek facility in the same timeframe and for essentially the same reason. (Joint Ex. 11.) This is an example of the Company acting proactively and prudently as warranted by evidence of environmental impact from its operations. (Tr. vol. 19, 686.) Dry fly ash handling capability was implemented at Mayo in order to take advantage of opportunities to sell the ash commercially (Bednarcik Rebuttal Sierra Club Cross Examination Ex. No. 2 (Mayo EIS), at 6-12.)[37] But in the case of both Roxboro and Mayo, bottom ash continued to be handled wet – because wet sluicing was not perceived to be an environmental risk, and because wet sluicing was not only the low cost option but also an entirely legal option, even according to Intervenors' own witnesses. (See p. 42, above.)

Prior to approximately 2010, the prevailing assumption in the utility industry was that coal-fired power plants would continue to supply power long into the future, on the order of 55 to 65 years. (Tr. vol. 17, 49-50.) In the 2009-11 timeframe, electric utilities with coal-fired plants were evaluating potential retirement of those plants because of tighter environmental regulation coupled with the falling price of natural

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[37] The Mayo EIS further demonstrated that wet fly ash handling was considerably cheaper than dry handling, with dry handling shown to be more than twice as expensive. (Mayo EIS, at 6-12; Tr. vol. 19, 682-83.)

gas. (Id.) The Company participated in this re-evaluation – as did the Commission itself. (See DEP Late-Filed Ex. No. 3.) In this Exhibit, DEP recounts the history of its planned retirements of coal units at its H.F. Lee, Cape Fear, and Weatherspoon plants in connection with the Commission's approval of a CPCN for a new 950 MW Wayne County Combined Cycle Project (Lee CC). These retirements were prompted by extensive analysis showing that required environmental controls at these units would be uneconomical and that retirement was the more cost-effective, and hence more prudent, path.

The Exhibit also notes the Company's request for – and the Commission's approval of – retirement of Sutton coal units in connection with the development of a replacement 620 MW combined cycle plant at Sutton (Sutton CC). Again, retirement was the more cost-effective and more prudent path, as opposed to installing newly required pollution control equipment.

The retirements all took place during the 2011-13 timeframe. Intervenors suggest that had ash basin retirement occurred in conjunction with plant retirement costs might have been lower – although, once again, they do not quantify "lower." But this notion also runs up against the "viable alternative" factor embedded in the prudence framework. In North Carolina, pre-CAMA and pre-CCR Rule, despite years of trying, the DEQ had simply not come up with closure rules, standards, and regulations.

The evidence of this is again completely undisputed, and was testified to at length by Company witness Jessica Bednarcik. (See Tr. vol. 13, 61-63; Bednarcik Direct DEP Redirect Ex. 3 (Redirect Ex. 3); Bednarcik Direct DEP Redirect Ex. 4 (Redirect Ex. 4).)

Redirect Ex. 3 is a memorandum memorializing a July 23, 2009 meeting between DEQ, DEP, and DEC regarding ash ponds. It starts out by indicating that DEQ had so far that year "received and responded to many questions from the media and the public about ash ponds," and that DEQ "staff had commended the utility companies for volunteering this groundwater monitoring program[38] and maintaining a productive working relationship with the agency." (Id. at 1.) The memorandum indicates that while DEQ had some pond closure requirements, they were "light on specifics" and that its two relevant subdivisions "would get together internally to discuss closure requirements for ash ponds." (Id. at 2.) It indicates further that DEQ did not state a timeframe by which it "would issue closure requirements for ash ponds." (Id.)

Redirect Ex. 4 is an email chain dated March/April 2013 between DEQ and "Duke Energy" (that is, after the merger of Duke and Progress, which occurred in July 2012). The email exchange reflects that in March 2013 DEQ sent Duke draft ash pond closure guidance developed "over the past year" and requested "feedback from our stakeholders, Duke and the former Progress Energy, before going forward with this." (Redirect Ex. 4, at 1.) The transmittal email also indicates that the DEQ draft "was based on what you [i.e., Duke] presented during our Weatherspoon closure meetings …." (Id.) The requested feedback was provided in April. (Id.) Of course, this exchange took place almost four years after DEQ had indicated, in Redirect Ex. 3, that it would come up with guidelines, although without any commitment as to a timeframe in which it would do so. As witness Bednarcik observed, this was not a

[38] The USWAG Action Plan's voluntary monitoring program, see p. 53, above.

“simple process” and it took “a long time … for DEQ to provide draft guidance.” (Tr. vol. 13, 63.)

The guidelines were never finalized. (Id. at 64.) Instead, with the passage of CAMA and the promulgation of the CCR Rule, the General Assembly and EPA provided highly prescriptive rules for how and in what timeframe basin closure could and would proceed.

The prudence framework requires the Commission to compare alternative choices available to the Company if it is going to deem the chosen option to be imprudent. But in terms of early closure of ash ponds, closure at any time prior to CAMA/CCR Rule was not even an option, unless the Company wished to get ahead of its environmental regulator, and simply begin to close a pond without that regulator’s buy-in. But that would have been imprudent – because without the buy-in, the Company had no assurance that its chosen path would have been approved by the environmental regulator. If not approved, then of course the Company would have been at risk of re-doing work – potentially very expensive work – it had already done. As witness Bednarcik stated, regulatory clarity ensures that the Company can execute its “work per our rules and regulations.” (Tr. vol. 13, 65.) Prematurely executing work and finding itself in non-compliance with the rules and regulations would have garnered no sympathy from the Public Staff, the AGO, or the Commission – its economic regulator.

Further, prematurely performing work in the timeframe after the publication by EPA of its proposed CCR Rule (Proposed Rule) in 2010 would have been even more fraught.[39] The scope of potential regulatory action set out in the Proposed Rule was very wide, so the issuance of the Proposed Rule increased, rather than decreased, regulatory uncertainty:

> The proposed rule offered regulatory options that varied significantly in how they would address existing ash ponds. One of the options would regulate CCR as a special waste under the hazardous Subtitle C regulations (the Subtitle C Option). Existing ash ponds would be required to meet similar requirements to hazardous waste surface impoundments or go through formal closure. Another option would establish standards for ash ponds under the non-hazardous Subtitle D regulations (the Subtitle D Option). Under this option existing ash ponds would also need to meet new technical standards, including composite liners, or close. However, EPA also offered a third option it called "D prime." This option was the same as the Subtitle D option, except that existing unlined ash ponds would not have to close or install composite liners but could continue to operate for their existing life. Therefore, the proposal left open whether existing ash ponds would be required to upgrade or close or could continue to operate as is and whether CCR would be regulated as a hazardous waste or as non-hazardous waste.

(Tr. vol. 19, 248-49.) Had EPA chosen the Subtitle C Option, the impact – in terms of what would have had to have been done and its cost – would have been "unbelievable"; in contrast, the D Prime Option would have meant the Company would "basically do nothing." (Id. at 573.) Guessing wrong could have led the Company to incur substantial costs and be subjected to second-guessing by the Public Staff, the AGO, and the Commission.

The Commission addressed this very point in the Company's prior case:[40]

> DEP in the past contemplated a future requirement to close unlined impoundments. While it was reasonable and appropriate to anticipate and plan for what EPA's ultimate decisions would be, the Commission determines not to penalize DEP through denial of cost recovery for its decision to wait until EPA's CCR determinations in this area were

[39] This of course is the precise timeframe in which Intervenors, citing retirement of coal plants, indicate that basin closure should have occurred.
[40] So, yet another "*déjà vu* all over again" moment.

> finalized. Had DEP acted prematurely in anticipation of regulations under consideration but not yet implemented, with the expenditure of substantial sums in the process, and with the ultimate EPA decisions differing from those anticipated, DEP risked unjustified expenditures.

(2018 DEP Rate Order, at 200.) The Commission even provided an example of how that might happen. It referenced EPA's 2015 promulgation of the Clean Power Plan, which imposed significant obligations upon the utility industry. The Commission noted that had "electric utilities incurred costs prematurely to comply, these costs could have been called into question when the U.S. Supreme Court stayed the Clean Power Plan." (Id. at 200-01.)

The danger of proceeding prematurely is also illustrated by Georgia Power's decommissioning of one of its coal-fired stations, Plant Arkwright. Closure also included the plant's coal ash ponds, which, like DEP's ponds, were unlined. The AGO introduced as a cross examination exhibit a 2004 manual published by the Electric Power Research Institute (EPRI) titled "Decommissioning Handbook for Coal-Fired Power Plants" (Doss/Spanos/Riley Rebuttal AGO Cross Exhibit No. 1 (2004 EPRI Manual)), which described the Plant Arkwright closure.

Ash pond closure at Arkwright was prompted not only by closure of the associated coal plant (something not contemplated for DEP plants until much later), but also by Georgia Power's desire to repurpose the plant site "for future development." (Id. at A-2.) Ash pond closure in Georgia had a defined regulatory structure, and the Georgia environmental authorities participated in the closure plan. (Id. at A-6.) Nothing similar was available to DEP in North Carolina.

But the Plant Arkwright pond closure serves as a cautionary tale, as its story was not finished in the mid-2000s. Despite the involvement of the Georgia environmental authorities in the closure, and despite the fact that Georgia had a defined regulatory structure for pond closure, Georgia Power is today having to re-do the closure, because the regulatory standards have changed from the time at which the work was originally performed. (Tr. vol. 19, 707-08.) The notion that early closure would necessarily have resulted in lower (if still undefined) cost has no basis in objective evidence and is sheer speculation.

Company witness Williams, drawing on her decades of experience, testified that in light of all the regulatory uncertainties faced by owners and operators of coal ash ponds in North Carolina, it was prudent to wait "until after CAMA and the CCR Rule became law to take specific actions to upgrade or close ash ponds as long as they were working cooperatively with environmental officials to address any site-specific environmental issues." (Tr. vol. 19, 213-14.) No Intervenor witness has the credentials to credibly contradict this testimony, and no Intervenor witness did contradict this testimony.

DEP did intervene and work cooperatively with environmental officials to address site specific environmental issues. Witness Wells testified, if the Company were to see a public health risk then "You move and take action. And that's what the Company has done throughout these years." (Tr. vol. 19, 384.) One example of this is the Sutton chloride situation in the mid-1980s (see pp. 43-44, above); another is the Roxboro Hyco Lake situation (see p. 56, above); and yet another is the Sutton boron plume situation (see pp. 54-55, above). But apart from these discrete instances the Company did not see a public health risk justifying precipitous action – and neither did its environmental regulator, DEQ. As witness Wells testified, the Company's ash basins have been actively regulated by DEQ for decades in order to "minimize potential impacts to human health and the environment," including reviewing "decades-worth of surface and groundwater data" from those basins. (Tr. vol. 19, 181.) Despite this intensive regulation, prior to the advent of CAMA/CCR Rule and their new legal requirements, DEQ never ordered DEP to cease using or close the basins, and never even took other less sweeping measures, such as requiring the Company to retrofit the basins with liners, close basins that had become inactive, or excavate coal ash from any basin, active or inactive. (Id.)

DEQ's regulatory role is ignored by Intervenors. But fully appreciating that role is critical to the prudence analysis. Witness Williams testified:

> That DEQ did not require [DEP] to modify the design of its ash ponds by requiring liners, did not require the ponds to close, or did not mandate groundwater monitoring earlier than they did, is a strong indication that [DEP's] operations were considered to be reasonable and protective by the Agency charged with protecting the North Carolina environment.

(Id. at 277.) CAMA and the CCR Rule require highly prescriptive actions that the Company is compelled to take, and which it has taken. The notion that in the absence of those prescriptive requirements, and in the absence of a perceived risk of environmental harm, DEP should have taken those or similar actions earlier, and that doing so would have reduced cost, also has no basis in objective evidence and is sheer speculation.

5. Intervenors Attack on the Company's Historical Practices Betrays 20/20 Hindsight and Lack of Rigorous Analysis, both of which are Prohibited by the Prudence Framework

The prudence framework expressly forbids the Commission from evaluating a utility's conduct through the eyes of hindsight, which, of course is always 20/20: "Hindsight analysis – the judging of events based on subsequent developments —

is not permitted." (1988 DEP Rate Order, at 14.) Unfortunately, however, Intervenors' testimony and arguments are infused with hindsight analysis.

Illustrating this point to perfection is the DEC testimony of Public Staff witness Junis.[41] He expressed his concern, in commenting on witness Bednarcik's testimony (Tr. vol. 12, 242), that in her review of some of the historical EPRI Manuals she tried to put herself in the timeframe of the documents (1981 and 1982) with the knowledge available at that time, and with that mindset concluded that she would not have done anything differently at the time. He stated in response:

> [Witness Bednarcik] stated very authoritatively that, based on reviewing all of this historical documentation, that if she was in a position to decide, she would have done nothing different in the management of coal ash over that period. ***I have great concerns about a scientist or engineer looking back over decades of time and not finding one thing that could have been done better or differently.***

(Tr. vol. 15, 1726-27) (emphasis supplied).) This is the Public Staff's philosophy – looking back, it could find all manner of things that in its view should have been done differently. But that, in a nutshell, is hindsight analysis. Witness Bednarcik, to the contrary, engaged in appropriate prudence review analysis – she sought to review decisions made in 1981 and 1982 "in light of the facts known at the time the decision was made" (Lesser & Giacchino, at 40), not looking at those decisions with 20/20 hindsight.

As we have seen already (see p. 50, above) Lucas' overall criticism that the Company should have engaged in "comprehensive" groundwater monitoring in the

[41] This testimony has been stipulated into the DEP Record through the Amended Stipulation, which recognized "that a question posed live in the [DEC] hearing to a witness in that hearing would be answered in like fashion by that same witness, tailored to [DEP], in the [DEP] hearing." (See fn. 13, above.)

1980s (Tr. vol. 15, 1480-81) is another example of Intervenors' hindsight analysis; as witness Williams testified in response, it was not until "many decades later, that we understood that it takes a very large number of wells to truly understand the complexity of what's going on in the subsurface adequately." (Tr. vol. 19, 716.) She responded further to witness Quarles' testimony regarding groundwater monitoring standards and his criticism of what EPA and the utility industry knew about groundwater monitoring in the 1980s, noting first that she was "somewhat disturbed by his comments" (Tr. vol. 19, 701) and continuing:

> [Witness Quarles] also expressed the opinions strongly about the state of groundwater monitoring and whether that monitoring was required by EPA. He didn't cite references in his response, nor were there supporting references in his testimony on that. And I would just say, again, I lived this for a very long time at EPA. And I will tell you that groundwater monitoring was very different in terms of the knowledge level in the 1980s than what it is today.
>
> And that included things like the definition of what a perched aquifer was that was defined as part of the uppermost aquifer. But it also included whether or not groundwater monitoring on a site-specific basis was deemed to be high priority and appropriate. And it was specifically deferred to the state to make those determinations.

(Id. at 704.)

Witness Williams was with EPA from 1970 through 1988. (Id. at 701.) In her own words, quoted above, she "lived" these issues. She knows exactly when Intervenor witnesses are employing hindsight analysis because she was there at the time and understands and knows from her own first-hand experience what was happening at the time. And her conclusions based upon her vast experience and expertise fully support the Company's positions:

- First, that it is difficult to predict the exact nature of future regulatory requirements until a final rule has been issued.

- Second, that owners and operators of coal ash basins in North Carolina faced significant uncertainty regarding the regulatory requirements for managing CCR until the passage of CAMA and the promulgation of EPA's final CCR rule, and even after these new legal requirements were finalized site-specific clarity for the Company was achieved until 2020.

- Third, in light of these uncertainties, owners and operators of coal ash ponds were acting prudently by waiting until after CAMA and the CCR rule became law to take specific actions to upgrade or close ash ponds as long as they were working cooperatively with environmental officials to address any site-specific environmental issues.

- Fourth, prior to the enactment of CAMA and promulgation of the final CCR rule, an accurate estimate of the costs associated with ash pond closure (even assuming that closure would have been required) would have been extremely difficult with a high likelihood for significant over- or under-estimation. Even with those regulations, fully known and measurable estimates required completion of recently finalized site-specific closure agreements.

(Id. at 234-35.) Intervenors simply have not presented evidence to refute witness Williams' observations; to the contrary, through her testimony the Company has met its ultimate burden of proof to show that its historical actions were prudent and do not form the basis of any cost disallowance.

Perhaps in recognition of the weakness inherent in Intervenors' reliance upon hindsight analysis, Sierra Club attempted in the DEP-specific hearings a different tack. During its cross-examination of witness Bednarcik it introduced the Mayo EIS. (Bednarcik Rebuttal Sierra Club Cross Examination Ex. No. 2.) After witness Bednarcik, recalling her DEC testimony, noted that Intervenor witnesses "were putting [on] today's lens" when they tried to look at historical practices, and that is what she "was calling out" (Tr. vol. 17, 480-81), Sierra Club asked if she was "aware that, in 1978, at the time the Company was making decisions, EPA had clearly stated that water carriage of fly ash and bottom sluicing systems are, quote, inconsistent with existing and expected standards of performance for new sources." (Id. at 481.)

The quoted reference in the question was to a few lines in a letter within the 500+ page Mayo EIS, which points to an Intervenor tactic very much akin to hindsight analysis – cherry picking a line or two from a historical document and using the cherry-picked "evidence" to seek to prove a point. The prudence framework demands rigor; in the Commission's own words, a "detailed and fact intensive analysis." (2020 Dominion Rate Order, at 116; 2018 DEC Rate Order, at 258.) Cherry picking is the antithesis of rigor, and this is demonstrated by rigorous examination of the Mayo EIS itself, which the prudence framework requires.

Rigorous analysis begins with context. An Environmental Impact Statement is required under the National Environmental Policy Act (NEPA), 42. U.S.C. § 4321 et seq., which "sets forth a regulatory scheme for major federal actions that may significantly impact the environment." *Nat'l Audubon Soc'y v. Dep't of the Navy (Audubon)*, 422 F.3d 174, 184 (4th Cir. 2005). The Mayo EIS was made necessary by DEP's application for a permit (404 Permit) from the Army Corps of Engineers (Corps), a federal agency, in connection with the development of the Mayo plant. The Corps was, therefore, the federal agency that prepared the Mayo EIS. The process culminated in the issuance by the Corps of the 404 Permit. (Mayo EIS, at PDF pages 1-11.)

NEPA is designed "to promote efforts which will prevent or eliminate damage to the environment and biosphere and stimulate the health and welfare of man." *Audubon*, 422 F.3d at 184. It does so in two ways – first, it requires that the federal agency in question (here, the Corps) carefully consider the effects of its action upon the environment – in NEPA parlance, that the agency take a "hard look" at the action's environmental impact. Id. at 184-85. Second, NEPA requires the agency to communicate widely so as to ensure that the public and other governmental agencies have the opportunity to analyze and comment on the proposed action. Id. at 184. To fulfill this obligation, the agency in question will prepare and disseminate a Draft Environmental Impact Statement (Draft EIS). In the Mayo Draft EIS, one of the issues identified by the Corps was a "potential risk to Crutchfield Branch" in connection with the development of the Mayo project. (Tr. vol. 19, 680.)

The entire Mayo EIS document consists of well in excess of 500 pages. Two of those pages consist of a comment letter from EPA Region IV to the Corps, commenting on the *Draft* Mayo EIS. (Mayo EIS, at PDF pages 498-99.) The snippet from the letter referenced in Sierra Club's cross-examination of witness Bednarcik came from this letter. EPA Region IV noted therein its concern, echoed in the cross-examination, regarding the potential environmental impact to Crutchfield Branch, a stream nearby the proposed location of the ash pond and into which the proposed NPDES outfall from the pond would flow.

Following receipt of comments, the next step in the NEPA process is for the Corps to review and resolve the comments, which the Corps did in connection with its preparation of the *Final* Mayo EIS. (Tr. vol. 19, 680.) Witness Williams described in detail the Corps' resolution of the EPA Region IV comments. (Id. at 696-700.) She testified that in the Final Mayo EIS, those comments were indeed addressed:

> And one of the key aspects about the final statement is that it said the final EIS had looked at all of the issues that had been raised with regard to groundwater and the ability of groundwater potentially to impact Crutchfield Branch. And the solution to that, which was laid out in the final EIS, was that it would be addressed through the NPDES permit …. And, in fact, that's what happened.

(Id. at 696.)

Thus, the Corps, in accordance with the NEPA process, received comments from, among others, EPA Region IV. It also received input and comment from other agencies, including DEQ. The DEQ comments were repeated by the Corps in Section 2.2.2 of the Mayo EIS, in which the Corps addressed groundwater concerns related to the Mayo project. The DEQ comments indicated, first, that the Company would be required to complete groundwater studies related to the potential for environmental impact. (Mayo EIS, at 2-6.) The Company did so – it commissioned the Floyd Report (see pp. 48-49, above), which concluded that "it is difficult to imagine that any significant adverse impact on the ground water aquifer could be caused by ponding of the ash wastes at the proposed site." (Floyd Report, at 15.) The DEQ comments further indicated, as witness Williams testified, that all discharges to Crutchfield Branch would be covered by the NPDES permit for the ash pond, and that the permit also provide for testing to ensure no impact upon Crutchfield Branch. This, too, was done. The NPDES permit was issued (Tr. vol. 19, 698-99), and surface monitoring of Crutchfield Branch was written into the original NPDES permit in 1982 and each subsequent permit in order to confirm that any groundwater impacts were not being realized in that surface water stream. (Id. at 674-75, 699).

The DEQ comments concluded by indicating DEQ believed "that by including this language in the NPDES permit for the Mayo project sufficient controls will be available to assure that examination of potential groundwater pollution is completed and that appropriate remedial action is taken by the Company prior to the completion of the project." (Mayo EIS, at 2-6.) Witness Williams, testifying from the EPA perspective, concurred. She expressly disagreed with Sierra Club's characterization of EPA Region IV's comments:

> But secondly, and I think really importantly, the EPA Office of Solid Waste[42] continued to look at this whole issue of whether or not unlined ponds were protective throughout the 1980s, as I had mentioned earlier today, and also looked at the question of groundwater monitoring, and continued to find both unlined ash ponds and the need for groundwater monitoring to be site specific, and … found them to be the industry standard and not unreasonable with respect to impacts on groundwater through the 1980s. And you can even take it beyond that, because EPA did not really make its determination [regarding unlined ash ponds] until it finalized the CCR Rule in 2015.

(Tr. vol. 19, 700.) Thus, rigorous – as opposed to surface – analysis of the Mayo EIS would reveal that, first, the final conclusion of the entire study was that the ash ponds at Mayo would not have a significant environmental impact, and, second, that the manner in which the agencies charged with protecting the environment would assure this outcome would be through the NPDES permitting process. The Sierra Club's attack on the Company using a couple of lines from a single set of comments does not comport with rigorous analysis.

Intervenors' inability or unwillingness to avoid hindsight analysis makes their testimony unreliable and untrustworthy. The Commission should not credit this testimony and should disregard it when assessing the Company's conduct under the prudence framework. Further, while Intervenors may, in their roles as partisan advocates, avoid rigorous analysis of historical documents in an effort to score points, the Commission is not a partisan advocate – on the contrary, it is a neutral administrative body charged by the Legislature with setting rates that are just and reasonable, fair to both the utility and its customers. It cannot fulfill that mandate

[42] Importantly, not the regional office, but instead the EPA Headquarters office of which witness Williams became Director and which produced the 1988 EPA Report to Congress (Joint Ex. 13).

without rigorous analysis of the historical documents introduced by the parties and without the avoidance of partisan advocacy.

II. DEP IS ENTITLED TO A RETURN "ON" THE UNAMORTIZED BALANCE OF DEFERRED COAL ASH COSTS AS THOSE COSTS ARE BROUGHT INTO RATES DURING THE AMORTIZATION PERIOD

DEP seeks a return, at its weighted average cost of capital (WACC),[43] on deferred CCR Costs during two distinct periods: the Deferral Period and the Amortization Period, both defined herein.

The Deferral Period is the period from the time the costs were first incurred through the date upon which they begin to be brought into rates; for purposes of this case the return applies to the period through August 31, 2020. As it did in the Company's prior rate case, the Public Staff supports a WACC return in this period. (Tr. vol. 15, 1555.) The Commission approved such a return in the Company's last rate case, in DEC's last rate case (Docket No. E-7, Sub 1146), and in Dominion's last rate case (Docket No. E-22, Sub 562).[44] Thus, DEP will not further address a return on CCR Costs during the Deferral Period in this Brief; suffice it say that the reasons that a return is required during the Amortization Period apply equally to the Deferral Period.

[43] Company witness Sean Riley indicated that in the case of CCR-type costs, the "default" rate of return is the weighted average cost of capital (Tr. vol. 13, 406), which of course is necessarily true in order to compensate both debt and equity investors for the use of their capital.

[44] In the Dominion case the Commission observed that "such a return may reduce the incentive for [Dominion] to apply for rate increases more frequently to avoid regulatory lag." (2020 Dominion Order, at 135.) That "may" apply to Dominion. Its CCR cost recovery request on a system basis was $377 million, but only $21.8 million of that amount was allocated to North Carolina retail jurisdiction. (Id. at 86.) The rest was allocated to Virginia – a jurisdiction which permits recovery "of" and return "on" CCR costs. (Tr. vol. 4, 37.) By contrast, the Company estimates its CCR costs will be in the hundreds of millions of dollars per year in the relatively near term, and billions of dollars overall. So long as spend/defer/recover continues as the operating model, it will be forced to file frequent rate cases regardless even though a return on CCR costs is allowed the during the period of deferral.

The Amortization Period is the period over which deferred CCR Costs are amortized – that is, paid by customers over time – as they are brought into rates.[45] By definition, the CCR Costs to be recovered by the Company during the Amortization Period are prudently incurred – had they not been prudently incurred, the Commission would simply disallow them, and we would not then be facing any issue of a return "on" such disallowed costs.

The unamortized balance thus represents a loan by the Company to its customers. Under the spend/defer/recover model, prudently incurred CCR Costs were advanced by the Company to its customers, and are being paid back over time by its customers. Loans bear interest – the interest is the financing cost, the cost of the money borrowed. The return sought by DEP during the Amortization Period is synonymous with and equivalent to the cost of financing the unamortized balance of CCR costs – the return is the cost of money. As DEC witness Jane McManeus testified response to questions from Commissioner McKissick:

> [W]e use a number of terms when we're talking about this interest or return. Sometimes we call it the cost of money, sometimes we call it weighted average cost of capital, [sometimes] we say it's a debt and equity return, [but] it's [all] financing costs.

(Tr. vol. 13, 314.)[46]

[45] The approved Amortization Period in the Company's last rate case was five years, and the Company proposes a like period in the current case. While the Public Staff disagrees with the five-year period proposed, it agrees that amortization over some multi-year period is appropriate. (Tr. vol. 15, 1552-53.)

[46] On September 25, 2020, the Company and the AGO filed a Joint Stipulation (Joint Stipulation) in which the stipulating parties agreed that, subject to the Commission's approval, the testimony of witness McManeus in the DEC-specific hearings could be entered into the record in this case as if given by DEP witness Kim H. Smith. Witness Smith affirmed that she agreed with the stipulated testimony, and had no objection to the answers given by witness McManeus. (Tr. vol. 13, 283-84.)

Were the Commission to deny DEP a return on the unamortized balance of CCR Costs during the Amortization Period, it would convert the loan made by the Company to its customers from an interest-bearing loan to an interest-free loan. Forcing the Company to make an interest-free loan to its customers under the circumstances of this case would be unlawful.

The Commission recognized in DEC's last rate case that to deny a return upon the unamortized balance would be unlawful. (DEC Order, at 290 (denying the return would impair the Company's ability to earn its authorized return and "[r]ates that impair the Company's ability to earn its authorized return are not just and reasonable … and the Commission would act contrary to law were it to order them.").) The facts and circumstances which led the Commission to that conclusion apply equally to this case, and the conclusion still holds. What is different today are the expectations created by that decision as well as the Commission's decision in the Company's own prior case.

In the last round of rate cases for DEC and DEP, the Commission was writing on a blank slate. Coal ash cost recovery had not as yet been dealt with by the Commission in a fully litigated case. Both the prior DEC case and the prior DEP case were, however, fully litigated with respect to the issues of coal ash recovery and a return thereon. In DEP's case, the Commission allowed almost full recovery of coal ash costs at issue, based on its finding that those costs had been prudently incurred.[47] It further awarded full recovery (less a cost of service penalty) of a return on the unamortized balance of those costs as they were brought into rates during the

[47] The Company's cost recovery request was approximately $242 million; the Commission disallowed $9.5 million. (2018 DEP Rate Case Order, at 18.)

Amortization Period. But the Commission went further. Rejecting an alternative cost recovery model (the "run rate") proposed by DEP, it held that "instead" DEP would be required to keep to its spend/defer/recover model of cost recovery, and that in the Company's next general rate case (i.e., this case) the Commission would undertake its prudence review of coal ash costs and "unless future imprudence is established, … [the Commission would] permit earning a full return on the unamortized balance." (2018 DEP Rate Order, at 206.)

The "spend" in spend/defer/recover represents funds advanced by the Company's investors. No investor advances funds without an expectation of a return. The promise embedded in the Commission's decision to require continued adherence by the Company to spend/defer/recover highlights even more that a Commission decision to deny the return in this case would be unlawful. Denial of an investment backed expectation is the foundation of a constitutional "takings" claim. *Penn Cent. Transp. Co. v. New York City*, 438 U.S. 104 (1978).

Simple fairness also must be factored into the equation. As witness McManeus testified, "[W]hen I think of what the Company's requesting, I think of it in terms of being made whole, and being made whole in terms of cost." (Tr. vol. 13, 315.) DEP cannot by definition be "made whole" if a significant cost (the cost of money) is disallowed in the same decision in which the underlying costs being financed are found to have been prudently incurred, and, therefore, are recovered – but recovered, as a rate mitigation measure to help customers, over time. Money is not free; to the contrary, it has a cost (Tr. vol. 13, 200, 207, 281-82), which no one disputes.

But fairness is not simply a matter of equity; it is also a legal requirement. Under N.C. Gen. Stat. § 62-133(a) rates set by the Commission must be fair to both the Company and its customers. Forcing the Company to make an interest-free loan to its customers can hardly be said to be "fair" to the Company. That is what also makes it illegal under N.C. Gen. Stat. § 62-133(a) and confiscatory under *Bluefield*/*Hope*.

In DEP's last rate case the Commission noted that the Company and the Public Staff had engaged in a dispute over whether a return "must" or merely "may" be allowed, with the Company advocating "must" and the Public Staff advocating "may." (See Order on Motion for Clarification, Docket No. E-2, Sub 1142 (April 17, 2018) (Clarification Order), at 3-4.) The Commission determined that it was unnecessary to decide this issue. (Id.)

This same debate played out in DEC's last case, and included a further controversy between the Company and the Public Staff on the appropriateness and effect of the ARO accounting employed by both DEC and DEP in their prior cases, and both DEC and DEP in their current cases. DEC's testimony and argument in its prior case showed that it appropriately accounted for CCR Costs in AROs, and that pursuant to the ARO accounting rules those costs were capitalized and therefore should bear a return. The Public Staff took the position that the costs, even if accounted for in AROs, were deferred expense, and, therefore, a return was not required. Here, while indicating that the Company's position was correct and supported a return, and that the Public Staff's position was "not persuasive, not supported by authority and not determinative … [and] also incorrect as a matter of accounting," the Commission again determined that this was an issue unnecessary to resolve. (2018 DEC Rate Order, at 289.)

Instead of resolving these issues in the prior cases, the Commission opted to award a return in the exercise of what it asserted to be its discretion. (Clarification Order, at 3; 2018 DEC Rate Order, at 275-76.) Because the Commission chose not to directly resolve this issue in the Company's prior case, the "*déjà vu* all over again" quality of this case applies not only to the recovery "of" issues but also to the return "on" issues. However, were the Commission to again decide not to directly address the issue of whether it "must" allow a return on the unamortized balance of CCR Costs during the Amortization Period, the Commission may nevertheless do what it did in the Company's last case, as well as DEC's last rate case, and exercise its purported discretion to allow a return, based on either or both of two principles. First, it could – and should – decide that allowing the return is the right thing to do to ensure that it fulfills its statutory mandate to set just and reasonable rates, fair to the utility and to the consumer. That is what the Commission did in the Company's prior rate case.[48] Second, it could – and should – recognize that what it did in the Company's prior rate case, and the manner in which it decided the issues in the prior case, created investor expectations of a return "on" in this case. Failing to do so is nothing less than an attack upon the regulatory compact that underlies rate regulation in North Carolina and across the entire country.

[48] DEP recognizes of course that the 2018 Order is on appeal. But the core holding of the Commission with respect to the issue of a return on CCR costs is that it possessed the discretion to award a return, and in the exercise of that discretion would award one on the unamortized balance of CCR costs during the Amortization Period. For the Supreme Court to reverse that holding would require it to decide that the Commission had somehow abused its discretion – a tall order, particularly for the Public Staff, inasmuch as the Public Staff agrees that the Commission has discretion to award or not award the return. (See Tr. vol. 15, 1572.)

While the Commission of course "could" decide in the exercise of its discretion that a return is warranted, it "should" decide the issue as a matter of legal entitlement – because it *is* a matter of legal entitlement. DEP has a legal entitlement to recovery of the financing cost inherent in bringing prudently incurred CCR Costs into rates over time during the Amortization Period. Those Costs – the "spend" in spend/defer/recover – are "property used and useful" in the service of customers. Refusing to award the financing costs results automatically and as a matter of mathematics in impairment of the Company's earnings, which not only is prohibited by *Bluefield*/*Hope*, but in turn results in rates that are "unfair" to the Company in violation of N.C. Gen. Stat. § 62-133(a) and in violation of the Commission's mandate to set rates that are just and reasonable. Were it to refuse a return, the Commission would, in its own words, be acting "contrary to law." (2018 DEC Rate Order, at 290.)

A. The "Spend" in Spend/Defer/Recover is Investor-Supplied Capital, and is "Property Used and Useful" in Providing Service to Customers

Under the Public Utilities Act, the Commission must provide the utility with the opportunity, by sound management, to (1) produce a fair profit for its shareholders, in view of current economic conditions, (2) maintain its facilities and service, and (3) compete in the marketplace for capital. *State ex rel. Utils. Comm'n v. Gen. Tel. Co. of the Southeast*, 281 N.C. 318, 370 (1972). As the Supreme Court held in that case, these factors constitute "the test of a fair rate of return declared" in *Bluefield* and *Hope*. Id. These requirements are built into the rate-making statute, N.C. Gen. Stat. § 62-133. The rate of return deemed sufficient by the Commission to accomplish these ends is set in accordance with Section 62-133(b)(4), and the property to which the return is to be applied is measured in accordance with Section 62-133(b)(1), which states that the return is to be on "property used and useful, or to be used and useful within a reasonable time after the test period, in providing the service rendered to the public within the State."

The statute does not define the phrase "property used and useful." Intervenors appear to have a narrow, crabbed view of its meaning, asserting that "used and useful" property is confined to utility plant assets that generate, transmit, and distribute electricity. The Commission has already decided that this narrow interpretation is incorrect (2018 DEC Rate Order, at 290-91), and, indeed, witness Smith, quoting DEC witness McManeus, provides examples of non-utility plant assets that are nonetheless classified as property used and useful, such as reserve fuel and cash working capital. (Tr. vol. 13, 201.)

In *State ex rel. Utils. Comm'n v. Virginia Elec. & Power Co. (VEPCO)*, 285 N.C. 398, 414-15 (1974), the Supreme Court expressly recognized that when a utility keeps on hand a reasonable amount of shareholders' funds (in the form of cash) to pay operating expenses, such working capital constitutes property that is used and useful in providing retail electric service and should be included in rate base. The Court held:

> While Chapter 62 of the General Statutes makes no reference to working capital, as such, the utility's own funds reasonably invested in such materials and supplies and its cash funds reasonably so held for payment of operating expenses, as they become payable, fall within the meaning of the term "property used and useful in providing the service," as used in G.S. 62-133(b)(1), and are a proper addition to the rate base on which the utility must be permitted to earn a fair rate of return.

Id. Thus, to the extent that Intervenors continue to assert that "property used and useful" is limited to a utility's physical plant, that position is contrary to North Carolina law. Instead, under *VEPCO*, what stands as "property used and useful" does not turn on whether the property generates electricity, but whether it serves the public and was paid by debt or equity investors – rather than through rates that were set in anticipation of normal operating expenses.[49]

The CCR Costs DEP seeks to recover in this case were incurred as a result of the changes in law wrought by the CCR Rule (promulgated in 2015) and CAMA (initially enacted in 2014 and amended in 2016). On December 21, 2015, DEC and DEP submitted to the Commission and the Public Staff a letter (Savoy Letter, DEC Junis/Maness Cross Examination Ex. 4)[50] that outlined the spend/defer/recover model DEC and DEP would follow in connection with their incurrence of the costs and the recovery of those costs in rates. The Commission noted that "through the Savoy Letter the Company [indeed, both DEC and DEP, as the Savoy Letter was from both of them] told the Commission and the Public Staff, and the Commission told all interested parties" exactly how the program would work. (2018 DEC Rate Order, at 289.) No party objected to the Company's plan; indeed the Public Staff agrees that spend/defer/recover is the program in which the Company has been engaged, and that the program was outlined in the Savoy Letter and the subsequent formal deferral request submitted by DEC and DEP. (Tr. vol. 15, 1689-90.)

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[49] In DEC's prior case, the Commission noted that it appeared that the Public Staff "misunderstood" the Company's position on what constitutes "property used and useful." (2018 DEC Rate Order, at 290.) In this case, the Public Staff again misapprehends the Company's reliance upon *VEPCO* and its reference to working capital being "property used and useful." (Tr. vol. 15, 1575-77.) The Public Staff once again indicated in its post-DEC-specific hearing filings that the holding of the *VEPCO* case is limited to the Court's treatment of "working capital." The Public Staff's continued regurgitation of its "working capital" argument is yet another example of its willful blindness to the Company's actual – as opposed to imagined – positions.

[50] This exhibit is through the Amended Stipulation now a part of the record in this case. (Tr. vol. 15, 1817.)

To put CCR Costs into *VEPCO* terms, the “spend” in spend/defer/recover is “property” akin to the working capital that the Court held was properly counted as rate base, upon which a return was statutorily required. It is cash supplied by investors, just like working capital is cash supplied by investors.

It is completely undisputed that the spent and deferred CCR Costs which DEP seeks recovery of in this case were advanced by the Company’s investors, and are not included in current rates. DEP witness Smith so stated in her rebuttal testimony (Tr. vol. 13, 200), and witness McManeus reiterated it in response to questions from Commissioner McKissick:

> [T]he way I think about it is, when we have amounts that we spend, for example, on coal ash, that are not yet reflected in our rates -- so, for example, the 2018, '19 spend is not reflected in our rates … by definition, investors [both debt and equity] are advancing these funds.
>
> … So when we say we want a return, we're talking about total financing costs on these amounts that have been advanced, and it's made up of both debt and equity.

(Tr. vol. 13, 314-15.) No party submitted contradictory evidence, and Public Staff witness Michael Maness actually agreed. (See Tr. vol. 15, 1578 (“The utility has already spent the money represented by the deferred costs in question; therefore, it will be required to borrow the money or use equity to finance the spent costs until it can recover them from ratepayers.”).)

The “spend” in spend/defer/recover not only is “property” within the meaning of *VEPCO* and Section 62-133(b)(1), it is also provided in service to customers – the “spend” was made, and is continuing to be made, in order to comply with changes in the law; indeed, the Company does not have the option to *not* comply with changes in the law. (See 2018 DEC Rate Order, at 268-69 (“Capital expenditures undertaken to enable compliance with the law qualify as 'used and useful,' in that the Company does not have the option to fail to comply …").) Here, too, Intervenors have a narrow, crabbed view of the meaning of the words of the statute. Witness Maness indicates that CCR Costs (which is what the "spend" constitutes) relate "to service that was provided in the past," and which are "not really providing any additional benefits to customers in terms of additional electric service or improvements of service." (Tr. vol. 15, 1778-79.) But this makes no sense – the spend is occurring today as a result of changes in the law that came into being in 2014, 2015, and 2016.[51] But for the changes in law, there is no evidence whatsoever that the "spend" would be occurring at all. CAMA and the CCR Rule mandate basin closure – until they came into being, continued operation of the Company's ash ponds was entirely legal, and, as we have seen (see pp. 61-62, above), premature retirement could well have been imprudent and more expensive than the costs being incurred today. CAMA and the CCR Rule require the specific steps that the Company is taking to address and remediate groundwater contamination resulting from the normal operation of the basins. But for their prescriptive requirements, there is no evidence whatsoever that assessment

[51] In DEP's last case, the Commission rejected the Public Staff's "label-driven classification" of "used and useful," noting as a "concrete example" that the "spend" in that case included new landfills with new liners, capital items with service lives of in excess of one year. (2018 DEP Rate Order, at 195-96.) In DEP's current case, for example, its "spend" on a system basis through June 30, 2019 in connection with construction of the Cape Fear and H.F. Lee beneficiation facilities – a requirement of the 2016 CAMA amendments – was in excess of $106 million. (Tr. vol. 12, 51.) These facilities are essentially manufacturing plants designed to convert coal ash from the ash basins into a useable product in order to fulfill the reuse goals of CAMA as amended. The same considerations that drove the Commission in the 2018 DEP Rate Order to reject the Public Staff's "label-driven classification" apply with equal force in this case. Indeed, in light of examples such as the beneficiation projects, witness Maness' general classification of CCR Costs as "deferred expenses" is no less label-driven, and, as it did in DEC's last case (see fn. 52, below), the Commission should reject it.

and remediation of groundwater now being required would ever have been required under the law as it existed prior to CAMA and the CCR Rule.

In this case, Company witness Doss testified that the CCR Costs representing the "spend" funded by investors

> [A]re used and useful as those costs are reasonable and prudently incurred and are intended to provide utility service in the present or in the future through achieving their intended purpose: environmental compliance, the retirement of the ash impoundments and the final storage location for the residuals from the generation of electricity. The achievement of those three purposes is used and useful as the utility has the obligation to comply with CAMA and the CCR Rule.

(Tr. vol. 16, 344.) Witness Doss provided identical testimony in DEC's prior case. (DEC Order, at 257.) In DEC's prior case, the Commission credited his testimony, rejected the contrary testimony of witness Maness, who classified[52] the costs as "deferred expense" and therefore ineligible to even be counted as "used and useful," and found that the CCR costs that were the subject of the prior case were indeed "used and useful." (Id. at 292.) As the Commission held, quoting witness Doss, the achievement of CAMA/CCR Rule compliance and the other purposes of CCR spend "is used and useful as the utility has the obligation to comply with CAMA and the CCR Rule." (Id.)

Nothing has changed, and this is yet another "*déjà vu* all over again" moment – the Company and the Public Staff extensively debated the appropriateness and effect of ARO accounting in DEC's prior case, and the same evidence was again submitted in this case, from witness Maness for the Public Staff, and witness Doss

[52] In truth ***mis***-classified, as the Commission found as a fact that his position was "not persuasive, not supported by authority and not determinative … [and] also incorrect as a matter of accounting." (DEC Order, at 289.)

for DEP. The only "new" evidence came from Company witness Riley,[53] but it served merely to buttress from a national perspective what witness Doss testified to from a Company-specific perspective.

In DEC's prior case, and after extensive discussion of applicable accounting standards under GAAP and FERC standards, along with the Commission's own deferral standards, the Commission ruled

> While the accounting rules detailed herein are complex, in simplified terms, both GAAP and FERC accounting guidance require the recognition of a liability (the ARO) upon the requisite triggering event – the legal obligation to retire the Company's coal ash basins. Recognition of the liability carries with it recognition of a corresponding asset – ***the capitalized cost of settling the liability, which under both GAAP and FERC rules is considered part of the property, plant and equipment for the assets that must be retired***.[54] While under ordinary circumstances these recognition events would be reflected over time in the Company's income statements, because of the deferral order in Docket No. E-7, Sub 723, the income statement impacts are deferred into regulatory assets "pending further orders of the Commission." The Company in this case is seeking such a further order, so as to reflect in rates the outflow of cash that it has incurred – and that its investors have funded – as it proceeds to settle the asset retirement obligation created by the CCR Rule and CAMA.

(DEC Order, at 288 (emphasis supplied).) This is what witness Doss testified to in DEC's prior case, and what witnesses Doss and Riley testified to all over again in this case. (Doss: Tr. vol. 16, 409 (when Company records an asset retirement

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[53] In an apparent effort to manufacture something "new" witness Maness alluded to a data request response made by the Company that he indicates confirmed that "when the Company makes the deferral entries on its books, it isn't, in fact, deferring the GAAP ARO depreciation expense that it records for financial statement purposes." (Tr. vol. 15, 1669.) But witness Doss' testimony in DEC's prior case made perfectly clear that this was exactly how the Company's accounting worked (2018 DEC Rate Order, at 287), so this is not "new" in the least. In addition, as shown in DEP's Late-Filed Ex. 24 depicting the life cycle of AROs, depreciation "expense" is a Period 2 event. Its precursor in Period 1 is the establishment of the asset that is to be depreciated in Period 2. This asset, called ARC (asset retirement cost) represents "the present value of the expected future spend that will be required to settle the obligation" – that is, the projected CCR spend.

[54] This corresponding asset is the "Asset Retirement Cost," and is part of the long-lived asset (in the Company's case, the coal plants associated with the coal ash basins) whose required closure as a result of changed legal obligations created the liability – the ARO. (Tr. vol. 13, 392.)

obligation the corresponding asset retirement costs are capitalized and are integral to the plant that gave rise to the costs, and this is clear in GAAP and FERC guidance); Tr. vol. 17, 43 (costs are capitalized as part of the property, plant and equipment that gave rise to the retirement obligation); Riley: Tr. vol. 13, 407-08 (FASB does not look at asset retirement cost as being a separate intangible asset; rather it "is part of the coal facility itself … part of that operating long-lived asset"); Tr. vol. 17, 44 (retirement "costs are considered integral to the operation of the asset, in this case the coal plants, and therefore should be capitalized"); id. at 69 (from Riley's national perspective, capitalization of costs is consistent with how they are considered "across the country nationally by utilities").)

Capitalized costs bear a return. The CCR costs incurred by DEP are capitalized costs, funded by the Company's investors, who advanced the funds expecting a return. Operating within its perceived discretion, the Commission held that the deferred funds used to pay for the CCR costs at issue in DEC's prior case

> [W]ere furnished by the Company and its investors, and the costs are eligible for a return on, not merely a return of, those funds, lest its earnings be impaired. In this sense, just like "classic" working capital, these funds are "property" of the Company, used and useful in the provision of electric service to its customers. Such funds, properly accounted for in an ARO, are eligible [for] "deferral and amortization and for earning on the unamortized balance."

(DEC Order, at 292.) The Commission came to the same conclusion in the Company's prior case, although again couching its observation in the context of its perceived discretion: "Costs placed in an ARO account are eligible for deferral and amortization and earning on the unamortized balance. As such, even if the remediation costs are ARO expenditures, they are eligible for ratemaking treatment as though they are used and useful assets." (2018 Order, at 196.) The CCR Costs involved in this case are exactly the same. Nothing has changed, and the *VEPCO* decision and the Public Utilities Act mandate a return. The Commission must award one.

B. Under the Spend/Defer/Recover Model, a Return on the Unamortized Balance of Deferred CCR Costs is Required Lest the Company's Ability to Earn its Authorized Return be Impaired

In the prior DEP/DEC rate cases, the Commission (albeit purportedly in the exercise of its discretion) awarded a return on the unamortized balance of coal ash costs in light of specific circumstances tied to the spend/defer/recover model. The Commission first noted (as we have already seen, see p. 80, above) that coal ash costs had been advanced by investors – that is, the "spend" in spend/defer/recover was investor-supplied capital, and was not already included in customer rates. (2018 DEC Rate Order, at 290-92; see also 2018 DEP Rate Order, at 195.) The Commission noted further that the costs had been deferred by order of the Commission – that is, the "defer" in spend/defer/recover was Commission-sanctioned under the well-defined and long established rules governing deferral, in that CCR Costs were extraordinary in type and magnitude such that failure to defer would have a significant impact on the Company's earned returns. (2018 DEC Rate Order, at 206-07, 292-93; see also 2018 DEP Rate Order, at 138-41.) And, finally, the Commission noted that not awarding a return would impair the "recover" part of spend/defer/recover, because unless the investors who advanced the capital so as to permit the Company to "spend" received a return on the unamortized balance during the Amortization Period, the Company's ability to earn its authorized return would be impaired. (2018 DEC Rate Order, at 290.) That, of course, would mean that the investors would not be fully compensated for the use of their capital.

In the prior DEC case, the Commission concluded "The funds used to pay for these costs were furnished by the Company and its investors and the costs are eligible for a return on, not merely a return of, those funds, lest its earnings be impaired." (Id. at 292.) While the Commission couched this conclusion in the language of "discretion," in reality the same factors it relied upon to award a return in the exercise of its discretion add up to the Company's legal entitlement to a return. That is because impairment of the Company's ability to earn its authorized return is, as the Commission already concluded in the 2018 DEC Rate Order, illegal. The reason for this is the deferral structure embedded in spend/defer/recover and approved by the Commission in the 2018 DEP and DEC Orders.

In DEP's last rate case, the Commission approved the deferral of CCR Costs currently being sought for recovery. (2018 DEP Rate Order, at 138-41.) While that Order is currently on appeal, the deferral was not appealed. No party to the appeal argues in the appeal that deferral of ongoing coal ash costs is improper. Deferral has consequences, as the Commission held:

> The point of a deferral is that the costs to be deferred are of a magnitude that they need to be taken out of the normal ratemaking accounting process and set to one side for later inclusion in rates, lest the Company lose its ability to recover them. Tr. Vol. 9, pp. 123-24. Should the Company's ability to recover such costs be impaired, it will not be able to earn at its authorized rate of return. *Id*. at 124. Setting them to one side means that unless a return is allowed, the Company's ability to earn its authorized rate of return is again impaired. Further, ***if in the process of bringing the deferred costs into rates the costs are amortized over a period of years, not allowing a return on the unamortized costs again impairs the Company's ability to earn at its authorized rate of return. Rates that impair the Company's ability to earn its authorized return are not just and reasonable … and the Commission would act contrary to law were it to order them.***

(2018 DEC Rate Order, at 290 (emphasis supplied).)

In this case the Commission will set an authorized rate of return (ROR) pursuant to N.C. Gen. Stat. § 62-133(b)(4). If it approves the Second Settlement Stipulation between the Company and the Public Staff, that authorized ROR will be 6.93%. As witness Maness indicates, setting the authorized ROR in a rate case means that the Commission is "supposed to give … [the Company] the opportunity to recover just that cost of capital" coming out of the case. (Tr. vol. 7, 36.) But if it in that same rate case the Commission disallows a future cost – the cost of money as CCR Costs are brought into rates in the future, during the Amortization Period – the Commission would automatically and mathematically make it impossible for the Company to earn the ROR it had just authorized.

Company witness Sean Riley, in response to questions by Commissioner Hughes, put the concept in more concrete terms. He noted first that if the Company is actually in an "out-of-pocket cash" situation[55] and it receives less than a full return then "that would be viewed as being a disallowance" (Tr. vol. 13, 404-05) – an implicit disallowance (DEC Tr. vol. 24, 37), but a disallowance nonetheless. Commissioner Hughes posed a hypothetical in which "$500 million was sought … and $500 million was granted, but over a period of time that caused a net present value disallowance." (Tr. vol. 13, 422). Witness Riley's response captures the impairment caused by the loss of the return in terms of the accounting for the loss, but it also illustrates the impairment of earnings implicit in the disallowance:

> [I]n your example, if the Company's seeking $500 million in recovery and they're granted $500 million in recovery, except if the Company is out-of-pocket cash today $500 million and they're not going to recover that for, say, a period of time, call it 25 years, they have used

[55] The Company ***is***, of course, out-of-pocket cash in the spend/defer/recover scenario.

> shareholder monies today, and shareholders expect a return on the use of their funds.
>
> So to the extent that the Commission were to only grant recovery over a 25-year period … in present value dollars it's something less than $500 million.
>
> And what the accounting would require is for the Company to assume or to assess what return would it have expected to get on those dollars, and I would have expected weighted average cost of capital. They would present value of those dollars back to today's dollars to today. Using your example, say that discounts back to $400 million. They would take a charge of $100 million for that implied disallowance in accordance with the accounting standard.
>
> So, in effect, because they're not getting a return on their money, that has to be recognized today as a charge.

(Id. at 422-23.) That same $100 million charge, or implicit disallowance, is – mathematically – an impairment upon the Company's ability to earn its authorized ROR.

Deferred costs are costs pre-paid by the Company and its investors. (Lesser & Giacchino, at 52.) Amortizing them as they come into rates means that investors are lending the money funding the costs to customers. Denying the financing costs attendant upon the loan being repaid over time impairs the Company's ability to earn its authorized ROR – an ROR authorized by the Commission in the very same order that disallows the financing cost.

Impairing the Company's ability to earn its authorized ROR is illegal under *Bluefield*/*Hope*, the requirements of which are built into the rate-making statute through N.C. Gen. Stat. §§ 62-133(b)(1) and 62-133(b)(4). It is also illegal under N.C. Gen. Stat. § 62-133(a), which requires the Commission to set rates that are just and reasonable, and fair to the utility and its customers. A rate order that requires the

Company to make a forced interest-free loan to its customers is not “fair” to DEP and its investors.

Further, sound economic principles underpin the award of a return on the unamortized balance as deferred costs are brought into rates over time. Barring extraordinary circumstances, operating expenses are paid through electricity rates, which are set at a level to cover those operating expenses based upon a test year which, as adjusted, is designed to mimic the electric utility’s ongoing costs. When extraordinary expenditures arise that justify deferral, they are paid not through electricity rates set in anticipation of those costs but by funds advanced by the utility’s debt and equity investors. In order to fully recover these expenditures, the financing cost attendant upon the advancement of the funds needs to be recovered – this is the return “on” those expenditures. Accordingly, the Company is entitled to a return at its weighted average cost of capital to be set in this case upon the unamortized balance of CCR Costs as those costs are brought into rates during the Amortization Period.

These principles were echoed and reinforced in witness Riley’s testimony. He stated that “Once there is a cash outlay by the Company, now there has been a use of investor funds, shareholder funds, it's appropriate to allow a return on the uncollected balances to reimburse shareholders for the use of those funds.” (Tr. vol. 17, 69.) And the flipside is also true – if amounts are collected from customers in advance of the expenditures being made, then customers are reimbursed for the use of their funds through reduction in rate base. (Id. at 69-70.) The Commission recognizes this with respect to excess deferred taxes (EDIT), where “customers prepaid for a cost which will now not materialize.” (Tr. vol. 13, 208.) It has ordered that until EDIT is flowed back to customers or otherwise dealt with, the prepaid amounts bear "interest reflected at the overall weighted cost of capital approved in … [the] Company's last general rate case proceeding." (Id.) EDIT reflects, in effect, a loan from customers to the Company, and the Company will repay the loan, with interest. Likewise, when prudently incurred CCR Costs are brought into rates over time during the Amortization Period, those costs represent a loan from the Company and its investors to customers – and that loan, too, should also bear interest.

The Company's investors, who advanced the funds that are the "spend" in spend/defer/recover, would not have done so had they not had an expectation that their funds so invested would bear a return, and that return is the cost of the money – money they invested that allowed the Company to "spend" and incur legally required CCR Costs. Indeed, the 2018 DEP Rate Order created an investor expectation that a return "on" the unamortized balance of deferred CCR Costs would be awarded in future rate cases – in particular, *this* rate case – so long as the Company met its obligation to prove that the costs for which it sought recovery were prudently incurred. We turn next to this topic.

C. Failing to Award a Return "On" the Unamortized Balance of Investor-Funded Deferred CCR Costs Abrogates Both Investor Expectations of a Return Created by the 2018 DEP Rate Order and the Regulatory Compact

In DEP's prior case, the Commission allowed recovery of prudently incurred coal ash basin closure costs as well as a return on those costs, less a cost of service penalty. DEP had also sought recovery of then-future coal ash costs – which include of course costs *now* sought for recovery – through a "run rate" pursuant to which customers, not the Company's investors, would fund a significant portion of (if not the bulk of) ongoing costs. The Commission rejected the "run rate" concept, and held:

> ***Instead***, CCR remediation costs incurred by DEP during the period rates approved in this case will be in effect shall be booked to an ARO that shall accrue carrying costs at the approved overall cost of capital approved in this case (the net of tax rate of return, net of associated accumulated deferred income taxes). ***The Commission will address the appropriate amortization period in DEP's next general rate case, and, unless future imprudence is established, will permit earning a full return on the unamortized balance.***

(2018 DEP Rate Order, at 206 (emphasis supplied).) Thus, the Commission did not merely *endorse* the spend/defer/recover model in which the Company was engaged, and had been engaged since the laws regarding coal ash management changed with the passage of CAMA and the promulgation of the CCR Rule – the Commission *required* spend/defer/recover. (See Tr. vol. 4, 20 (Commission in not granting run rate forced Company to spend and defer the costs, but indicated that in so doing it would incorporate into rates the financing costs associated with that effort).) Further, the Commission's ruling "puts the focus of the Company's cost recovery request where it belongs – on the Commission's examination of the prudence and reasonableness of the costs for which the Company seeks recovery …." (Tr. vol. 13, 204.) That is, the ruling puts the focus on execution risk, which the Company and its investors properly assume, and not on the risk of an inappropriate disallowance of cost, which the Company and its investors do not and did not assume.

The Company's "next general rate case" is this case. DEP has done what the Commission asked. It booked its ongoing CCR expenditures – deferred by order of the Commission and funded entirely by investors – to an ARO. It has borne the burden of proving that its CCR expenditures were prudently incurred, so "future imprudence" as to the CCR Costs which it seeks to recover has *not* been established. A return during the Deferral Period is not opposed by the Public Staff. All that remains is for the Commission to uphold and fulfill the expectation that it created – the expectation that a return "on" CCR Costs would be awarded during the Amortization Period. Dashing investment backed expectation is a recipe for a "takings" claim. See *Penn Cent. Transp. Co.,* 438 U.S. at 105 . It is also a recipe for the abrogation in North Carolina of the regulatory compact.

The underlying predicate with respect to the costs to be brought into rates over time during the Amortization Period is that the costs were prudently incurred – because if they were not prudently incurred, the Commission would simply disallow them and there would be no question of a return "on" the disallowed costs. Investors accept the risk of prudence-based cost disallowance. That is "execution" risk – the Company must execute in order to recover its costs. But denying a return "on" prudently incurred costs goes well beyond execution risk. Rather, it strikes at the heart of the regulatory compact.

In the 2018 DEC Rate Order the Commission explained in detail the regulatory compact:

> A central operating principle underlying utility rate regulation in North Carolina (and virtually all other jurisdictions) is that the utility's costs are recoverable in rates. As two of the leading modern commentators on utility regulation put it …
>
> > No firm can operate as a charity and withstand the rigors of the marketplace. To survive, any firm must take in sufficient revenues from customers to pay its bills and provide its investors with a reasonable expectation of profit …. Regulated firms are no exception. They face the same constraints ….

> A basic concept underlying all forms of economic regulation is that a regulated firm must have the opportunity to recover its costs. … Without the opportunity to recover all of its costs and earn a reasonable return, no regulated private company can attract the capital necessary to operate.

(DEC Order, at 257 (quoting from Lesser & Giacchino, at 39).) Inducing investment carries a cost, too – the cost of money. Justice Brandeis, in his dissenting opinion in which he articulated the prudence principle, articulated as well that the capital cost, the cost of money, is a "cost" to the utility no less than "operating expenses, depreciation, and taxes." *Missouri ex rel. Sw. Bell Tel. Co. v. Pub. Serv. Comm'n,* 262 U.S. 276, 306 (1923) (Brandeis, J, concurring and dissenting). This Commission has emphatically and repeatedly reaffirmed this principle.[56]

To refuse a return in the circumstances of this case is to disallow financing cost – in effect, as we have seen, to force the Company to provide an interest-free loan to its customers. This has consequences. As DEC witnesses Karl Newlin and Steven Fetter noted, investors vote with their wallets. (Tr. vol. 1, 57 (Newlin); DEC Tr. vol. 26, 135 (Fetter).) They have investment alternatives, and will go elsewhere if their return expectations are not met. Regarding recovery of CCR costs, and all other things being equal, investors "would prefer to go to a jurisdiction that would provide a return of and on as opposed to one … [that] provided just a return of, or even cut back the return of with no return." (DEC Tr. vol. 26, 138.) The evidence in this case shows that other jurisdictions, including Virginia, Georgia, Florida, and Indiana, provide for both recovery "of" and return "on" coal ash costs. (Tr. vol. 3, 56; Tr. vol.

[56] See, e.g., Order on Remand, Docket No. E-7, Sub 989 (Oct. 23, 2013), at 22; Order Granting General Rate Increase, Docket No. E-7, Sub 1026 (Sept. 24, 2013), at 23.

4, 37; Tr. vol. 19, 64-65; DEC Tr. vol. 26, 79-80, 138.) Witness Riley answered "No" to Commissioner McKissick's question regarding whether other jurisdictions were "wrestling with" the coal ash issues (Tr. vol. 13, 410) – "No" because other jurisdictions were allowing "recovery of ***and on***" CCR costs, without disallowance. (Tr. vol. 13, 416 (emphasis supplied).)

The consequence of calling into question North Carolina's continued adherence to the regulatory compact is higher cost of capital, leading inexorably "to increased rates to North Carolina customers." (Tr. vol. 13, 417-18.) As witness Fetter noted, there are "another 180 utilities [investors] could invest in across the country outside North Carolina." (DEC Tr. vol. 26, 148.) That is not an outcome the Company desires, and it surely is not an outcome the Commission desires.

This is not a theoretical issue – the credit rating agencies have already signaled the negative consequences were the Commission to adopt in this case the "no return" treatment it adopted in the Dominion case. Moody's credit reports issued after the 2020 Dominion Rate Order was published contain the same warning – stable ratings outlook[57] is at risk if return on the deferred balance is disallowed. (See Tr. vol. 2, 51-55; Newlin Duke Redirect Ex. 3, at 3; Newlin Duke Redirect Ex. 4, at 4.) The Moody's report for the Company is Redirect Ex. 3 (DEP Report), and was published by Moody's on March 30, 2020. Noting that due to the ratemaking treatment the Company received from the Commission in its last case Moody's viewed coal ash costs as "akin to a capital expenditure" (id. at 4), the report bluntly warns "Our stable outlook assumes Duke Energy Progress will continue to be

[57] "Stable outlook means that the rating agency doesn't intend … to take a ratings action on the Company." (Tr. vol. 2, 49.) A shift to negative outlook would be "a precursor to a downgrade." (Id.)

allowed to recover the majority of its coal ash remediation spending, ***and that it will be able to earn a return on the deferred balance***" (id. at 3 (emphasis supplied)).

The non-theoretical nature of the threat was captured by DEP witness Steve Young, the Chief Financial Officer of Duke Energy Corporation. Noting that the Company's current credit ratings were "solid," he indicated that "where it's headed" was his worry, and central to that worry is the concern expressed by investors, "whether it's equity or debt … [are you] going to get recovery of your cost, including debt service, including the ability to pay a dividend." (Tr. vol. 3, 52.)

Witness Young's testimony establishes that it is the strength of the Company's credit ratings and balance sheet that allows the Company to ride out crises such as COVID-19 (Tr. vol. 3, 55), or shoulder the burdens of hurricane recovery (id. at 53), or successfully navigate the risks of operating nuclear power plants. (Id.) The strength of the balance sheet and DEP's current A-level rating allows it the flexibility to access short-term capital through the commercial paper market, and then go into the longer term debt markets at a time of its choosing, rather than be forced to pay what the market demands at a non-optimal time. (Id. at 54.) This flexibility is what allows the Company to keep capital costs low, but underpinning this flexibility is the "confidence of the lenders that we'll be able to recover all the cost" (id.), which of course includes financing cost. The flexibility goes away if investor confidence goes away – to the ultimate detriment of customers, who must bear the higher cost of capital in rates.

Investors follow and rely upon the Commission's rulings, decisions, and pronouncements. In the Company's prior Order, investors saw that the Commission decided to award DEP a return on the unamortized balance of deferred coal ash costs during the Amortization Period. Without any change in the underlying circumstances, investors will be hard pressed to understand a change in outcome, particularly when the Commission's own words promised no change in outcome.

The cost recovery concern expressed by investors and overhanging the Company's credit and equity profile is not an issue to be addressed by superficial arguments such as "the approval of credit ratings agencies is not a requirement on the Commission in setting rates" (Tr. vol. 3, 41), or that "nowhere in … [N.C. Gen. Stat. § 62-133] does it say that rates have to be set to avoid a downgrade … or increase the stock price of utilities" (DEC Tr. vol. 26, 107), or that Moody's or investors do not dictate the requirements of North Carolina law. These are strawman arguments. No one – least of all the Company – argues that Moody's or investors dictate the requirements of North Carolina law. Cost recovery in North Carolina is governed by the Public Utilities Act, decisions of the North Carolina appellate courts, and decisions of this Commission as it seeks to fulfill its legislative mandate to set just and reasonable rates, rates which must be "fair [both] to the … utility and to the consumer." N.C. Gen. Stat. § 62-133(a).

The proper response to the strawman argument is simple. The law does not prohibit the return; to the contrary a return is required, not because Moody's or investors seek to dictate this result, but because the Constitution and North Carolina law demand this result.

There is no provision of the Public Utilities Act, no decision of the North Carolina appellate courts, and no decision of this Commission that compels the Commission to force investors to bear the financing cost of prudently incurred CCR expenditures as those expenditures are brought into rates over the Amortization

Period. This is particularly true when the costs are being amortized as a rate mitigation measure. There would be no financing cost whatsoever were 100% of prudently incurred CCR Costs included in rates on Day 1. Customers get the benefit of being able to spread the introduction of CCR Costs into rates over time – but the corresponding burden is that they should also shoulder the cost of money that is attendant upon recovery of CCR costs being spread out over time.

The role of the Commission itself in the legal framework of cost recovery cannot be underestimated. The key to the spend/defer/recover framework is the deferral – but for the deferral, we would not be here today arguing about CCR cost recovery, or a return on such recovery, because without the deferral the costs would already have been written off and expensed. (DEC Tr. vol. 23, 59-60.) Deferral, a construct of the Commission itself, is an integral part of the regulatory model that allows for the recovery of ARO costs for a regulated utility. (Tr. vol. 17, 68-70.) It is as much a part of North Carolina's legal landscape as the prudence framework or the concept of "used and useful" costs in rate base.

This brings us full circle to the deferral – which no party challenges – and the consequences thereof. As stated above, in DEC's prior case the Commission held:

> [I]f in the process of bringing the deferred costs into rates the costs are amortized over a period of years, not allowing a return on the unamortized costs again impairs the Company's ability to earn at its authorized rate of return. Rates that impair the Company's ability to earn its authorized return are not just and reasonable … and the Commission would act contrary to law were it to order them.

(2018 DEC Rate Order, at 290.)

Nothing has changed since the Commission wrote those words in 2018. Those words provide the rationale for recovery by DEP of a return "on" prudently incurred CCR Costs as those costs are brought into rates over time during the Amortization Period. Impairing the Company's ability to be "made whole" (Tr. vol. 13, 315) by disallowing its financing cost during the Amortization Period would be unconstitutional under *Bluefield*/*Hope*, and will lead to rates that are unjust, unreasonable, and unfair to the Company, while the Commission's mandate is to set rates that are just, reasonable, and fair to the Company.

Under the circumstances of this case, and in order to be made whole, DEP is entitled to a return at its weighted average cost of capital on the unamortized balance of CCR Costs as those costs are brought into rates during the Amortization Period.

D. The Factors Relied Upon by the Public Staff to Deny the Company a Return "On" the Unamortized Balance are Not Persuasive

The principal reason the Public Staff removes CCR Costs from rate base so as to deny the Company a return on the unamortized balance of those costs during the Amortization Period is to implement its 50/50 "equitable sharing" theory, a theory that as we have seen (see pp. 13-17, above) is standard-less and arbitrary. But protection of its chosen sharing percentage is not the only reason that the Public Staff would deny a return on the unamortized balance. It also makes a legal argument based upon its classification of CCR Costs as "deferred expenses," noting that expenses are not "property used and useful under 62-133(b)." (Tr. vol. 15, 1571.) But that classification of CCR Costs as "deferred expense" was upon a fully litigated record rejected by the Commission in the Company's prior case as "not persuasive, not supported by authority and not determinative … [and] also incorrect as a matter of accounting." (2018 DEC Rate Order, at 289.)

The Public Staff also relies on two additional factors to induce the Commission to exercise what the Public Staff contends is the Commission's discretion to deny a return: (1) intergenerational equity and the matching principle,[58] and (2) an asserted "history" of sharing of extremely large costs, exemplified according to the Public Staff by cases involving the cost of environmental cleanup of manufactured gas plants and the cost of abandoned nuclear generation facilities. Even assuming that the Commission has the discretion to deny a return, neither of these factors is persuasive.

1. Intergenerational Equity and the Matching Principle

The Public Staff asserts that intergenerational equity considerations apply (Tr. vol. 15, 1779), which is a follow on to its argument that CCR Costs are not "used and useful" because they relate to service to customers in the past, with no benefit to present and future customers. But, as we have seen (see pp. 81-82, above), intergenerational equity considerations make no sense in the context of the Company's coal ash basin closure costs, all of which have been incurred since December 31, 2014 as a result of changes in the law and for purpose of complying with legal requirements that did not even exist prior to the passage of CAMA in 2014. The costs recovered in the Company's prior case related to the period from January 1, 2015 through August 31, 2017; the costs in this case relate to the period from September 1, 2017 through February 29, 2020. No customer in "past decades," to use witness Maness' term (Tr. vol. 15, 1779), would ever have had to pay CCR Costs,

[58] It appears based on AGO witness Hart's testimony (see fn. 25, above) as well as the AGO's post-hearing filings in the current DEC case that the AGO argues the same.

because those particular costs did not even exist, and would not have existed, prior to the time the legal requirements for management of coal ash changed in 2014.

Properly understood, intergenerational equity concerns are completely different, and were explained by the Supreme Court in *State ex rel. Utils. Comm'n v. Edmisten*, 291 N.C. 451 (1977). This case involved a gap in the General Assembly's enactment of a fuel adjustment clause. The gap rendered fuel costs incurred by the utilities operating in North Carolina for several months immediately prior to the enactment's effective date uncollectible without relief from the Commission – specifically, a surcharge upon rates to billed in the months following the statute's effective date. The Commission granted permission for the surcharge, but the Supreme Court reversed. Noting that prospective ratemaking, either to recover unexpected past expense or to refund expected past expense that did not materialize, was not authorized by the Public Utilities Act, the Court held

> Such rate making throws the burden of such past expense upon different customers who use the service for different purposes than did the customers for whose service the expense was incurred. For example, the surcharge here in question requires Duke's customers in the winter months to pay more than they otherwise should pay for their service because of the cost of coal burned in July and August in supplying electricity for air conditioning.

Id. at 469-70. Here, by contrast, there is simply no "past expense" to burden present or future customers – CCR Costs in this rate case, which were deferred by express order of the Commission, are currently deferred costs, not yet in rates, being sought for recovery from current and, during the Amortization Period, future customers of the Company. The financing costs will be recovered from customers of the Company contemporaneously with the incurrence of those costs.

2. The Manufactured Gas Plant and Nuclear Abandonment Cases are Inapposite

Citing to cases involving the cost of environmental cleanup of manufactured gas plants and the cost of abandoned nuclear generation facilities, the Public Staff through witness Maness asserts that there is a "history" of sharing "extremely large costs that do not result in any new generation of electricity for customers." (Tr. vol. 15, 1562.) The Public Staff misreads these cases, but even more fundamentally, the Public Staff through this argument imports into the Public Utilities Act a notion ("extremely large costs") that simply does not exist in the Act. Referring in its 2018 Order to testimony from a Company witness who testified in the prior case, the Commission has already held (in yet another "*déjà vu* all over again" moment) that this position is overstated:

> [T]here is "no provision of Chapter 62 requiring different treatment for 'extremely large costs'" (Tr. Vol. 20, p. 141), and, in any event, witness Wright detailed any number of "extremely large cost" items not associated with new generation for which cost recovery is routinely allowed. Id. ***This is yet another example of the arbitrariness inherent in the Public Staff's sharing proposal.*** While the Commission in the past has made decisions to avoid "rate shock" that equitable principle does not apply here in the context of recommended cost disallowances.

(2018 DEP Rate Order, at 189-90 (emphasis supplied).) Moreover, the Public Staff misreads and misapplies both the manufactured gas plant and nuclear abandonment cases, none of which have any relevance to the specific subject at issue – whether the Commission either may or must award the Company a return on the unamortized balance of CCR Costs during the Amortization Period.

a. MGP Case

The manufactured gas plant case (MGP Case) referenced by the Public Staff is the Commission's Order Granting Partial Rate Increase, Docket No. G-5, Sub 327 (October 7, 1994) (MGP Order). This case was addressed by the Commission in its 2018 DEP Rate Order. The Commission, noting that the precedent was of questionable validity in the first place, nevertheless held that it was distinguishable. (2018 DEP Rate Order, at 192-93.) In DEC's prior case, the Commission likewise found the MGP Order neither controlling nor persuasive. (2018 DEC Rate Order, at 277.)

There are indeed many distinguishing features between DEP's current case (and the coal ash cases generally) and the MGP Case. The coal ash cases involve asset retirement obligations arising from a change in legal requirements. AROs did not even exist in 1994, and the environmental cleanup costs at issue in the MGP Case did not arise in connection with asset retirement. As the Commission held in the DEC's prior case, the MGP Case did not "address billions of dollars of CCR remediation costs incurred to comply with EPA and CAMA requirements accounted for in a deferred Commission approved ARO." (2018 DEC Rate Order, at 277.) Moreover, basin closure costs or beneficiation facility construction costs are not "environmental cleanup" costs that were the subject of the MGP Case in any event. (Cf. id. ("The Commission is unable to discern whether the natural gas utility was required to construct lined landfills in which to place contaminated materials or construct caps over any existing repositories.").)

Further, the Commission noted that its ratemaking treatment gave the gas utility an incentive to minimize cleanup costs (MGP Order, at 23) – a factor not present in the coal ash cases, as coal ash costs are driven not by DEC or by DEP but by their environmental regulator, DEQ. Moreover, the Commission noted that its ratemaking treatment would incentivize the gas utility to pursue third-party contributions to cleanup costs. Multiple additional parties, prior owners of the sites in question, were potentially responsible under the applicable state and federal laws and regulations driving the need for environmental cleanup, for at least a share of the costs (id. at 20), and the Commission clearly did not want to dis-incent the gas utility from pursuing those parties by having customers pay the entirety of the costs (id. at 23). Finally, the old MGP sites had not been operated in twenty years as of the time of the MGP Order, and so were clearly not "used and useful" in any sense – by contrast, CCR Costs are "used and useful" (see pp. 80-82, above), and a return consisting of financing costs on unamortized CCR Costs during the Amortization Period is therefore appropriate.

b. Abandoned Nuclear Plant Cases

The abandoned nuclear power generation cases – exemplified by *State ex rel. Utils. Comm'n v. Thornburg (Thornburg),* 325 N.C. 484 (1989) – are similarly inapposite. They were also extensively discussed in the last round of rate cases (see, e.g., 2018 DEC Rate Order, at 276, 280-83; 2018 DEP Rate Order, at 190-92), so we are once again in "*déjà vu* all over again" territory.

In *Thornburg,* the Court concluded that the portion of common facilities at the Shearon Harris Nuclear Plant built to accommodate reactors that were later abandoned were excess facilities. Consequently, these excess facilities could not be included in rate base, because they were not used and useful. The coal ash cases do not involve excessive facilities tied to nuclear units that were never completed and never used to generated electricity. Instead, the coal ash cases involve investor-funded expenditures with a direct relationship to power generation – the utilities' system to address coal ash residue resulting from decades of electricity generation. When new regulations required changes to that system, investor funds were used to modify that system and those modifications were property capitalized as "electric plant utilities." Those investor funds that have been expended (and properly deferred by the Commission) are directly linked to property that was used and useful in rendering services to the public, and, as we have seen, are themselves used and useful in rendering service to the public. (See pp. 80-82, above.)

In the 2018 DEC Rate Order, the Commission noted that as to the nuclear abandonment cases, to the extent relevant at all, their relevance goes to the propriety of "equitable sharing," not the return on any unamortized balance of CCR Costs. (DEC Order, at 276.) The Commission's observation is entirely correct, and it also correctly noted that in *Thornburg* the Supreme Court rejected equitable sharing. (Id. at 281-82.)

The nuclear abandonment cases involve the utility's decision to make an investment that, for reasons unrelated to imprudence or mismanagement, becomes uneconomic. This was described by witness Fetter in his testimony, in the context of a hypothetical jurisdiction wrestling with the fallout of the Three Mile Island incident upon construction of nuclear generation. (DEC Tr. vol. 26, 145-46.) There may be good reason in such a circumstance to not visit the entire economic consequence of the investment decision upon customers, and the "used and useful" requirement – for those jurisdictions that have it – proved to be one means of ensuring that the entire economic consequence of an ultimately uneconomic investment be visited upon customers. (Id.)

CCR Costs are not, however, an investment chosen by DEP or its management in the way that DEP chose to invest in (and then abandon in the wake of Three Mile Island) additional nuclear generation. To the contrary, CCR Costs are costs required by changes in the law – costs that the Company must incur, because failure to comply with the law is not an option for the Company. The nuclear abandonment cases, therefore, do not address the specific return issues with which the Commission grappled in the prior DEC and DEP cases, or that the Commission is once again grappling with in this case. The Commission correctly decided in the 2018 Order that the nuclear abandonment cases were inapposite. Nothing has changed, and it should come to the same conclusion yet again.

E. The 2020 Dominion Rate Case Order Does Not Control the Outcome of this Case

DEP is of course well aware that in the most recent Dominion rate case the Commission granted Dominion only recovery "of," but not a return "on," Dominion's coal ash costs. But that result does not control the outcome in DEP's current case. First, each rate case must be decided in consideration of the record evidence in that case. The record evidence in this case certainly supports a return on the unamortized balance of CCR Costs during the Amortization Period. Second, the Commission must in this case pay heed to the investor expectations embedded in the 2018 Order. There is nothing comparable with respect to the question of a return "on" for Dominion.

1. The Record in this case supports a return, while the Record in the Dominion case may not have supported a return

As the Commission stated in the Dominion Order, its decision was "based on the [Dominion] record as a whole … [and its legal conclusion was that] it is appropriate to treat the [Dominion] CCR costs as deferred operating expenses and not as costs of property used and useful within the meaning and scope of N.C.G.S. § 62-133(b) … ." (2020 Dominion Rate Order, at 134.) The Dominion record supported (at least according to the Commission) the proposition that Dominion's CCR costs were properly classified as operating expense, and the Order itself alludes to the evidentiary basis for that conclusion. (Id. (Dominion witnesses indicated that roughly 98% of the deferred expenditures would have been classified as operating expense in the absence of ARO accounting).)

There is nothing comparable in the evidentiary record in this case. To the contrary, both Company witnesses David Doss and Sean Riley testified that DEP's coal ash costs were all properly and appropriately classified as capital costs (see pp. 83-84, above), and witness Doss responded to this issue directly in his testimony:

Q. [I]s [the] proposition that 98 percent of the closure costs, when you bill it to operation and maintenance, correct in this case, the Duke Energy Progress case?

A. No. Our costs -- and I've got this in my supplemental testimony as well, where I indicated I did a review of the costs from Jessica Bednarcik's supplemental testimony and concluded that those costs were part of the ARO; and as such, as ARO costs, they are capitalized as part of the property plant equipment that gave rise to that capital obligation for retirement.

(Tr. vol. 17, 42-43.) There is no evidence to the contrary save Public Staff witness Maness' testimony that the costs are deferred expense – testimony that this Commission has already determined to be "not persuasive, not supported by authority and not determinative … [and] also incorrect as a matter of accounting." (2018 DEC Rate Order, at 289.)

Further, in the Dominion Order the Commission relied upon a number of historical studies of which it took judicial notice. (2020 Dominion Order, at 127-29, 132.) The fact that the Commission needed to take judicial notice of these studies means that by definition they were not introduced into evidence during the evidentiary portion of the Dominion hearings. The situation in the current DEP case is completely different – the cited studies, along with others, featured prominently in pre-filed testimony from multiple parties, and were heavily discussed and analyzed in the current cases, either directly (in DEC) or through stipulation (in DEP).

For example, among the cited studies are two EPRI manuals, *EPRI Coal Ash Disposal Manual* (2d ed. 1981) and *EPRI Manual for Upgrading Existing Disposal Facilities* (Aug. 1982), which were marked and introduced in the DEC case as, respectively, Joint Ex. 7 and Joint Ex. 8. Both EPRI manuals were the subject of extensive testimony from Company witness Marica Williams, among others. (See Tr. vol. 19, 285-88.) Witness Williams indicates in her testimony that neither manual is particularly instructive with respect to the issues posed in this case.[59] The 1981 Manual, for example, "is written as guidance for designing new disposal facilities, not applicable to existing operating facilities," and she noted specifically that the manual itself stated that EPA at that time had concluded that coal ash was "of relatively low concern." (Id. at 286.) As for the 1982 Manual, which focused on upgrading existing

[59] A later EPRI manual, published in 2004, was also referenced in the Dominion Order (at 128-29), and was discussed in detail earlier in this Brief. It is also, for the reasons indicated above, not instructive with respect to the issues posed in this case. (See pp. 61-62, above.)

disposal facilities,[60] she noted that the document itself announced at its very beginning that the applicable rules were in a state of flux, and that, therefore, "it may be premature for any utility to embark on a program to update their existing disposal facilities." (Id. at 287.)

Another of the historical studies referenced in the Dominion Order is the 1988 EPA Report to Congress (Joint Ex. 13). No matter what the earlier EPRI manuals may have said on the subject of coal ash management, the 1988 Report provided a comprehensive overview of coal ash management practices, and presented EPA's conclusions and recommendations regarding ash management. In short, the 1988 Report was "state of the art" for its time – and state of the art prepared by the very office at EPA led by witness Williams. (See p. 4, above.) If there is a single witness who lived that era at EPA who testified in this case, it is witness Williams. As she noted, in the 1988 Report EPA concluded that no change was necessary to then-current coal ash waste management practices, inasmuch as those practices "appear[ed] . . . adequate for protecting human health and the environment." (Joint Ex. 13, at 7-11.) And, as witness Williams also noted, EPA in crafting its 1988 Report was well aware that then-current waste management practices included, particularly in the Southeastern United States, unlined ash ponds. (See p. 4, above.) The Commission did too, in the 2018 Order. (See p. 5, above.)

The 1988 Report is instructive in other ways. In their references to the historical studies generally (Joint Exhibits 1-13), Intervenors ignored the conclusions reached by any particular study and merely cherry picked an individual sentence or

[60] All of the Company's ash basins had been constructed by 1985.

two from the study that they felt advanced some argument they were making. Witness Quarles provides an object example. His pre-filed testimony cited to the 1988 Report, and stated that a "key conclusion" of that Report was that "The primary concern regarding the disposal of wastes from coal-fired power plants is the potential for waste leachate to cause groundwater contamination." (Tr. vol. 14, 599.)[61] But, as witness Quarles admitted on cross-examination that "key conclusion" is nowhere to be found in the actual conclusions of the Report, which were set forth in Chapter 7 of the Report. (Tr. vol. 14, 682-83.)

Witness Quarles' treatment of the 1982 EPRI Manual (Joint Ex. 8) is similar. In his pre-filed testimony he quotes from the Manual:

> In 1982, EPRI made clear that regulatory compliance by itself might not ensure environmental protection and advised that utilities must achieve both, noting that "[p]otential deficiencies in utility waste disposal practices may be defined by two sets of standards: [1] The disposal practice does not comply with specific federal and/or state regulatory requirements; [2] The site has the potential to contaminate the environment." (1982 EPRI Manual at 4-1.) Accordingly, EPRI reached this conclusion: "[a]n engineering assessment of site adequacy must therefore address (1) whether the operation complies with prevailing regulations, and (2) whether the site poses a threat to the local environment. Both problems must be addressed simultaneously." (1982 EPRI Manual at 4-2.)

(Tr. vol. 14, 601.)

The obvious inference from the quotation that witness Quarles wished to draw is that simply complying with environmental regulation is not necessarily good enough; one must, in addition, do more than merely comply when a site poses the

[61] Witness Quarles presented exactly the same testimony to the Georgia Public Service Commission in Georgia Power's last rate case (see Tr. vol. 14, 717-18; Quarles DEP Cross Examination Ex. No. 2, at 7), and the Georgia Commission rejected it. Georgia is one of the jurisdictions that provide for a both recovery "of" and a return "on" coal ash costs. (Tr. vol. 19, 64; DEC Tr. vol. 26, 80, 138.)

threat of environmental "contamination." But what the authors of the Manual meant by "contamination" is very important to a full understanding of what their recommendations meant – and no one, certainly not witness Quarles, knows what they meant by "contamination." (Id. at 659-60.) This is a key distinction, because whether "contamination" is of the type that could cause environmental harm – that is, harm to the public health and welfare, for example by threatening drinking water – or is merely a regulatory issue is crucial to fashioning an appropriate response, as witness Wells testified. (Tr. vol. 19, 561-62.) Public health risk requires quicker action; a regulatory issue alone requires working with the regulator – in this case, DEQ – to fashion an appropriate solution. DEP did both. (See pp. 62-63, above.)

Moreover, in the 1981-82 period in which the EPRI Manuals were published, the evidence in DEP's case proves beyond a shadow of doubt that DEP, in the face of the types of concerns regarding the potential for environmental contamination from ash ponds, investigated its ponds. (See pp. 48-50, above. The Company had by then already undertaken significant groundwater investigations at its Roxboro and Mayo plants, investigations that showed no significant groundwater impact; indeed, the Floyd Report's conclusion regarding Mayo – a conclusion which witness Quarles ignores completely – was that "it is difficult to imagine that any significant adverse impact on the ground water aquifer could be caused by ponding of the ash wastes at the proposed site." (Floyd Report, at 15.) Monitoring it embarked upon at Sutton in the mid-1980s also showed no significant impact.

Witness Quarles and other Intervenor witnesses may have the luxury of ignoring the actual findings of the studies they bring to the Commission's attention, or cherry picking from massive studies to fixate on a random sentence or two within them. The Commission does not. Should it choose to rely on evidence such as technical reports and scientific literature, it must thoroughly review the reports and literature, not review them in a cursory manner. It must take into account negative evidence from the reports and literature, not simply sweep such "evidence under the rug." *Audubon*, 422 F.3d at194.. If it fails in these tasks, it risks a reviewing court finding it to have acted arbitrarily and capriciously. Id. at 187, 207.

2. Investor expectations regarding a return were not embedded into the Commission's treatment of Dominion's pre-2020 Rate Order decisions, but were embedded into the 2018 DEP Rate Order

The second reason not to import the Dominion case result into this case is the fact that investor expectations were not embedded into the Commission's prior rulings with respect to Dominion's CCR costs. Unlike DEP's current situation, Dominion's prior case (decided in 2016, in Docket No. E-22, Sub 532) was not fully litigated and did not have a significant evidentiary record (2020 Dominion Rate Order, at 123), and so the Commission minimized the prior case's precedential effect. (Id.) The Commission's decision in Dominion's prior case certainly did not have any language even remotely similar to the language in the 2018 DEP Rate Order that creates investor expectation – the language previously quoted (see p. 91, above) and re-quoted here that did not merely endorse spend/defer/recover but required it, and the language that indicates that in future cases, barring a future finding of imprudence, the Commission "will" authorize a return "on" incurred and deferred CCR Costs brought into rates over time in an Amortization Period:

> … CCR remediation costs incurred by DEC during the period rates approved in this case will be in effect shall be booked to an ARO that shall accrue carrying costs at the approved overall cost of capital approved in this case (the net of tax rate of return, net of associated

> accumulated deferred income taxes). ***The Commission will address the appropriate amortization period in DEC's next general rate case, and, unless future imprudence is established, will permit earning a full return on the unamortized balance.***

(2018 DEP Rate Order, at 206 (emphasis supplied).) The Company's next general rate case is this case. The Commission will decide the appropriate amortization period over which CCR Costs are to be brought into rates. But the Commission needs to adhere to its promise that a full return – a WACC return – be earned on that balance.

CONCLUSION

For the reasons set forth herein, the Company respectfully requests that the Commission grant it the relief it seeks herein, that it receive recovery "of" CCR Costs in the amount of approximately $440 million, that those costs be brought into rates over a five-year period beginning with the date new rates go into effect, and that it earn a return "on" the unamortized balance at the authorized weighted average cost of capital approved by the Commission in this case.

Respectfully submitted this 4th day of December, 2020.

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ATTORNEYS FOR DUKE ENERGY PROGRESS, LLC

CERTIFICATE OF SERVICE

DOCKET NO. E-2, SUB 1219
DOCKET NO. E-2, SUB 1193

I hereby certify that a copy of the foregoing **DUKE ENERGY PROGRESS, LLC POST HEARING BRIEF SUPPORTING RECOVERY OF AND RETURN ON COAL ASH COSTS** was served electronically or by depositing a copy in United States Mail, first class postage prepaid, properly addressed to the parties of record.

This the 4th day of December 2020.

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