to bank stability and unnecessarily risked worker safety. In addition, while the Company evaluated interim measures that could offer stability and risk mitigation during excavation, these involved work at and in the river to both access and install the features, and the Company decided not to pursue these measures due to the time needed to obtain a USACE permit for work in the river. He noted that the Company had already initiated the IAB's excavation and that by the anticipated 12-month time period to obtain the permit and 4-6 months to install the required features, the basin would be nearly excavated, and the Company would have to later remove the features to restore the river. Witness Kerin maintained that witness Garrett's proposed two-phased approach would not address these issues, would have unnecessarily put worker and environmental safety at risk, and the delay would have been unacceptable to DEC and to the SCDHEC. Tr. Vol. 24, pp. 112-14, 132.

Witness Kerin disagreed with witness Garrett that the Company should have agreed to different terms in the Consent Agreement with SCDHEC. He explained that, based on SCDHEC's expressed concerns, the deadlines agreed to pursuant to the Consent Agreement were reasonable and allowed the Company to achieve the primary goal of the agreement, which was to excavate ash. SCDHEC's concerns were driven by the IAB abutting the Saluda River and the resulting risk of river impacts, the steepness of the banks, and the heavily wooded nature of the slope. He stated that SCDHEC wanted Duke Energy to take prompt action with respect to excavating the IAB, and that desire is reflected in the Consent Agreement and excavation deadlines. Tr. Vol. 24, p. 115.

Witness Kerin also disagreed with witness Garrett that the Company should have delayed excavation of the Old Ash Fill, noting that the Old Ash Fill was also subject to the Consent Agreement and that the SCDHEC was as adamant that the Company excavate this site immediately as it was with regard to the IAB. Tr. Vol. 24, p. 116.

Finally, witness Kerin testified in response to witness Garrett's criticism of DEC's plan to excavate the Structural Fill Area at W.S. Lee in the future, even though witness Garrett did not suggest any disallowances with respect to this plan. Witness Kerin stated that, in order to resolve the concerns of SCDHEC and environmental groups, the Company agreed to mitigate the future risk of operating two ash management structures by managing all ash at W.S. Lee through a single management structure – the landfill – as opposed to taking a piecemeal approach as suggested by witness Garrett. He stated that if the Company was later required to excavate the Structural Fill area after the landfill project was completed, it would incur greater costs than it will incur by managing the ash while the landfill project is ongoing, and that the decision to excavate this area now is reasonable and prudent approach to mitigating against potential future ash related liability and to reduce future costs for the site. Tr. Vol. 24, pp. 93, 116.

Witness Kerin also testified that Public Staff witness Junis' testimony, similar to witness Lucas in the DEP case, incorrectly asserts that the costs of groundwater treatment wells installed at Belews Creek would not have been incurred absent the Sutton Settlement. Witness Kerin asserted that this conclusion ignores the fact that, while the measures undertaken at Belews Creek were reflected in the Sutton Settlement, they were moved up in time from when they would have otherwise been required, and DEC would have installed extraction wells in order to comply with CAMA even without the Sutton Settlement. Tr. Vol. 24, p. 117.

He also disagreed with witness Junis' contention that the Company should not recover the cost of equipment that could remove selenium at Riverbend. He stated that witness Junis' recommendation does not reflect the reality of managing that facility either at the time of that purchase or at present. He explained that in order to excavate the Riverbend ash, as required by CAMA, DEC had to dewater the impoundments, and that the interstitial water treatment system for the dewatering process was designed to meet NPDES permit limits, including selenium. The environmental consultant hired by the Company to develop this treatment system, WesTech, proposed the SeaHAWK bioreactor system for this purpose. Witness Kerin contended that it was imperative for the Company to have a treatment system that could appropriately treat the site's wastewater and meet future permit selenium limits. He stated that, while the SeaHAWK is important to the Company for staying within its permit limits, it is expensive to operate (approximately $60,000/month), and that the Company will only use it when other physical and chemical extraction methods are insufficient. Witness Kerin emphasized, however, the prudency of having this system in place should it be needed, in order to avoid the need to cease ash removal operations in the case that selenium levels increased and the bioreactor was not on site. He offered the example of a five-month delay to secure a bioreactor would cost the Company several million dollars in delay charges under its contract with Charah. He concluded that it was reasonable and prudent for DEC to purchase a bioreactor system to mitigate against potential violations of NPDES permit limits and to treat decanted wastewater at Riverbend, and that the recommended disallowance of those costs should therefore be rejected. Tr. Vol. 24, pp. 90, 117-19, 132.

Witness Kerin also rebutted AGO witness Wittliff's assertion that the Commission should disallow the Company's coal ash costs, and noted that witness Wittliff's testimony appears to go even further in this case than his recommended disallowance in the DEP case. Witness Kerin testified that witness Wittliff's testimony, with its revisionist history approach to coal ash management and his inability to specify or quantify specific disallowances, is not useful to the Commission. Tr. Vol. 24, pp. 91, 133.

Witness Kerin testified that AGO witness Wittliff's contentions that DEC's management of coal ash has lagged behind the rest of the utility industry, and that the Company has ignored dam safety at its facilities, are incorrect. He asserted that DEC's ash management practices have conformed and evolved with changes in industry practices and regulatory standards. He noted that witness Wittliff based his assertion that the Company knew by 2008 that impoundments were no longer the industry standard in part on excerpts from Duke Energy's 10-K filings around that time. He stated that these excerpts, which pertain to Duke Energy and not to individual utilities like DEC, simply notify the Securities and Exchange Commission of potentially significant coal ash costs that Duke Energy anticipated at that time, and potential new regulatory contingencies to which it could become subject, but were not intended to analyze DEC's coal ash management practices and do not support witness Wittliff's claim that the Company's coal ash management practices were out of step with industry or that the Company knew of any such inconsistency. Witness Kerin also stated that while the 1988 and 1999 EPA Reports cited by witness Wittliff in support of his position show increases in the percentages of new lined landfills and surface impoundments, witness Wittliff acknowledged that the Company last constructed a new ash basin in 1982. In addition, while these reports show an increase in the percentage of basins that were lined from 17 to 28% between 1975 and 1995, 28% is still a minority of new basins being constructed, which is consistent with DEC's practice during this time frame. Witness Kerin stated further that witness Wittliff's assertion fails to account for site-specific conditions, which as the EPA explains in the preamble to the CCR Rule and guidance, is an essential consideration when making CCR unit-specific determinations. Finally, he pointed out that witness Wittliff presented no credible evidence to show that the Company's engineering and design of its impoundments was not consistent with industry practice and regulatory requirements at the time. Tr. Vol. 24, pp. 119-21.

Witness Kerin also rebutted witness Wittliff's assertion that DEC should have built new lined impoundments as opposed to expanding existing unlined impoundments. He testified that witness Wittliff's argument ignores the fact that construction of new lined impoundments would have entailed significant expense to the Company, while not removing the need to maintain existing unlined impoundments. In addition, because such action would have occurred before it was consistent with industry standards, it would have put the Company at risk of disallowance of those costs. Witness Kerin stated that the suggestion that DEC chose not to construct new lined impoundments in order to delay and avoid potential exposure to requirements for more rigorous environmental standards is therefore not only unfounded but also inconsistent with the realities of managing coal ash basins. He noted that, at the hearing in the DEP proceeding, witness Wittliff admitted that the majority of utilities in the country continued to use unlined, wet ash impoundments well after the timeframe in which he alleges the Company should have ceased to do so, because the law allowed them to do it, and the law continued to allow them to do it. Witness Kerin noted the inconsistency between admitting that the Company's use of unlined, wet basins was legal and in line with most utilities in this country, and asserting that DEC was imprudent by doing so. Tr. Vol. 24, pp. 121-22.

Witness Kerin also responded to witness Wittliff's contention that dam safety has not been a priority for the Company, and stated that DEC has a very robust dam safety program, led by a central organization with responsibilities for each site in the system. The program includes weekly documented inspections, and tracking of any corrective actions, as well as episodic inspections to be conducted following heavy rain events or certain seismic events. He stated that the Company also conducts detailed, documented annual inspections of each facility, and that any issues identified are tracked through to resolution. He noted in addition that the Company internally inspects and documents basin discharge piping annually, and again tracks identified issues through to resolution. Any required modifications are managed through a stringent program including plans and specifications submitted to and approved by DEQ's Dam Safety Program. This is all in addition to DEQ's own annual inspections of the basins and all completed modification projects. He stated that the Company provided five-year dam safety inspections dating to the 1970s. He maintained that no instance arose in which the Company failed to act upon a major dam safety issue. He argued that subsequent mentions of certain issues simply show that DEC was monitoring the condition before identifying or confirming the need for longer- term repair, and that these inspections do not show any major issue that threatened the integrity of the dam's ability to retain the ash in the basin. Tr. Vol. 24, pp. 122-24.

Witness Kerin responded to witness Wittliff's criticism of witness Kerin's own CCR experience and qualifications to discuss ash management industry standards, noting the irony of witness Wittliff's position in light of his own limited experience in this area. Tr. Vol. 24, p. 124.

Witness Kerin also testified that, like his testimony in the DEP case, CUCA witness O'Donnell's analysis and recommendation of a 75% disallowance of the Company's coal ash costs relies on multiple analytical flaws that are fatal to his conclusion, and that witness O'Donnell made little effort to address those flaws in his conclusions from the earlier case. Specifically, witness Kerin disagreed with witness O'Donnell's conclusion that his national comparison of CCR assets retirement obligation, or ARO, amounts shows that the Company's ARO is overstated by 75%. He stated that witness O'Donnell appears not to have considered 23 factors that must be accounted for in order to seriously attempt this type of analysis. He also stated that witness O'Donnell made no attempt to quantify DEC's coal ash AROs resulting from CAMA, as compared to its obligations under the CCR Rule, or to determine the impetus for coal ash AROs for the other utilities to which he compares the Company. Witness Kerin argued that witness O'Donnell cannot credibly testify that the Company's ARO coal ash costs are higher because of CAMA when he cannot attribute any specific ARO coal ash costs to CAMA or attribute ARO coal ash costs for other companies to any particular regulatory obligation. He explained that, even if witness O'Donnell had conducted such an analysis, it would not provide an accurate comparison, because other utilities are in very different stages of their coal ash management timeline than DEC. Witness Kerin also maintained that the SNL data relied upon by witness O'Donnell are rough estimates, and that there is substantial uncertainty over the level of actual closure costs for many of those utilities he listed. Witness Kerin therefore recommended that the Commission consider the reasonableness of the Company's ARO amount on its own merits, based on the facts of this case, and without regard to witness O'Donnell's proposal. Tr. Vol. 24, pp. 90, 125-28, 133.

Finally, witness Kerin disagreed with Sierra Club witness Quarles' assertions as to the consistency of DEC's coal ash management practices with industry, the costs of lined landfills as compared to surface impoundments, and Duke Energy's previous pursuits of reuse options for ash. Tr. Vol. 24, p. 91. For the same reasons he presented in response to witness Wittliff's testimony, witness Kerin disagreed with witness Quarles' conclusion that operation of unlined basins after the 1980s was unreasonable, and countered that witness Quarles does not appear to have considered industry standards or regulatory requirements or, like witness Wittliff, to have presented any specific evidence that the Company's impoundment engineering and design was not consistent with industry practice and regulatory requirements at the time. He also testified that witness Quarles' assertion that closure costs for surface impoundments were higher than costs for lined landfills fails to consider the additional costs associated with conversion to lined landfills, in addition to the fact that DEC last constructed a new basin in 1982. Finally, witness Kerin clarified that the Company did make sales of coal ash for reuse during the 1980s, from Marshall in 1986 and Belews Creek in 1988, contrary to witness Quarles' assertion otherwise. Tr. Vol. 24, pp. 128-29, 133-34.

2. Wright

On rebuttal, Company witness Wright testified to several issues related to the recovery of costs associated with coal ash remediation expenses raised in the testimonies of Public Staff witnesses Garrett, Moore, Junis, and Maness, AGO witness Wittliff, and CUCA witness O'Donnell. He stated that, overall, the theories underlying these witnesses' recommended disallowances of these costs are unfounded, do not provide a proper basis on which costs may be disallowed, and should be rejected by the Commission. Tr. Vol. 12, pp. 156-2-3, 161-62.

Witness Wright first disagreed with Public Staff witness Junis' recommendation to disallow approximately 49% of the Company's remaining coal ash costs after accounting for certain other disallowances that he and Public Staff witnesses Garrett and Moore recommend. Witness Wright stated that this recommendation does not align with the appropriate regulatory standard for denial of cost recovery, which he explained is a finding that specifically identified costs are imprudent or unreasonable. He noted that witness Junis did not find the Company imprudent for most of the coal ash-related cost, nor did witness Junis find the Company's costs to be unreasonable. Instead, witness Wright explained, witness Junis asked the Commission to disallow these costs apparently based on the theory that the Company acted poorly in its historical coal ash disposal methods and on speculation of past or future environmental compliance issues. Witness Wright maintained that it is not proper for the Commission to deny cost recovery based on speculation of future findings of violation, or to impose a sharing of costs based upon an undefined culpability standard. Tr. Vol. 12, pp. 156-4, 162-63.

Witness Wright also explained that the proposed sharing of cost is inconsistent with Commission precedent and with the Public Staff's own position on the recovery of coal ash disposal cost in Dominion's 2016 base rate case. In that case, he recalled, Dominion requested a recovery of CCR Rule compliance costs up to and through 2016. He explained that those expenditures included closure and related costs for the Chesapeake Energy Center, even though a court found past violations of the Clean Water Act at this location. He stated that the Commission concluded that the recovery of these costs, as provided in the stipulation entered into in that case by the Public Staff and Dominion, was just and reasonable. He stated his opinion that the CCR cost recovery methodology applied in the Dominion case was correct and should be applied in the same way for DEC. Tr. Vol. 12, pp. 156-12, 163.

Witness Wright also testified that the Public Staff's suggestion that the Commission's treatment of abandoned nuclear plants supports its proposed cost sharing proposal is not appropriate, because abandoned nuclear plant costs are not comparable to CCR costs. He explained that the Commission has found abandoned nuclear cost not to be used and useful, and thus not eligible for rate-based treatment. In contrast, he noted, the coal plants associated with these costs and the related coal ash disposal facilities have been used and useful in providing low-cost, reliable power to North Carolina customers for more than 70 years, and will continue to be used and useful. He stated that this is consistent with the recent Dominion case, where the Commission found that CCR repositories were and continue to be used and useful, were therefore not abandoned, and were therefore eligible for recovery through amortization and a return on the unamortized balance, similar to other types of used and useful property. Tr. Vol. 12, p. 156-16 – 156-19.

Witness Wright proceeded to state that the Commission's treatment of environmental cleanup of manufactured natural gas (MNG) plants also does not support the Public Staff's proposed cost sharing, and referred to his direct testimony that MNG plant costs differ from coal ash disposal costs, both in terms of the time that elapsed between the actual usage of the facility and the environmental-related cost recovery, and in terms of ownership. In addition, he noted that MNG facilities, like abandoned nuclear plants, were found not to be used and useful. He noted further that there is no need to rely on a 23-year-old cost recovery example from a different industry, dealing with assets last used more than 70 years ago, when the best example of the Commission's treatment of coal ash disposal costs can be found in the Dominion case that was decided one year ago. Tr. Vol. 12, p. 156-18.

Witness Wright also testified that the 25-year amortization period proposed by the Public Staff is not justified by their cost sharing theory, which is based on a culpability theory and by defining these costs as being extremely large. He explained that adoption of this proposal would undermine the basic cost of recovery principles embodied in the North Carolina utility regulation and would subject utilities to an unknowable and ill-defined cost recovery standard. He explained further that it could also result in a perception of the State's utilities as riskier, leading to higher cost of capital and cost of service. Tr. Vol. 12, p. 156-22.

Witness Wright disagreed with witnesses who claimed that Duke Energy substantially caused the CCR Rule and CAMA and that, therefore, all costs incurred to comply with these requirements should be disallowed. He referenced his direct testimony that while the timing of CAMA may have been influenced by the Dan River accident, he cannot conclude that the North Carolina legislature would have adopted a different substantive law without Dan River. He noted in addition that there are numerous examples of North Carolina lawmakers and regulators adopting environmental policies, not only specific to this state, but stricter than national or neighboring states' policies. He also noted that state-specific actions to address CCRs have been adopted in a number of jurisdictions. Based on all these factors, he opined that North Carolina likely would have adopted a state-specific CCR regulation regardless of the Dan River accident. Tr. Vol. 12, pp. 156-24 – 156-27, 163-64.

Witness Wright also argued that CAMA was not intended to be a punitive law. He stressed that CAMA does not contain any punitive limitation on cost recovery except for the provision for certain spills to surface water. He also noted that attempts to further restrict coal ash disposal cost recovery under this law have been tried three times, but in all three cases, amendments or laws to disallow cost recovery were defeated. He stated that the General Assembly has shown that it will, when it wants to, adopt specific cost recovery restrictions with other state environmental laws, as exemplified by the Clean Smokestacks Act. In contrast, he explained, the legislature's affirmative decision not to disallow prudently-incurred costs related to CAMA, and not to adopt subsequent proposals to disallow such costs, indicates that CAMA was not meant to be punitive with regard to cost recovery, but rather intended to leave cost recovery determinations to this Commission's oversight and sound regulatory policy. Tr. Vol. 12, pp. 156-28 – 156-31, 164-65.

With regard to coal ash litigation costs, witness Wright reiterated that DEC has excluded from its recovery request all fines, penalties, and fees related to the Dan River accident. Tr. Vol. 12, p. 156. He also opined, however, that witness Junis' apparent position that all of the Company's costs to defend lawsuits should be disallowed recovery, regardless of whether the Company is ultimately found liable or not, is not supported by precedent or sound regulatory policy. First, the Glendale Water case does not support this theory. In addition, he noted that the Commission has recognized that settlements and litigation defense costs, when reasonable and prudent, are recoverable costs, and that the Commission and the Public Staff have also recognized that settlements are beneficial. Tr. Vol. 12, pp. 156-31 – 156-36, 165.

Witness Wright disagreed with the Public Staff's recommendation of provisional cost recovery for coal ash expenditures prudently incurred from January 2015 through August 2017, based on the argument that the appropriateness of such recovery may depend on the outcome of legal determinations. He noted first that this would appear to be retroactive ratemaking. He also stated that the standard is that the utility makes the best possible decisions on expenditures based on the information available at the time, and determinations of the reasonableness and prudency of these costs should not depend on future outcomes of legal proceedings but what was known or knowable at the time. Tr. Vol. 12, pp. 156-39 – 156-40, 165.

Additionally, witness Wright disagreed with Junis' recommendation that costs to remedy environmental violations where the costs exceed what CAMA would have required be disallowed, including those specifically related to Belews Creek groundwater extraction and treatment and a second related Riverbend selenium removal. Witness Wright, citing to his earlier testimony, stated first, that absent a finding that the Company was guilty or had liability associated with environmental issues that led to additional compliance costs, or that the settlement in question Junis was citing to was imprudent, that environmental costs like the Belews Creek costs noted here should be recovered from ratepayers and not shareholders. Secondly, in regard to Junis' statements that DEC had a duty to comply with groundwater rules, and its failure to comply are a reason to deny the recovery of these costs with or without settlement, witness Wright cited his earlier testimony where he discusses how and why unlined coal ash pond exceedances occur and are not unexpected. Moreover, witness Wright noted his earlier testimony in explaining why witness Junis' theory that DEC had a duty to comply with the North Carolina groundwater rules, Title 15A, Subchapter 2L of the North Carolina Administrative Code (2L rules), without regard to whether it followed accepted industry practices, is misplaced. Tr. Vol. 12, pp. 156-36 – 156-38, 162.

Next, witness Wright stated that he disagreed with CUCA witness O'Donnell's belief that the DEC was responsible for the passage of CAMA and should be responsible for any coal ash costs above that required by the CCR Rule, and cited to his earlier statements disagreeing with such. Witness Wright opined that the Commission should reject witness O'Donnell's recommendation that the Company's environmental compliance costs should be disallowed based on a comparison of the alleged national asset retirement obligations, or ARO, amounts relating to CCRs. He stated further that witness O'Donnell's analysis neither considered the fact that most utilities are behind DEC from a timing perspective in both planning and addressing coal ash pond closure, nor reflected the most recent coal ash CCR costs being reported by various electric utilities. Witness Wright also disagreed with witness O'Donnell's statement that the EPA's reconsideration of aspects of its CCR Rule "direct[ly] conflict[s]" with witness Wright's statements about this country's ever-tightening environmental standards. Witness Wright stated that although it was possible that the EPA could modify its current rule, there is no way for DEC to know if, when, or how such modification might occur. Tr. Vol. 12, p. 156-40 – 156-43.

Finally, witness Wright testified that the Commission should reject AGO witness Wittliff's recommendation that because the Company had a "history" of regulatory violations, and due to the Dan River accident leading to the enactment of CAMA, DEC should be disallowed recovery of coal ash related costs. In reference to his earlier statements on CAMA and his direct testimony, witness Wright reiterated his belief that the North Carolina legislature would have adopted some type of state specific coal ash closure legislation shortly after the passage of CCR, regardless of the Dan River accident. He noted that witness Wittliff did not quantify the disallowance he recommends, but instead assumed that the costs incurred to comply with both the Federal CCR rules and CAMA were unreasonable or imprudent without any underlying support. Additionally, witness Wright identified that witness Wittliff's recommended disallowance was also at odds with his testimony filed in the DEP case. Tr. Vol. 12, pp. 156-43 – 156-44, 163-64.

At the hearing, witness Wright explained in response to questions by counsel for the Sierra Club that, if the Commission approved the Company's request for recovery of ongoing expenses, the Company would then bring its actual costs to the Commission for review and approval annually. Tr. Vol. 12, p. 186. Witness Wright also explained in response to questions regarding EPRI documents from the 1980s that those reports acknowledged that more information was being provided about potential impacts from coal ash, but that the reports also advised that disposal procedures not yet be modified. Id. at 191-92. During cross by counsel for NC WARN, he discussed the decision tree that the Commission uses to determine whether costs are recoverable and how that recovery will occur. Witness Wright explained that the first question is whether the costs were reasonable and prudent in providing service to ratepayers and, if so, the next question is whether they were used and useful and, if so, the last stage is to consider what outcome would be fair and equitable. Witness Wright explained further that it is at the last stage where the Commission has leeway to consider different rate designs to achieve a fair and equitable result. Id. at 202-06.

Witness Wright testified in response to questions by counsel for the Public Staff that the fact that DEC has an exceedance or even a violation is not indicative or necessarily tied to the recoverability of costs DEC is seeking in this case. Witness Wright explained that if DEC has a violation and admitted wrongdoing, or an adjudicated proceeding determined there was wrongdoing, those costs or fines should not be recovered. Witness Wright testified that that is different from DEC having to now comply with new standards; in terms of costs associated with new obligations, he considers those long-term compliance costs. Tr. Vol. 13, pp. 77-78, 91-93. On redirect, witness Wright agreed that it is reasonable to assume that state and federal regulators who understood how soil and water interact with each other would have passed appropriate rules and regulations over time to account for that interaction. Tr. Vol. 13, pp. 95-96.

In response to questions by the Chairman, witness Wright confirmed that, in his opinion, the Commission's primary responsibility pertains to cost recovery rather than regulating how utilities implement state and federal environmental laws, and agreed that DEQ was the agency in charge of approving coal ash remediation plans. Witness Wright also agreed that the Commission is not a court of general jurisdiction, and that it determines the reasonableness and prudence of utility decisions rather than make cost recovery decisions by following a duty of care or any other standard available in tort or other type of law. Witness Wright confirmed that this standard does not consider what could or should be anticipated into the future, but considers what is reasonable and prudent given the information known now. Tr. Vol. 13, pp. 99-102.

3. Wells

Company witness Wells testified on rebuttal to the different approach taken by the Public Staff in this case from the DEP case. In the DEP case, the Public Staff attempted to characterize DEP's compliance with its NPDES permits as poor. In this case, witness Junis did not discuss DEC's compliance with NPDES permit requirements, which witness Wells noted has been outstanding, but rather 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.

Witness Wells testified that Public Staff witness Junis' negative characterization of DEC's compliance record is not justified by the historical record. Tr. Vol. 24, p. 224. He explained that exceedances of groundwater standards and the existence of seeps in the vicinity of the Company's ash basins do not indicate mismanagement or poor compliance programs. Witness Wells stated that the existence of groundwater exceedances at or beyond the compliance boundaries at DEC sites is rather a function of where these sites are on the timeline of groundwater assessment and corrective action under modern laws that have changed the way unlined basins are viewed. Witness Wells testified that the Company's decision to use unlined basins to treat ash transport water was reasonable and consistent with the approach consistently employed across the power industry at the time that the basins were built. Witness Wells noted that each DEC site had been properly and legally operating an unlined basin for at least a decade before the adoption of any regulatory requirements related to groundwater corrective action. Witness Wells noted further that as requirements changed over time, DEC has taken every action required by DEQ's groundwater rules, and later by CAMA and the federal CCR Rule, to address groundwater impacts as they have been identified. Tr. Vol. 24, pp. 227-29, 236, 258.

Witness Wells opposed the suggestion that DEC only engaged in comprehensive groundwater monitoring and remediation when forced to do so by CAMA and other developments. He explained that the Company began monitoring groundwater at Allen in 1978, Belews Creek and Marshall in 1989, Dan River and W.S. Lee Steam Stations in 1993, and the remaining sites in or around 2006. He noted that, in 2011, DEQ prescribed a process to be undertaken by DEQ and utilities upon the identification of a groundwater exceedance near a coal ash pond, which included performance of an assessment to determine the cause of the exceedance and, as necessary, develop a Corrective Action Plan consistent with North Carolina groundwater rules. He stated that under that process, only after a utility failed to undertake corrective action when directed to do so would DEQ consider pursuing enforcement. He noted that, contrary to witness Junis' testimony, all of this activity predates the threat of litigation by environmental groups, the DEQ enforcement suit, the Dan River spill, and CAMA. He also testified that, as witness Junis' testimony and exhibits demonstrate, DEC has always promptly responded to any concerns raised by the relevant regulatory entities and where necessary, implemented appropriate corrective action steps to remedy any issue. He stated that the Company has proactively sought consent orders and written agreements to ensure alignment with the regulatory agency as to appropriate scope and timing of additional investigation and corrective action. Tr. Vol. 24, pp. 230-31, 234-36, 259-60.

Witness Wells disagreed with witness Junis' apparent contention that DEC should have moved well ahead of accepted science, regulatory requirements, and industry practice and begun taking measures to prevent any and all groundwater quality issues without regard to the cost of those measures or whether sufficient and proven technology existed at the time to address the conditions at the site. He explained that the papers cited by witnesses Junis, Wittliff, and Quarles discussing potential issues associated with coal ash disposal, and the importance of developing and implementing appropriate controls, highlight the evolving state of knowledge regarding the risks and best practices related to coal ash disposal management, rather than condemn the use of unlined basins. Tr. Vol. 24, pp. 232-34, 258-59.

Witness Wells also testified that North Carolina's groundwater laws were not intended, as witness Junis contends, to be punitive. While he agreed that the groundwater rules require corrective action without regard to fault, he disagreed with witness Junis' conclusion that responsibility for corrective action is equivalent to any other violation of the law. He stated that the record in this case clearly demonstrates that groundwater contamination resulted from DEC's otherwise lawful use of unlined ash basins in furtherance of its mission to provide low cost electricity, and that the use of ash basins was an accepted and reasonable practice conducted with DEQ and EPA oversight. He explained that, for historical sites such as those at issue in this case, this State's groundwater regulations and the DEQ's practices and policies, as well as the CCR Rule, are focused on environmental protection rather than culpability, that the required corrective action is based upon science and not an assessment of wrongdoing. He stated that, in evaluating Corrective Action Plans, DEQ considers numerous factors, including the extent of any threat to human health or safety, impact on the environment, available technology, potential for natural degradation of the contaminants, and cost and benefits of restoration. He concluded that, if the utility cooperates with DEQ, the applicable law and policies are designed to drive corrective action rather than enforcement action, and he saw no intent for those law and policies to be used to deny cost recovery in regulatory proceedings. Tr. Vol. 24, pp. 237-38, 260.

Witness Wells also stated that witness Junis' characterization of groundwater violations under the 2L rules ignores the iterative nature of comprehensive site assessment. He noted that measuring exceedances at different locations in a plume around an activity may result in multiple exceedances of groundwater standards, but that measurement does not result in multiple violations of the 2L rule's prohibition. He explained that this distinction is important for evaluating the claim that the number of exceedances indicates a "breadth of environmental violations." He stated that it would be more accurate to say that, at seven sites, DEC has lawfully operated ash basins that, after decades of use, resulted in exceedances of groundwater standards at those sites. He pointed out how Duke Energy's coal ash basins are some of the most studied sites in North Carolina, with more than 1,400 groundwater monitoring wells, and that the number of exceedances presented by witness Junis signifies therefore the thoroughness of the evaluation rather than a number of groundwater violations. Tr. Vol. 24, pp. 238-40, 260-61.

Witness Wells also explained that the extraction and treatment activity required by the Sutton Settlement, which costs witness Junis recommends for disallowance, is work that the Company simply agreed to perform earlier than required under the CCR Rule and CAMA in order to address offsite groundwater impacts. Tr. Vol. 24, pp. 241, 260.

Witness Wells also disagreed with witness Junis that the amount of litigation regarding the Company's ash basins suggests that the Company was imprudent in managing ash. He opined that the amount of litigation has been driven by nongovernmental organizations that have been pressing for complete excavation of ash from all basins across the Southeast. He stated that DEC has appropriately been opposed to this, arguing instead that final closure methods should be dictated by the CAMA process and a site-specific balancing of net environmental benefits of various closure options based on science, regulatory policy, and the best interest of the Company's customers. He stated that the positions of the NGOs and the suits do not themselves indicate imprudence. Rather, he explained, the appropriate closure methodology must take into consideration the particular characteristics of each site. He stated that the EPA and North Carolina agree and that, consistent with this principle DEC has settled cases where science and engineering supported closure by excavation, and continues to vigorously litigate cases where other closure methods are more or equally protective of the environment at less cost. He concluded that the volume of filed litigation on its own should not factor into the Commission's determination of whether the Company's CCR costs were prudently incurred. Tr. Vol. 24, pp. 242-44.

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. He reiterated that not all exceedances of the 2L standards amount to a violation that requires corrective action under the 2L rules. He also 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. He contrasted this with groundwater standards, under which an exceedance does not immediately result in an NOV and penalty. Instead, he explained the owner/operator must report the exceedance and work with DEQ to determine whether it was due to permitted activity, assess the extent of the exceedance, and undertake corrective action. 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 corrective action is conducted. He testified that the 2L Rules' corrective action provisions are deliberately designed around the idea that older facilities, built before liners were a regulatory obligation, were likely to have associated groundwater impacts, that such impacts were not the result of regulatory noncompliance, and that they should be addressed in a measured process. He concluded that compliance with this process is not mismanagement and should not be held against DEC with respect to cost recovery. Tr. Vol. 24, pp. 244-46.

Witness Wells also addressed seeps. He explained that all earthen impoundments seep, and that DEQ's dam safety regulations acknowledge this. He stated that EPA first directed permitting authorities to address seeps in 2010, and at that time, the Company engaged DEQ to determine the appropriate approach to address seeps and began including them in permit applications. He asserted that DEQ did not consider seeps to have a significant environmental impact. He also maintained that EPA and DEQ did not appear to agree on the appropriate approach to address seeps. He maintained that, absent the CCR Rule or CAMA, the existence of seeps in a basin would not on its own automatically trigger basin closure and should not, therefore, impact the Company's ability to recover its CCR environmental compliance costs. He asserted that, although closing basins would be one way to address seeps, it would be the most drastic of several possible remedies, and both EPA and DEQ have stated that seeps can be addressed by permitting or rerouting, among other options. Tr. Vol. 24, pp. 246-50, 261.

Accordingly, Witness Wells explained, DEC entered into a special order by consent (SOC) with DEQ to address seeps at the Allen, Marshall, and Rogers (formerly Cliffside) stations. He explained that the SOC provides regulatory clarity and certainty as to the appropriate monitoring frequency, parameters to be sampled and limits with respect to the non-engineered seeps, while requiring the Company to accelerate the schedule for decanting water from the basins, a process that is expected to substantially reduce or eliminate seeps. He further testified that DEC is working with DEQ to develop additional SOCs based on this model to address non-engineered seeps at the remainder of DEC's and DEP's impoundments. He clarified that the SOC requirements to accelerate decanting do not create additional costs for the Company over and above the cost to complete these activities in compliance with CAMA and the CCR Rule. In sum, witness Wells testified that the application for and execution of SOCs to address seeps is not evidence of DEC "culpability," but rather a regulatory mechanism to provide clarity and alignment with respect to scope and schedule for compliance-related activities given a change in circumstances, such as a change in requirements or in operations. Tr. Vol. 24, pp. 251-53, 261.

Finally, witness Wells disagreed with witness Junis' suggestion that DEC caused the creation and adoption of the CCR Rule. He testified that the environmental regulatory regime is an ever-evolving body of law, and the EPA engaged in more than two decades of studies before it finally issued a proposed CCR Rule in 2010. Through this process, he noted, the EPA identified 150 cases in over 20 states involving over 25 utilities and government facilities that involved groundwater damage with at least a potential link to coal ash, but determined that immediately closing basins, which would require shutting down operating coal plants, would be more harmful than taking a measured approach. Tr. Vol. 24, pp. 254-55, 261-62.

At the hearing, in responding to questions by counsel for the Sierra Club, witness Wells responded that the Company did engage in voluntary analysis of its coal ash sites prior to DEQ requirements to do so, as far back as the 1970s at Allen, and determined based on those analyses that no significant impacts to groundwater were occurring, and no significant risk to groundwater going forward. Tr. Vol. 25, pp. 36-37.

In response to questions by the Commission, witness Wells confirmed that while the AGO and Public Staff presented documents in this case addressing the Company's actions going back to the 1950s, the AGO took no action itself with regard to coal ash management until 2014, when the AGO became involved with citizen suits. He opined that the reason for that inaction was that the Company's actions with regard to coal ash were acceptable from a regulatory perspective until much more recently. Tr. Vol. 26, pp. 72-73. He also stated that DEC's recent comprehensive studies of the groundwater surrounding the Company's ash basins conducted pursuant to CAMA have confirmed that, while groundwater has been impacted, there is no evidence of any current or likely future impacts to, for example, off-site drinking wells or other receptors at any of the seven sites, and have validated the Company's measured approach to coal ash management in previous years. Id. at 77-80. He confirmed that the Company currently has installed wastewater treatment equipment where needed at all of its basins to comply with CAMA. Id. at 82-83.

In response to questions by the Chairman, he further confirmed that, absent other considerations, there are a number of remedies to address a seep that could be applied rather than to excavate the basin. Tr. Vol. 26, pp. 85-88. He also stated that substances such as iron, manganese, and pH are classified by the EPA as secondary maximum contaminant levels which are regulated based on aesthetics (e.g., taste, odor, etc.) and are not considered health risks. Witness Wells acknowledged that some recent studies have suggested that exposure to extremely high levels of manganese could pose a health risk, but explained that, typically, those levels are orders of magnitude above where the limit was set for aesthetic purposes. Id. at 88-91. Finally, he addressed the difficulty of monitoring groundwater impacts, especially when dealing with naturally occurring elements, and explained that a single monitoring well is a snapshot of that particular area at that point in time, and that conditions 100 yards away could be very different, yet still be naturally occurring. He stated that this is why the Company's efforts to monitor a large area is an iterative process. Id. at 91-93.

4. McManeus

On rebuttal, witness McManeus responded to witness Maness' proposed adjustments regarding coal ash pond closure costs. She explained that there were two main adjustments, to remove ongoing environmental costs and adjust deferred environmental costs, as listed in Boswell Exhibit 1, Schedule 1, and based upon seven specific adjustments proposed by witness Maness. Witness McManeus explained that although the Company disagrees with the majority of the Public Staff's seven proposed adjustments, it does not disagree with witness Maness' third or fourth adjustments. Witness Maness' third adjustment is to add a return on the deferred balance up through the expected date of new rates in this proceeding. The fourth adjustment is to calculate the return using a mid-month convention rather than a beginning-of-month convention. Tr. Vol. 6, pp. 312-14, 357-58.

In regard to witness Maness' second adjustment recommending that the costs DEC has identified as "CAMA only" be allocated based on an allocator that allocates to all jurisdictions, witness McManeus explained that the Company has identified very specific cost categories that should be treated as an exception to the general allocation rule that costs of a system be borne by all of the users of the system. Witness McManeus explained that these costs are unique to North Carolina and that such an exception is consistent with other examples where the Commission has allowed direct assignment to North Carolina, and cited to the cost allocation methods used in regard to the North Carolina Renewable Energy and Energy Efficiency Standard and the Clean Smokestacks Act. Witness McManeus further explained that the Company disagreed with witness

Maness' first, fifth, sixth, and seventh proposed adjustments, and that such adjustments were addressed by other Company witnesses' testimony. Tr. Vol. 6, pp. 312-16, 357-58.

Witness McManeus rebutted the Public Staff's recommendation to exclude the deferred coal ash balance from rate base, and indicated that, to the contrary, it was appropriate for that balance to remain in rate base and for the Company to earn a return on it. She indicated that while witness Doss approached this issue from an accounting perspective, from her viewpoint it was important to recognize that rate base represents the amount of funds supplied by investors. Such funds have been advanced for many purposes, including construction of electric plant, but, she stated, there are other purposes as well – for example, to purchase fuel inventory or to provide cash working capital, etc. Tr. Vol. 6, p. 317. In this particular case, she indicated, investors have advanced funds to pay for coal ash compliance costs, and it is therefore appropriate for the Company to be allowed a return on the deferred coal ash balance during the period for which the Company will amortize and collect these amounts from its customers, as the Company will continue to incur financing costs on the balance of funds that is uncollected. Id. She added that the characteristic that makes the deferred coal ash cost a legitimate component of rate base is the fact that the funds used to pay those costs were supplied by investors. Id. at 318.

Lastly, witness McManeus addressed witness Maness' statement that expenses of operating and maintaining property in rate base in the present or in the future "are allowed to be recovered from the ratepayers on an ongoing basis as operating expenses." Agreeing with his statement, she explained that this is the principle underlying the Company's proposal for recovery of the ongoing annual coal ash basin closure costs, what witness Maness terms the "run rate." Witness McManeus stated that these ongoing compliance costs are no different from other ongoing and recurring expenses the Company incurs in the test year, and that such costs are equivalent to the Company's reasonable and prudent test year coal ash basin closure spend. She further explained how the Company's proposed recovery of these ongoing compliance costs through rates would be subject to true-up in subsequent rate cases so that only actual costs are recovered. In conclusion, witness McManeus cited to Chairman Finley's statements in the recent DEP rate case proceeding that a rider could be an alternative mechanism for cost recovery of on-going compliance costs, and stated that the Company agrees that a rider would be an appropriate alternative mechanism to recover such costs. Tr. Vol. 6, pp. 315-16, 357-58.

5. Doss

Witness Doss rebutted the Public Staff's positions regarding ARO accounting that the Company employed for its deferred coal ash compliance costs, and, in particular, witness Maness' characterization of those costs as a deferred expense. Witness Doss provided a detailed explanation of the GAAP and FERC accounting rules with respect to the ARO established in connection with the Company's coal ash basin closure obligations, as well as the deferral orders issued by the Commission in Docket No. E-7, Sub 723. Tr. Vol 12, pp. 61-71. He noted that the Company had simply accounted for these costs as required under GAAP and FERC Uniform System of Accounts, and had deferred the impacts of ARO accounting, as authorized by the Commission's deferral orders. Id. at 70-71.

Witness Doss also responded to witness Maness' opinion that coal ash costs should not be classified as "used and useful" costs. He indicated that, to the contrary, under GAAP and FERC accounting guidance, the asset created when a Company initially recognizes an ARO is considered part of the property, plant and equipment for the assets which must be eventually retired. Id. at 71. He noted further that such costs are used and useful in that they 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, and that the achievement of those three purposes is used and useful as the utility has the obligation to comply with CAMA and the CCR Rule. Id. at 73.

Commission Determinations

General Cost Recovery Principles

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 in the opening paragraphs to a chapter (titled "The Role of the Revenue Requirement") in their treatise on utility regulation:

> 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.

Jonathan A. Lesser & Leonardo R. Giacchino, Fundamentals of Utility Regulation 39 (Pub. Utils. Reports, Inc., ed., 2007) (Lesser & Giacchino).

Lesser & Giacchino refers to the concept of cost recovery as the "revenue requirement" (id.), and the North Carolina Supreme Court has also acknowledged its central role in utility ratemaking. See, e.g., State ex rel. Utils. Comm'n v. Thornburg, 325 N.C. 484, 490, 385 S.E.2d 463, 466 (1989) (Thornburg II) and State ex rel. Utils. Comm'n v. Thornburg, 325 N.C. 463, 467 n.2, 385 S.E.2d 451, 453 n.2 (1989) (Thornburg I), in which the concept is stated to be embedded in the statutory rate making formula, and, indeed, expressed formulaically:

> This statute [N.C. Gen. Stat. § 62-133] requires the Commission to determine the utility's rate base (RB), its reasonable operating expenses (OE), and a fair rate of return on the company's capital investment (RR). These three components are then combined according to a formula which can be expressed as follows:
>
> (RB x RR) + OE = REVENUE REQUIREMENT

Costs are not recoverable simply because they are incurred by the utility. The utility must show that the costs it seeks to recover are (1) "known and measurable"; (2) "reasonable and prudent"; and (3) where included in rate base "used and useful" in the provision of service to customers. Lesser & Giacchino, at 41-43. But once it has shown that these metrics are met, the utility should have the opportunity to recover the costs so incurred. This is what North Carolina's ratemaking statute requires (see N.C. Gen. Stat. § 62-133(b)(5)), and to do otherwise would amount to an unconstitutional taking.

In this case, no party has questioned whether the coal ash basin closure costs for which the Company seeks recovery are "known and measurable"; indeed, the Company documented these costs and has shown that they were in fact incurred. Rather, the arguments raised by Intervenors challenging the inclusion of the Company's coal ash basin closure costs in rates center on whether those costs are "reasonable and prudent" and whether they are "used and useful." These concepts have been framed by this Commission and the North Carolina Supreme Court.

A. Reasonable and Prudent

The seminal treatment of "reasonable and prudent" costs is this Commission's order entered in Docket No. E-2, Sub 537 (the 1988 DEP Rate Case), in which the Commission approved with some exceptions costs the Company incurred in connection with the construction of Unit 1 of the Shearon Harris nuclear plant. See 1988 DEP Rate Order. The Commission there articulated the following principles governing the question of "reasonable and prudent":

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 under question. Perfection is not required. Hindsight analysis – the judging of events based on subsequent developments – is not permitted." 1988 DEP Rate Order, p. 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; and (3) quantify the effects by calculating imprudently incurred costs. Specifically,

- A decision cannot be imprudent if it represents the only feasible way to accomplish a necessary goal.
- The Commission can only disallow imprudent expenditures – that is, actions (even if imprudent) with no economic impact upon customers are of no consequence. Thus, identification of an imprudent action or inaction is not by itself sufficient; rather, there must be a demonstration of the economic impact.
- The proper amount chargeable to customers is what the expenditure would have been absent the imprudent acts or decisions of management.

Id. at 15. The North Carolina Supreme Court upheld the Commission's prudence determination. See Thornburg II, 325 N.C. at 489, 385 S.E.2d at 466 (finding "no error" in that portion of the Commission's decision).

B. Used and Useful

"Used and useful" is a concept directly embedded in the ratemaking statute – N.C. Gen. Stat. § 62-133(b)(1) states that the Commission must "Ascertain the reasonable original cost of the public utility's 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, less that portion of the cost which has been consumed by previous use recovered by depreciation expense …." In general, the Supreme Court's treatment of the concept has been in the negative, i.e., asserting as a basis for its decision that something is not "used and useful" – for example, excess common facilities are not "used and useful" as a matter of law, see Thornburg II, 325 N.C. at 495-96, 385 S.E.2d at 469, and a water treatment plant that was not in service as of the end of the test year and would never again be in service was not "used and useful" within the meaning of N.C. Gen. Stat. § 62-133(b)(1). State ex rel. Utils. Comm'n v. Carolina Water Serv., Inc., 335 N.C. 493, 508, 439 S.E.2d 127, 135 (1994). The reverse, of course, is that if the expenditures do support and provide service to customers, the costs are "used and useful."

C. Burden of Proof

The Commission must address arguments on the burden of proof. DEC argues that it incurred the CCR remediation costs at issue, meeting its prima facie burden and that Intervenors have failed to justify discrete disallowances. The AGO argues DEC bore the burden of quantifying the disallowances the AGO deems appropriate. DEC argues that the substantive standard is imprudence. Others argue that the standard is one of due care. The CCR remediation costs DEC seeks to recover in this docket and that are being challenged by Intervenors consist of 2015-2017 costs to dewater, remove, and transport CCRs from unlined repositories and store them in lined ones or to install caps. DEC incurs these costs pursuant to requirements of EPA CCR Rule and North Carolina CAMA provisions or other requirements of DEQ. In compliance with this Commission's authorization, these costs have been accounted for in an Asset Retirement Obligation account and have been deferred to permit appropriate ratemaking treatment in this case.

The AGO argues that DEC should bear the burden to disprove why disallowances to its 2015-2017 CCR remediation costs should not be accepted.

> The AGO does not agree that the factors the Commission found appropriate for an approach taken by an independent auditor in the 1988 DEP Order should have been applied in the 2018 DEP Rate Order as a prudence framework, and similarly in this general rate case, the prudence framework is inappropriate because it essentially puts the burden of proof on intervenors, contrary to settled law. As the Commission observed in the 2018 DEP Order, because costs are site-specific, establishing a past cost would be a "near impossibility." 2018 DEP Order p. 200. As discussed in detail in Part I.B below, there is extensive affirmative evidence that Duke's imprudent management of coal ash disposal and coal ash sites, and its delays in addressing known problems, have driven up the costs now being incurred and have shifted the costs onto future customers unfairly. It is not appropriate to require ratepayers to prove that costs are unrecoverable; rather it is up to Duke to prove that some or all of the detailed costs are not attributable to the poor history of operations; that prudent alternatives that would have reduced the costs were not available when problems became known; and that these factors support the reasonableness of the costs Duke seeks to recover.

AGO's Brief, pp. 9-10.

The AGO cites no authority for this argument, nor does it argue that cases and precedent relied upon by DEC and the Commission in the 2018 DEP case to the contrary are wrongly decided or should be ignored. While asserting that the Commission's reliance on established evidentiary principles in the 2018 DEP case is "contrary to law," the AGO cites no authority to back up its assertion. The AGO asserts in response to DEC's petition to recover 2015-2017 CCR remediation costs -- costs no party asserts DEC did not incur -- that these costs should be disallowed due to DEC's imprudence in years prior to 2015. These are the AGO's allegations, not DEC's. The AGO's novel theory that a petitioner should bear the burden to disprove Intervenor allegations unsupported by evidence is one the Commission does not accept. The AGO's theory of its case, at least in its brief, appears to be that if DEC had acted to remediate CCR disposal and storage issues in years prior to 2015, DEC's costs would have been lower, so the 2015-2017 costs are excessive. To prevail, the AGO must quantify what the costs of the actions not taken should have been. The AGO argues DEC failed to act appropriately before 2015. DEC cannot be expected to provide costs of acts not taken. The AGO has not undertaken this task.

While some of the costs to comply with the requirements of environmental regulators are challenged by Intervenors as excessive, i.e., unreasonable, most of the costs being challenged are questioned on the theory that DEC is in breach of a standard classified as a "duty to exercise due care." The challenge equates failure to meet a due care standard with management imprudence. According to this theory, even though no environmental regulatory requirement imposed a duty to remove CCRs from unlined impoundments before EPA CCR rules or CAMA, management was imprudent in not doing so. The challenge does not address DEC's decisions to initially place the CCRs in unlined impoundments between 1945 and 1982, but its failure to remove the CCRs thereafter or alternatively to cease to sluice CCRs to these unlined impoundments at a time when trends within the industry suggested that leachate finding its way into groundwater from the bottom of the unlined repositories posed potential risks to the environment and human health.

The Commission has not been cited any case 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's decisions should be assessed against a standard of due care. The Commission's duty 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 a breach of a duty of due care, if any, such as that advocated by certain Intervenors in this case. The issue before this economic regulatory tribunal is imprudence - who should bear the remediation costs - the utility's stockholders or its consumers and on the basis of what justification.

According to the U.S. Supreme Court:

> Good faith is to be presumed on the part of managers of a business. ... In the absence of showing of inefficiency or improvidence, a court will not substitute its judgment for theirs as to the measure of a prudent outlay.

West Ohio Gas Co. v. Ohio Pub. Utils. Comm'n., 294 U.S. 63, 72, 55 S. Ct. 316, 321 (1935).

In a case cited with favor in Priest, Principles of Public Utility Regulation:[57]

> Only where affirmative evidence is offered challenging the reasonableness of the operating expenses incurred, on the grounds that they are exorbitant, unnecessary, wasteful, extravagant, or incurred in the abuse of discretion or in bad faith, or are of a nonrecurring character not likely to recur in the

[57] A.J.G. Priest, Principles of Public Utility Regulation 1969, Vol. I, pp. 422-23.

future, has the commission a reasonable discretion to disallow any part of the expenses actually incurred.

Alabama Pub. Serv. Comm'n v. Southern Bell Tel. & Tel. Co., 253 Ala. 1, 42 So.2d 655, 674 (1949) cited with approval, State ex rel. Utils. Comm'n. v. Intervenor Residents, 305 N.C. 62, 77, 286 S.E.2d 770, 779 (1982).

This standard against which costs recovery challenges are measured has elements qualitatively and quantitatively distinct and more rigorous than a tort standard of due care. The expert witnesses sponsored in this case failed to support allegations of discrete actions constituting imprudence. For its equitable sharing disallowance, the Public Staff proceeded on an equitable sharing theory, not on a theory of imprudence. AGO witness Wittliff on cross-examination failed to show what DEC should have done differently to remediate CCR, when it should have acted, and what the cost of such alternative conduct should have been. While AGO witness Wittliff filed forceful allegations on paper in the prehearing filings, much as was the case in the DEP rate hearing, his support of that testimony from the stand on cross examination was not persuasive.[58] Public Staff witness Junis likewise could not identify costs DEC would have incurred to remediate prior to 2015.[59] Without record evidence from parties advocating disallowances

[58] Q. Beginning on line 16, you state, "However, when it came to making changes to its own unlined surface impoundments, the Company chose not to move forward with the industry, but instead chose to add more and more coal ash to the unlined impoundments despite the longstanding seepage and groundwater issues at its facilities."

Did I read that correctly?

A. You did.

Q. Mr. Wittliff, despite your 30 years of experience as an engineer, I am correct, am I not, that if I look through the entirety of your testimony in this case and all of your exhibits, I will not find any engineering analysis of what exactly that DEC should have done, when it should have done it, where it should have done it, and how much it would have cost with respect to the lines in the testimony that I just read you, will I?

A. Say that again, please.

Q. Yes, sir. You make a contention, on page 10 of your testimony, on line 17 through 20 that I just read, alleging that DEC chose not to move forward with the industry, but instead chose to move more and more coal ash to unlined impoundments.

My question is, if I want to look at how I should have moved forward with the industry, where I should have done it, when I should have done it, how much it should have cost me - and by "me," I'm referring to DEC - I cannot find those answers anywhere in your prefiled testimony, can I?

A. No.

Tr. Vol. 11, pp. 283-84

[59] "The coal ash-related environmental violations have a cost. Corrective actions to address environmental impacts under CAMA and the Environmental Protection Agency's (EPA) Coal Combustion Residuals Final Rule (CCR Rule), including ultimately closure of all DEC ash basins, will remedy the environmental violations. Therefore, it is not feasible to identify all the costs that would have been incurred to remedy violations under the pre-existing environmental regulations and laws, such as 15A NCAC 02L (2L rules) and North Carolina General Statute 143-215.1, if CAMA and the CCR Rule were not in effect. . . . There is no doubt that substantial assessment and remedial costs would have been incurred without CAMA and the CCR Rule, but, in my opinion, those costs cannot be quantified without undue speculation."

Tr. Vol. 26, pp. 646-47

for failure to take CCR remediation steps prior to 2015 pursuant to the burden of proof theory or an unsupported "failure to exercise due care standard" of what action DEC should have taken, when it should have acted, and what the costs would have been, the Commission cannot approve such specific disallowances. Attempts to identify years-old hypothetical past costs, for example, by allocating tons of CCRs to formulate inexact allocation percentages to be applied to 2015-2017 costs is to rely upon guesswork that simply is legally and equitably deficient.[60]

Coal ash located within basins above levels saturated by water and unaffected by the contours of the bottom of the impoundment can be removed at a cost lower than coal at lower levels. Costs of replacement repositories will vary depending on land costs, location, regulatory requirements and site preparation costs. Transportation costs will vary depending on distance, market conditions, regulatory requirements and timing of incurrence.

Efforts to identify what DEC should have done prior to EPA CCR and CAMA, when it should have done so and what the costs should have been even with the benefit of 20/20 hindsight pose insurmountable obstacles. CCR remediation even under the supervision of NC DEQ is a site-specific undertaking with procedures that have evolved over time and continue to do so. Without statutory or regulatory standards and guidelines to follow, no one can say what the prudent course would have been even if one acts on the assumption that DEC was imprudent to await promulgation of the definitive environmental regulatory requirements.

Under EPA CCR regulations and CAMA requirements, the prevalent remediation remedy is dewatering, excavation and removal or cap-in-place. These explicit, express requirements depend heavily on NC DEQ oversight and supervision. The remediation steps must be completed in compliance with deadlines and substantial collaboration between NC DEQ and DEC with respect to permitting. Compliance will occur as far into the future as 2028. No one can predict today how compliance will be accomplished or what these future compliance costs will be. The decision by NC DEQ on whether cap-in-place for eligible impoundments versus CCR removal has yet to be made. Yet Intervenors ask the Commission to look backward where the regulatory requirements were not in place and therefore unknown and speculate what it would have cost to comply so as to impose the imprudence disallowance. Having failed to even attempt to quantify such a disallowance, Intervenors' theory is without probative support and must be rejected.

Without any requirement such as EPA CCR rules or CAMA to remediate CCRs stored in unlined pits simply because unlined pits posed "potential" threats to the environment, Intervenors must "pick a date" when in their opinion such remediation should have been undertaken. Likewise, Intervenors apparently assume the remediation

[60] When quantifying quantities of CCR for purposes of cap-in-place, utilities rely upon linear measurements, not tonnage.

remedy would have been dewatering, excavation and removal or perhaps cap-in-place, even though they do not agree on which of these alternatives is appropriate for each basin. No support for this assumption exists. Without requirements such as those of EPA CCRs and CAMA, DEC logically would have attempted to investigate each unlined repository to determine insofar as possible the extent to which contamination was occurring or had the potential to occur. Absent evidence of actual or probable future contamination, DEC would have been remiss in spending millions of dollars to remediate or to choose the most expensive remediation alternative.

As to impoundments where contamination was occurring or potentially would occur, remedies far short of complete excavation such as installing water extraction methods beyond the impoundment to remove water or to excavate contaminated soil were available and arguably should have been employed as a least cost solution.

Any CCR impoundment leaks, whether lined or unlined. The underlying soil composition and subsurface groundwater flow direction for each site are significant considerations in assessing risk of harmful contamination from CCR constituents. Piedmont red clay acts as a natural sealant. Unless CCR contaminants in excess of proscribed levels migrate beyond boundaries outside repositories, no actionable threat occurs. Monitoring wells provide tools to measure migration of harmful constituents. Determinations of naturally occurring levels of CCR contaminants must be made to determine whether measurements in excess of published standards, if any, originate at the impoundment.

Determining the number and placement of monitoring wells, not an inexpensive endeavor (Tr. Vol. 26, p. 92), is an inexact science. The prevalent and cost-effective process is to install monitoring wells iteratively to best identify harmful groundwater contamination. Tr. Vol. 26, pp. 92-93. Evidence of excessive constituent levels up gradient of impoundments tells nothing about impoundment contamination but is necessary to identify naturally occurring constituents that may or may not exist down gradient. Unlike synthetic contaminants like dry cleaning fluid or nuclear waste where evidence of its presence in groundwater can be tied to a source of pollution, all the potentially harmful elements from coal ash occur naturally in the ambient environment. Tr. Vol. 26, pp. 92-93. Underground water flows may dissipate excessive levels of CCR contaminants through natural attenuation to those below standard thresholds. There may be no receptors in the vicinity of the impoundment.

The best evidence of the difficulty in determining what DEC should have done, when it should have done so and what the cost should have been prior to 2015 is the significant dispute that arises in this case over what DEC should have done, when it should have done so and what the costs should be with respect to the actual 2015-2017 costs. DEC actually has incurred these costs in its efforts to comply with EPA CCR and CAMA published standards and requirements undertaken under NC DEQ's supervision and guidance. Parties to this case hotly dispute where replacement repositories should be constructed, when and how CCRs should have been transported, and which CCRs should have been designated for beneficial reuse.

Consequently, the Commission determines that efforts to recreate the past as no party has been able to do so is a fruitless endeavor that the Commission is unable and unwilling to undertake.

Additional complications to certain Intervenors' theory that disallowances to 2015-2017 CCR remediation costs should be made because DEC failed to begin remediation or alternative CCR storage earlier magnify the fatal flaw in the theory. From an accounting cost recovery perspective, the Commission authorizes establishment of an ARO, defers costs for remediation, and later amortizes these deferred costs over five years. DEC began to incur the remediation costs in 2015 and will continue to do so under EPA CCR and CAMA regimes until 2028. Consequently, under procedures being followed, cost recovery will occur through 2033. If, under certain Intervenors' theory, DEC should have begun remediation in 2006 (hypothetically, because Intervenors cannot identify the starting date under their theory), DEC would still have been incurring CCR remediation costs during the test year and would have been amortizing CCR remediation costs from prior years. Consequently, ratepayers paying rates established in this case could very well face the possibility of being no better off under Intervenors' alternative, unsubstantiated theory. Perhaps, arguably, DEC should have established a coal ash remediation cost ARO earlier in anticipation of a future requirement to undertake remediation efforts, and costs not so accounted for should be disallowed. However, the Commission's practice is not only to approve the establishment of the ARO but to defer the costs accounted for in the ARO for later recovery in a general rate case. Theories relied upon to recreate the past based on hypothetical scenarios all depend on guesswork and subjective factual constructs that are beyond the ratemaking standards this Commission must employ.

The burden of proof to show that rates are just and reasonable is always on the utility. See N.C. Gen. Stat. § 62-134(c). Intervenors, however, have a burden of production in the event that they dispute an aspect of the utility's prima facie case. See, e.g., State ex rel. Utils. Comm'n v. Conservation Council, 312 N.C. 59, 64, 320 S.E.2d 679, 683 (1984) (utility's costs are "presumed to be reasonable" unless challenged); State ex rel. Utils. Comm'n v. Intervenor Residents of Bent Creek/Mt. Carmel Subdivisions, 305 N.C. 62, 76-77, 286 S.E.2d 770, 779 (1982) ("The burden of going forward with evidence of reasonableness and justness arises only when the Commission requires it or affirmative evidence is offered by a party to the proceeding that challenges the reasonableness of expenses…."). If the Intervenor meets its burden of production, the ultimate burden of persuasion reverts to the utility, in accordance with N.C. Gen. Stat. § 62-134(c).

The Commission has consistently followed this shifting burden framework. See, e.g., DEC Remand Order, (Docket No. E-2, Sub 1142) p. 34. In practice this means that Intervenors may not rest merely on arguments and theories, they must adduce actual evidence challenging some aspect of the Company's cost recovery case. Further, that evidence must support the Intervenor's challenge under the substantive standard established by North Carolina law. Evidence predicated on 20/20 hindsight is insufficient to effectuate a prudence challenge, inasmuch as the substantive prudence standard forbids hindsight analysis.

D. Conclusion with respect to January 1, 2015 - December 31, 2017 Costs

The Commission determines that the Company has met its burden – both the prima facie burden of production and the ultimate burden of persuasion – of showing that the coal ash basin closure costs it actually incurred from January 1, 2015 through December 31, 2017 are recoverable and that a return, but one reduced to recognize a mismanagement penalty, is warranted, and that the Commission with contrasting evidence on the merits, with exception addressed below, authorizes recovery.

First, Company witness Kerin demonstrated that the Company's coal ash management historical practices (i.e., pre-CCR Rule and pre-CAMA) have generally comported with industry practices and then-applicable regulations, especially in this region of the country. See, e.g., Tr. Vol. 14, pp. 99-100, 135. The Commission determines that compliance with industry standards is an important but not the sole criterion in determining the recoverability of CCR remediation costs. As part of his work to bring DEC into compliance with the new CCR Rule and CAMA, witness Kerin helped establish and participated in an industry peer group consisting of representatives of, for example, Dominion and Southern Company, and his interaction with that group and his investigation of practices at other Duke Energy Corporation-affiliated utilities confirm his conclusion that the Company's practice was not out of line with the overall industry practice. Id. at 96-97. As witness Kerin testified, when he looked at all of the practices at the Duke Energy Corporation utilities, in multiple states, "Indiana, Ohio, North Carolina, South Carolina, and Florida, all those practices were the same, so that led me to believe that all those [companies], prior to becoming Duke Energy companies, were managing their ash and their ash basins in the same manner." Id. at 158-59. He made the same observation concerning the peer group of companies – AEP, Dominion, the Southern Companies and TVA – and "their practices were similar." Id. at 159. He concluded: "So that whole group of states across the eastern part of the United States, we were operating our basins in the same fashion." Id.

Witness Kerin's testimony on this point was not seriously or credibly controverted by any Intervenor. Indeed, AGO witness Wittliff was not able to specify exactly how the Company should have acted differently in managing its coal ash to be consistent with industry, at which sites it should have taken those actions, and how much those actions would have cost the Company. Tr. Vol. 11, pp. 283-89. Witness Wittliff also presented no credible evidence showing DEC's engineering and design of its impoundments was not consistent with industry practice and regulatory requirements at the time other than his own, subjective allegations. Tr. Vol. 24, p. 121.

Moreover, key documents that Intervenors used in cross-examination in an effort to rebut witness Kerin's testimony contain provisions that in part support, to some extent at least, his testimony and these findings. For example:

- Los Alamos Laboratory Report (1979): "Much of the ash produced by coal ash combustion is discharged into ash ponds." Sierra Club – Kerin Cross Ex. 3, p. 6.
- EPRI Coal Ash Disposal Manual (1981): No coal ash was landfilled in either North or South Carolina; rather, all of it was stored in ponds. Sierra Club – Kerin Cross Ex. 4, Table 3-1, pp. 3-7. Further, 81% of the coal ash produced in the Southeast was placed in ponds. Id. at 3-8.
- EPA Report to Congress (1988): This Report (Sierra Club – Kerin Cross Ex. 5) confirms that the Company's disposal of coal ash in ponds conformed in large measure to industry practice. The Report refers to ponds as "surface impoundments" Id. at 4-11, and notes that CCR waste management practices varied by region, and that in the South (EPA Region 4, which includes North and South Carolina) 95% of the plants manage their CCRs on-site. Id. at 4-23. The Report continues, "On-site management is common because utilities in this region often use surface impoundments, which are typically located at the power plant." Id. It noted further that "access to abundant, inexpensive supplies of water ... [in Region 4] often made it economical to use this management option." Id. at 4-20.

The 1988 EPA Report also indicates that "until recently, most surface impoundments and landfills used for utility waste management have been simple unlined systems," and that "liner use has been increasing in recent years." Id. at 4-33. Intervenors point to these statements to argue that the Company's continued use of unlined ponds was outside standard industry practice and is otherwise imprudent. The Commission disagrees. The Report notes, for example, that 87% of surface impoundments were unlined (id. at 4-33), and that neither North Carolina nor South Carolina required liners. Id. at 4-3. It also notes that one-fifth of waste generated by coal-fired power plants was reused, and "the remaining four-fifths are typically disposed in surface impoundments or landfills." Id. at ES-2. The Report thus validates witness Kerin's testimony that "unlined basins were the industry standard" at that time. Tr. Vol. 24, pp. 128-29. As he stated, "the EPA report focused on new landfills and surface impoundments, while DEC last constructed a new ash basin in 1982." Id. at 129 (emphasis in original). This was six years before the EPA Report was submitted to Congress. As witness Kerin stated further, in the DEP case AGO witness Wittliff 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.'" Id. at 122. Finally, witness Kerin's conclusion is supported by the preamble to the CCR Rule itself. See Public Staff Kerin Cross-Examination Ex. 4.

Based upon similar evidence in the DEP case, the Commission found that "[s]ince the 1950s, standard industry practice at least in the Southeast, has been to deposit in coal ash basins, and such basins were constructed and used at all of the Company's coal-fired generating units." 2018 DEP Rate Order, p. 142. This finding and witness Kerin's testimony are also consistent with the Commission's findings in the 2016 DNCP Rate Order: "DNCP, like many electric utilities in the United States, has for decades generated electricity by burning coal. During those decades, the widely accepted reasonable and prudent method for handling CCRs has been to place them in coal ash landfills or ponds (repositories)." 2016 DNCP Rate Order, p. 60.

It is undisputed that there will be a natural flow from an unlined basin into groundwater. This is a function of basic science. Tr. Vol. 13, p. 58. As Company witness Wells testified:

> Earthen basins and dike walls are prone to the movement of liquid through porous features within those structures through a process known as seepage. Such seepage is common, and, to a degree, is necessary to maintain the stability of an earthen dam or dike wall; otherwise they become saturated, which may reduce margins of safety with respect to their structural integrity.

Tr. Vol. 24, p. 246. Accordingly, seepage from the Company's unlined ash basins – basins that complied with industry standards and the then-applicable regulatory requirements – is part of the "normal operation" of the basins. This evidence of the Company's historical compliance establishes that, except in limited fashion, its past coal ash management practices did not cause it to incur in the January 1, 2015 – December 31, 2017 timeframe unjustified costs to comply with current laws and regulations. Tr. Vol. 14, pp. 100-01.

Second, witness Kerin's testimony established that in large measure the costs were reasonable and prudent. In light of the evidentiary presumptions and shifting burden of production and persuasion, and based on the Commission's assessment of the credibility of the witnesses opining on the facts and policy considerations at issue, the Commission relies heavily on his testimony. The testimony of other Company witnesses, including witness Wells, will be discussed in greater detail in the sections of this order dealing with the Public Staff's specific disallowance recommendations. Witness Kerin's testimony was credible, demonstrated command of the subject matter (he testified, after all, that he had "lived" with that "company-specific subject matter every day for the past four years" (Tr. Vol. 24, p. 92), and the Commission determined in the 2018 DEP Rate Order that he has "'lived' this project since its inception," (2018 DEP Rate Order, p. 187), and the Commission concludes that his conclusions were not dislodged after being subjected to vigorous cross-examination.

Third, witness Kerin's testimony establishes that the capitalized costs for which the Company seeks recovery are eligible for a return and, at least to the extent they are capital in nature, were used and useful. These costs were expended to comply with the CCR Rule and CAMA, along with consent agreements that require the Company to implement corrective actions consistent with either or both of those regulatory requirements. Tr. Vol. 14, p. 115. 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, and, as indicated in the testimony of Company witness Wright, are routinely recoverable in rates. Tr. Vol. 14, p. 115; Tr. Vol. 12, p. 131. Further, witness Kerin's testimony (see Tr. Vol. 14, p. 135 and Kerin Ex. 10 and Ex. 11) details the "core components" of the costs incurred. These include, for example:

- With respect to the Allen and Belews Creek Plants' coal ash basins, oversight and environmental health and safety (EHS) activities, engineering and basin closure projects;
- With respect to the Buck Plant's coal ash basins, EHS activities, basin closure costs, mobilization and beneficiation costs;
- With respect to the Cliffside Plant's coal ash basins, mobilization and infrastructure costs, water management, ash processing, basin support projects, inspections and maintenance, and EHS activities;
- With respect to the Dan River Plant's coal ash basins, mobilization and infrastructure costs, water management, ash processing, landfill construction, engineering closure costs, and EHS activities;
- With respect to the Marshall Plant's coal ash basins, EHS activities, inspections and maintenance;
- With respect to the Riverbend Plant's coal ash basins, ash processing, water management, and EHS activities; and
- With respect to the W.S. Lee Plant's coal ash basins, mobilization, ash processing, and engineering closure plans.

Witness Kerin testified further that mandated closure of the existing coal ash basins meant that the modifications had to be made to their associated power plants, so as to direct storm water flow away from the ash basins and to cease bottom ash and fly ash sluice flow to the basins. Tr. Vol. 14, p. 133. In addition, other process streams must be directed away from the coal ash basins to facilitate de-watering and closure. Id.

Witness Kerin and his supporting exhibits describe costs expended to facilitate the Company's handling and storage of coal ash, so as to conform to the new legal requirements imposed on the Company resulting from the promulgation of the CCR Rule and the passage of CAMA. DEC is subject to these new legal requirements and must handle and store coal ash in a manner that complies with them. As such, except as detailed below, the capital costs of compliance are "used and useful," and the Company is authorized to recover them along with other costs accounted for in the ARO, along with a return as adjusted below on its outlay of these funds.

1. Intervenor Challenges to Cost Recovery

Intervenors have mounted challenges to the Company's recovery (with a return) of its already-incurred coal ash basin closure costs on two levels. First, in a manner that departs from the prudence framework the Commission established in the 1988 DEP Rate Case, the AGO, through witness Wittliff; CUCA, through witness O'Donnell; and the Public Staff, through witness Maness, all advocate that costs be disallowed even without a detailed analysis of the specific costs the Company has submitted for recovery.[61] Second, the Public Staff (and only the Public Staff) proposes to disallow specific costs incurred through the testimony of witnesses Garrett and Moore, and Junis, thus at least attempting to follow the Commission's prudence framework.

However, the Commission determines that these approaches are not appropriate, and these proposed specific disallowances are not approved.

2. <u>AGO/CUCA Approach: The Company "Caused" CAMA</u>

At the hearing, in response to questions by counsel for the Company, witness Wittliff admitted that, while his testimony stated that he would support a Commission finding that the coal ash costs incurred by DEC were unreasonable and imprudent, his actual position is that the Company should be able to recover its costs to comply with the CCR Rule, but nothing more. Tr. Vol. 11, pp. 279-81. He stated that costs incurred by the Company to comply with the CCR Rule are reasonable and prudent. <u>Id.</u> at 282-83. In contradiction to its witness, the AGO in its brief asserted that all the CCR cost recovery DEC seeks in this case is imprudent. Not only has the AGO been unable to quantify the costs DEC should have incurred prior to 2015, it has failed to sponsor a witness that can support its theory of the case. While purporting to represent consumers, the AGO's theories and recommended disallowances are inconsistent with those of the Public Staff, tasked with representing the same constituency.

Witness Wittliff admitted that he did not identify any specific costs that could have been lower or should be disallowed. <u>Id.</u> at pp. 287-89. However, witness Wittliff continued to pose the theory that the Company "caused" CAMA, and while he cannot point to imprudent action on the part of DEC in undertaking to comply with CAMA, the fact that the Company "caused" the statute to be enacted affects its ability to recover its CAMA-related costs. Tr. Vol. 11, pp. 239, 248-50, 272. CUCA witness O'Donnell agrees. Tr. Vol. 18, pp. 59-60 (Company caused CAMA and therefore should not recover any CAMA cost).

In these witnesses' view, CAMA sets a more aggressive coal ash basin closure schedule for certain of the Company's basins than would have been set under the CCR Rule alone, and the more aggressive schedule leads, again in their view, to higher costs. Witness Wittliff testified that he "[didn't] know quantitatively, because [he] didn't do that kind of analysis," in regard to what costs the Company would have eventually been

[61] Sierra Club witness Quarles asserted that continued storage of coal ash at Allen and Marshall poses significant environmental risks, and concluded that closure in place at these basins would allow continued contamination of downgradient groundwater and violate the technical standards of the CCR Rule, and that removal of coal ash from DEC's ash basins would reduce the concentrations and extent of this contamination. Tr. Vol. 6, pp. 17-118; 119-27. Witness Quarles made no effort to quantify the economic impact of his recommendation, which would <u>increase</u> cost to customers. The Commission is persuaded by the evidence presented by witness Kerin and witness Moore that the closure plans for the Allen and Marshall Plants are appropriate. DEQ will be responsible for determining which closure plans are appropriate for Allen and Marshall. The Commission determines that the associated expense for Allen and Marshall is reasonable and prudent.

required to undertake by the CCR Rule and CAMA, despite any exceedances, violations, criminal prosecutions, and civil and administrative lawsuits. Tr. Vol. 11, pp. 282-83.[62] Accordingly, the Commission determines that witness Wittliff's opinion cannot legitimately support disallowances, because it fails with respect to the prudence review framework the Commission established in the 1988 DEP Rate Case: (1) it fails to identify specific and discrete instances of imprudence; (2) it fails to demonstrate the existence of prudent alternatives; and (3) most importantly, it fails to quantify the effects by calculating imprudently incurred costs.

Witness O'Donnell proposes a 75% disallowance, but he does so predicated not on a calculation of "imprudently incurred costs" as required by the Commission's framework, but rather based on what he terms a "financial analysis" through comparison of the size of the ARO established by the Company to capture coal ash basin closure expense associated with CCR Rule and CAMA compliance with the AROs established by other utilities to capture their coal ash basin closure expense. This "calculation" is unpersuasive, however, as demonstrated by witness Kerin, (see Tr. Vol. 24, pp. 124-28), and as the Commission determined in the DEP case. See 2018 DEP Rate Order, p. 196. In particular, the analysis lacks any attempt by witness O'Donnell to account for the differences in which different utilities may have valued their closure cost estimates, or the differences in the timing of their estimates. As the Commission held in the 1988 DEP Rate Order, industry comparisons, even if relevant, are "of little value in determining specific acts of imprudence." 1988 DEP Rate Order, p. 56. The Commission agreed with the Company's witness that "[t]he flaw in industry comparisons … is that there are unique conditions on every nuclear project so that no projects are exactly comparable" (id.), and the same applies to AROs established by different utilities to capture their specific coal ash basin closure costs. Witness Kerin indicates, and the Commission agrees, that this renders witness O'Donnell's "analysis" without significant probative value – it is not a true apples-to-apples comparison of the utilities' AROs.

A more fundamental reason demonstrates why the Commission determines it should not accept the opinions of witnesses Wittliff and O'Donnell – the notion that the Company was the direct cause of CAMA is of limited legal basis. Witness O'Donnell presents no evidence of such direct causation, and witness Wittliff appears to base his opinion on a draft preamble to the Senate bill (Tr. Vol. 11, pp. 240, 248-50), notwithstanding the fact that this preamble is not present in the final ratified bill.[63] Moreover, in North Carolina, legislative intent is ascertained by the plain words of the statute. Rhyne v. K-Mart Corp., 149 N.C. App. 672, 562 S.E.2d 82 (2002). "Legislative history" of the type seemingly relied upon by witness Wittliff is legally impermissive. In State v. Evans, 145 N.C. App. 324, 550 S.E.2d 853 (2001), the Court stated:

[62] The AGO complains that the Commission imposes an inappropriate burden upon it to offer evidence to quantify the disallowances it advocates. The AGO cannot legitimately assert that the burden is unfair when it has failed to undertake the task of attempting to elicit that evidence. The AGO has undertaken substantial discovery of DEC in this case. Based on the omissions in its presentation, the AGO apparently failed to "close the loop" in seeking to elicit evidence on what it would have cost to take the remediation steps it alleges DEC should have taken prior to 2015.

[63] See N.C. Gen. Stat. § 130A-309.200, et seq.

> While the cardinal principle of statutory construction is that the words of the statute must be given the meaning which will carry out the intent of the Legislature . . . . [t]estimony, even by members of the Legislature which adopted the statute, as to its purpose and the construction intended to be given by the Legislature to its terms, is not competent evidence upon which the court can make its determination as to the meaning of the statutory provision.
>
> Thus, "[e]ven the commentaries printed with the North Carolina General Statutes, which were not enacted into law by the General Assembly, are not treated as binding authority by this Court." Accordingly, press releases and commission recommendations offered by defendant as evidence of the punitive purpose behind [the statute] are in no manner binding authority on this Court.

145 N.C. App. at 329-30, 550 S.E.2d at 857 (citations omitted). Accord. Elec. Supply Co. of Durham v. Swain Elec. Co., 328 N.C. 651, 657, 403 S.E.2d 291, 295 (1991); Styres v. Phillips, 277 N.C. 460, 472, 178 S.E.2d 583, 590 (1971) ("The intention of the legislature cannot be shown by the testimony of a member; it must be drawn from the construction of its acts.").[64]

Even if the actions or inactions of DEC or one of its sister companies was a direct cause of CAMA as these witnesses allege, such direct causation alone is not sufficient legal basis for disallowing otherwise recoverable costs. If the North Carolina General Assembly had intended to give the Commission the authority to deny otherwise recoverable environmental compliance costs due to some punitive theory of causation, it could have said so – and it did not. The legislature does not operate in a vacuum. Rather, it operates within the context of N.C. Gen. Stat. § 62-133, in which prudently incurred costs are recoverable. Had it intended to disavow the routine cost recovery standard, it can be expected that the legislature would have had to do so explicitly. Accordingly, witnesses Wittliff and O'Donnell theories of punitive causation do not comport with the controlling law of this state.

3. The Public Staff's "Equitable Sharing" Concept

In this case, as in the 2018 DEP Rate Case, the Public Staff advocates an "equitable sharing" of coal ash basin closure costs. The Public Staff's equitable sharing

[64] In Styres v. Phillips, the Supreme Court also stated that "the rule is that ordinarily the intent of the legislature is indicated by its actions, and not by its failure to act." Styres, 277 N.C. at 472, 178 S.E.2d at 590. Accordingly, the suggestion through cross-examination questions by the AGO (see, e.g., Tr. Vol. 13, p. 22) that as CAMA does not contain an express provision mandating cost recovery of compliance costs, the General Assembly did not intend for the statute to allow such costs, is also without any basis. To the extent that any such evidence is competent, the most relevant evidence regarding the General Assembly's failure to act is the fact that on two separate occasions the General Assembly was presented with the opportunity to mandate non-recoverability of compliance costs, and on both occasions the provision so stating did not pass.

proposal is supported by witness Maness. Tr. Vol. 22, pp. 70-85. Witness Maness achieves the sharing in the same manner in which he implemented the Public Staff's 50-50 sharing proposal in the 2018 DEP Case. First, he removes the unamortized coal ash basin closure costs from rate base, thereby, through that step, eliminating any return on that unamortized balance. Id. at 72. The second step is to choose an amortization period that will result in the desired level of "sharing." Id. The sharing level that the Public Staff and witness Maness deem "equitable" is 51% to the Company and 49% to customers. Id. at 84. Mathematically that results in a 27-year amortization period (id.), although, when adjusted for the rate of return to which the Company and the Public Staff agreed, subject to the Commission's approval, was appropriate in this case, the amortization period is reduced to 25 years. Id. at 153. Even under the 25-year amortization period, however, the sharing level remains 51% to the Company and 49% to customers. Id. at 162.

The Commission chose not to accept the "equitable sharing" concept in the 2018 DEP Case, and does so again, on the same basis.

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.

Black's Law Dictionary defines an "arbitrary and capricious" decision as one which, inter alia, is "without determining principle." See Tate Terrace Realty Investors, Inc. v. Currituck Cty., 127 N.C. App. 212, 222-23, 488 S.E.2d 845, 851 (1997). The Commission can discern no "determining principle" in the Public Staff's "equitable sharing" proposal. As such, were the Commission to adopt it, the Commission's action would be subject to an arbitrary and capricious attack and likely subject itself to reversal. An illustrative case is Sanchez v. Town of Beaufort, 211 N.C. App. 574, 710 S.E.2d 350 disc. review denied, 365 N.C. 349, 718 S.E.2d 152 (2011), in which the Court held that it was arbitrary and capricious for a municipal body to "cherry pick" a standard without providing any basis of any particular determining principle. Sanchez, 211 N.C. App. at 580, 710 S.E.2d at 354. In this case, the Beaufort Historic Preservation Commission (BHPC) attempted to limit the construction of petitioner's home to 24 feet in height "without the use of any determining principle from the BHPC guidelines." Id. at 582, 710 S.E.2d at 355. Rather, the BHPC members based the standard "on their own personal preferences," with each member providing a manner of re-working the project's construction to comply with a 24-foot height maximum, but none providing a reason as to why 24 feet when the height "could be a different number …." Id. at 581 (emphasis in original). Thus, while the BHPC members could provide a way to arrive at the height maximum, they could not provide a "why" for that particular height maximum. Failure to provide a determining principle for the height maximum itself rendered the BHPC's decision arbitrary and capricious. Id. at 582.

Ultimately, the Public Staff, through witness Maness, indicates that "what is and what is not allowed in rate base is within the legal discretion of the Commission to decide." Tr. Vol. 22, p. 73. The Public Staff overstates the Commission's discretion, and to the extent the Commission possesses such discretion, the Commission chooses not to exercise it in the manner the Public Staff advocates. To understand exactly how, it is necessary first to examine the Public Staff's purported rationales for its sharing proposal. There are two: first, the Company's alleged past failures, as detailed in the testimony of Public Staff witness Junis, to prevent environmental contamination from its coal ash basins, and, second, an asserted "history of approval of sharing of extremely large costs that do not result in any new generation of electricity for customers." Id. at 71-72.

As to the first asserted predicate, the Company disputes such "failures," as set out in the testimony of Company witness Kerin. The Commission credits Kerin's testimony, as detailed below, but whether or not the Company were guilty of some sort of violation is insufficient to justify the Public Staff's 51/49 sharing proposal. Witness Maness admitted that these alleged acts or failures to act are related to past operations. Tr. Vol. 22, p. 80. No persuasive evidence exists that any of these actions or inactions caused discrete expenditures by the Company to comply with its CCR Rule and CAMA obligations, which are the costs that the Company seeks to recover. Past actions, even if imprudent in this context must result in quantifiable costs, which the Public Staff has not shown. Therefore, identification of an imprudent action or inaction is not by itself sufficient; rather, there must be a demonstration of the economic impact. 1988 DEP Rate Order, p. 15. The Public Staff has made no such demonstration in this case, and no such demonstration with respect to the Public Staff's 51/49 sharing arrangement.

Apart from his specific recommendation regarding disallowance of groundwater remediation expense (discussed below), witness Junis' testimony does not link the past actions of the Company to the costs it seeks to recover. As Company witness Wright indicates, to link alleged past "violations" to current compliance costs in the factual context of this case is to "put the Company in an untenable situation." Tr. Vol. 13, p. 39.

Past violations may well be imprudent, but with respect to the "question of responding to new regulations and new standards, that is a totally separate question." Id. The Commission agrees with this distinction. In keeping with its decision in the 1988 DEP Rate Order, this aspect of which was affirmed by the North Carolina Supreme Court, to permit disallowance there must an actual expenditure shown to be imprudently incurred.

The Public Staff's position, simply stated, is that it does not matter if the Company's actions in incurring the CCR Rule and CAMA compliance costs were prudent – the Public Staff's equitable sharing proposal would still apply. As witness Maness testified, "[E]ven if 'prudent'" (Tr. Vol. 22, p. 126), the Public Staff would still find it "appropriate to have the shareholders of those companies bear a greater share of the cleanup costs under an equitable sharing approach." Id. Accordingly, the predominant rationale for the Public

Staff's proposal is witness Maness' second predicate: the proposition that the Commission has a "history of approval of sharing of extremely large costs that do not result in any new generation of electricity for customers." Id. at 72.

Witness Maness overstates his position – as witness Wright notes, there is "no provision of Chapter 62 requiring different treatment for 'extremely large costs'" (Tr. Vol. 12, pp. 156-21–156-22), and, witness Wright detailed any number of "extremely large cost" items not associated with new generation for which cost recovery is routinely allowed. Id. The Commission determines that this is another example of the arbitrariness inherent in the Public Staff's sharing proposal.

It appears that witness Maness' rationale for the sharing proposal is grounded in the Public Staff's view of the discretion available to the Commission. He states first that pursuant to N.C. Gen. Stat. § 62-133(b)(1), and with the exception of construction work in progress under certain circumstances, "the only costs that the Commission is required to include in rate base are … the 'reasonable original cost of the public utility's property used and useful, or to be used and useful within a reasonable time after the test period ….'" Tr. Vol. 22, p. 73. He indicates that he is advised by counsel that "beyond these requirements what is and what is not in rate base is fully within the Commission's discretion to decide, as long as the rates set thereby are fair and reasonable to both the utility and the consumers." Id.

DEC and the Public Staff stridently debate whether the 2015-2017 CCR remediation costs if found used and useful and otherwise meet the test for amortization with a return on the unamortized balance "must" or "may" be approved. The Public Staff argues that approval of a return is discretionary. The Commission determines it unnecessary to determine whether the costs must receive a return on the unamortized balance. In its discretion, as expressly authorized by N.C. Gen. Stat. § 62-133(d), with the exception addressed below, it approves a return.

DEC argues that deferred 2015-2017 CCR remediation costs accounted for in an ARO as authorized by the Commission in its 2018 order should be amortized over five years and should earn a return on the unamortized balance. The Public Staff argues that these ARO costs should be amortized over 25 years with no return based primarily on an equitable sharing theory. In support of these parties' contrasting positions and in order to challenge the merits of their opposition, the parties laboriously debate issues of used and useful, "entitled" versus "eligible" for earning a return, plant in service versus working capital, capital costs versus expenses, etc. The parties arduously debate the applicability to this issue of cases addressing an abandoned sewage treatment plant, costs of discontinued nuclear projects, and manufactured natural gas remediation costs.

No witness argues that the Commission lacks the discretion to follow the precedent it established in the two previous cases, DNCP and DEP, where it addressed the issue of amortizing deferred ARO CCR remediation costs over five years and a return on the unamortized balance. No witness argues that the law forbids the Commission to authorize a return on the unamortized balance. The Commission chooses to exercise its discretion and authority under N.C. Gen. Stat. § 62-133(d) and follow its precedent here - amortize the ARO costs over five years and authorize a return on the unamortized balance. The Commission will address the lengthy arguments and debate, but determines that by and large the arguments are not particularly germane or dispositive to the Commission's decisions. The Commission will not accept the Public Staff equitable sharing argument primarily because the Commission determines in its discretion that amortization of the deferred ARO costs over 25 years is inequitable and finds inadequate support for a 50-50 or 51-49 sharing versus some other ratio. The justification for disallowance of 50% of the ARO costs is not persuasive. The Commission concludes that the Public Staff relies on the equitable sharing principle because it, like other Intervenors, has been unable to quantify a disallowance on the basis of the alleged DEC acts and omissions prior to 2015 providing the predicate for the requested disallowance. Instead, the Commission relies upon some of the evidence offered to support the equitable sharing theory to impose a management penalty as discussed below.

While arguments by the parties through analogy to cases on other issues provide some helpful context, the issue of amortization of deferred CCR remediation costs required to comply with EPA CCR requirements and CAMA is sui generis and distinguishable. These expenditures, as FERC and GAAP refer to them, are "costs" or an "asset" of remediation. They have been deemed by the Commission without objection as extraordinary, as not being recovered through current rates and have for those reasons been deferred. As such, they are investor-supplied funds, not ratepayer-supplied funds and under principles of equity, law and fairness are eligible for a return. Otherwise the investor supplying these funds is deprived of the time value of money and is inadequately compensated resulting in an increased risk and ultimately increasing the Company's cost of capital. The Commission in its discretion hereby authorizes a return, but discounts it as discussed below.

The nuclear discontinued plant costs, to the extent relevant to the issues in this case, are primarily so with respect to the Public Staff argument in support of equitable sharing. The Commission determines on balance that the support for equitable sharing the Public Staff argues these cases provide is unpersuasive. This is not to say that the Commission is of the opinion it could not approve an equitable sharing remedy in a given case outside the context of a nuclear plant discontinuance case, but this is not a nuclear plant discontinuance case and not one the Commission chooses to rely upon to authorize equitable sharing. The costs the electric utilities incurred at issue in those cases were for nuclear plants, that had they been placed on line and generated electricity would have been added to rate base as used and useful plant in service. Some of the costs were for plants actually placed on line but sized to serve more units than the units actually generating electricity and therefore constituted excess capacity or plant not "useful." The costs had never been placed in rate base as plant in service prior to the general rate cases at issue, and to the extent they were costs in abandoned nuclear facilities, they were facilities never used to generate electricity. Those are not the facts at issue here. None of the nuclear plant discontinuance cases either before the Commission or the courts on appeal held that to the extent a portion of the costs could be recovered, they were ineligible for any return on the undepreciated balance, just that the costs should not be added to rate base. In fact, in the past, the Commission has approved a return. Order dated September 24, 1982, Docket No. E-2, Sub 444. (Commission authorized recovery of costs associated with cancelled Harris Units 3 and 4 over a ten-year period with inclusion of the interest arising from the debt financing portion of the unamortized balance.)

The costs of the sewage treatment plant at issue in Carolina Water were classified as abandoned plant. The plant long having been in service had been taken out of service, and it would never be used again because service would be provided by contract with a governmental agency. A portion of the original costs to build the plant had not been recovered through depreciation at the time of abandonment. That is not the factual situation in this case. Here there is a deferral of ARO CCR remediation costs. New costs were incurred in 2015-2016 in addition to creation or maintenance of the impoundment in prior years.[65]

The MFG case is somewhat analogous, but does 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. 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. The MFG case was a Commission decision, one the Commission may follow or not as it determines appropriate. For reasons fully explained herein, it determines not to follow it.

As to Public Staff arguments that the ARO costs or assets were all "capitalized expenses," the Commission, were it necessary to resolve this issue, would disagree. For example, a significant portion of the costs compiled in the asset retirement obligation has been or will be spent on creation of lined landfills with synthetic liners or impermeable caps over existing impoundments. These structures are examples of long-lived assets and are capital in nature- not expenses. Another significant portion, had they not been accounted for in an ARO and deferred, would have been operating or other expenses.[66] However, while expenditure of costs outside of the ARO context that are deferred may

[65] The issues of earning on the abandoned wastewater treatment plant was not the major issue before the Court in the Carolina Water case. The ultimate issue before the Commission was whether the unrecovered costs of the sewage treatment plant should be treated as plant held for future use of abandoned plant. Discussion of this issue consisted of less than two pages in a 126-page order. The monetary consequences amounted to a few thousand dollars per year. Docket No. W-354, Sub 111, Order dated July 31, 1992, pp. 56-58. The facts at issue in the case are unlikely to be repeated. Under the Uniform System of Accounts, the costs of individual components, in many instances, are combined into classes for calculating depreciation rates and net salvage value. Within these classes many individual components retire before or after the end of their projected useful lives. These retirements affect the recalculated depreciation rates, but the individual components are not classified as abandoned plant. See Tr. Vol. 2, Doss Ex. 3. Hahne & Aliff, Accounting for Public Utilities § 6.04 pp. 6-8, 6-10, § 6.05[3] pp. 6-12.

[66] 2016 is the twelve month test year in this case. To the extent the Commission had not authorized deferral of the ARO in 2016, the non-capital portion of the CCR remediation costs to the extent reasonable and prudent would be recoverable dollar-for-dollar in the revenue requirement. The portion spent on capital projects to the extent comprising completed projects would be added to rate base and eligible to earn a return.

include what otherwise would be classified as "expenses," e.g., operating costs, when they are capitalized and by order of the Commission are deferred, they lose for ratemaking purposes the attributes of test year recurring "expenses" deemed recoverable through the rates then in effect that do not qualify for a return. To the extent they qualify for recovery "of" (versus recovery "on") test year expenses in a general rate case through N.C. Gen. Stat. § 62-133(b)(3), they are recoverable as "actual investment currently consumed through reasonable actual depreciation" (amortization) rather than traditional test year, recurring "reasonable operating expenses." The Commission determines that while sui generis these ARO costs in totality are more closely related to deferred production plant costs than deferred storm damage costs, for example.

In Footnote 2 on page 5 of the Public Staff brief, the Public Staff contends:

> [2] Thornburg I provides that the Commission has discretionary authority to award or deny a return on the unamortized balance. A subsequent decision of the North Carolina Supreme Court indicates such deferred operating expenses are not eligible for a return on the unamortized balance: "Costs for abandoned property may be recovered as operating expenses through amortization, but a return on the investment may not be recovered by including the unamortized portion of the property in rate base." State ex rel. Utils. Comm'n v. Carolina Water Serv., 335 N.C. 493, 508 (1994) (Carolina Water Service). This decision did not expressly overrule Thornburg I, but nonetheless suggests that a return on unamortized balance of a regulatory asset is not a discretionary matter for the Commission; instead it may be prohibited by law.[67] For purposes of the present Post-Hearing Brief, the Public Staff position is that under either the Thornburg I holding or the Carolina Water Service holding, there is no DEC entitlement to a return on the unamortized balance of its deferred coal ash costs.

The Commission finds the contention inaccurate that the cited cases deny the Commission discretion to authorize a return on a deferred CCR remediation ARO. The nuclear plant discontinuance costs at issue in Thornburg I were not "deferred operating expenses" like deferred CCR ARO costs, and the abandoned water treatment plant costs

[67] While the Public Staff suggests that authorizing a return on the unamortized balance might not be discretionary, this suggestion is belied by the Public Staff's alternative remedy for disallowing CCR remediation costs set forth on page 422 of its proposed order:

> Consequently, the Commission in the exercise of its judgment and discretion, determines that a management penalty in the approximate sum of $72.3 million is appropriate with respect to DEC CCR remediation expenses accounted for in the earlier established ARO with respect to costs incurred through the end of the test year as adjusted. . . . Had the Commission not imposed this penalty, the deferred coal ash costs would have been amortized over five years with a full authorized return on the unamortized balance. The penalty will be imposed by reducing the resulting annual amortization expense by approximately $14.46 million (from the return on the unamortized balance in the rate base portion) for each of the five years, resulting in an approximate $72.3 million management penalty.

at issue in Carolina Water likewise were not deferred "regulatory asset" costs comparable to either deferred nuclear plant discontinuance costs or deferred CCR ARO costs.[68] The Commission notes that it has authorized deferral of capital costs in utility plant (e.g., combined cycle natural gas fired electric generating plants) completed and placed in service prior to the test year or prior to the end of the test year of a general rate case to prevent loss of recovery of costs. The costs so deferred are not test year recurring operating expenses but deferred capital costs, added to rate base and eligible for a full return. A used and useful analysis is appropriate to determine recovery of these costs. Docket No. E-22, Sub 532 (Dec. 22, 2016) (2016 DNCP Rate Order)

The Public Staff also argues inaccurately and misleadingly that “it generally makes no regulatory sense to defer to a regulatory asset a cost that could be placed in rate base – deferral is used when necessary to prevent significant erosion of earnings, which is applicable to expenses but not to property that can be put in rate base; . . . .” In the Commission’s December 22, 2016 order in the most recent DNCP general rate case, Docket No. E-22, Sub 532, the Commission approved a stipulation between the Company and the Public Staff to defer the post-in-service costs of the Warren County CC and the Brunswick County CC. These plant-in-service electric production assets had been placed in service prior to the end of the general rate case test year, and the deferral postponed the date on which depreciation costs began and permitted return on the full costs of the assets. This deferral related to property, not expenses.

From the outset, the Public Staff has acknowledged and recognized that the ARO costs do not fit into traditional categories: "The Public Staff believed that the non-capital costs and depreciation expense related to compliance with state and federal requirements ... these very unique deferred expenses . . . the unusual circumstances of these costs . . . the unique nature of the costs and the complexity of the issues surrounding the determination of ultimate rate recovery." Tr. Vol. 18, pp. 300-01, Docket No. E-2, Sub 1142.

In the Commission's attempt to obtain a classification of the types of costs included in the ARO in the DEP case, witness Maness listed among others, site preparation, site infrastructure, construct a landfill, cap-in-place, capital expenditures related to equipment and facilities." Tr. Vol 19, p. 58. Under any analysis, these are not expenses but capital items. Had DEC not sought establishment of an ARO and deferral, it is incorrect that they would not have been added to plant in service and depreciated over their useful lives.

[68] While the regulatory accounting concepts of creation of a “regulatory asset/liability” and “deferral” include a wide spectrum of cost categories, this Commission views differently costs incurred before the test year of a general rate case (like extraordinary storm costs) and costs otherwise recognizable as test year costs or expenses but deferred for non-traditional future recovery such as nuclear plant discontinuance costs that are not added to rate base but are nonetheless amortized over future years. Costs in the former category are deferred to prevent loss of recovery. Costs in the latter category generally are deferred to limit, reduce or postpone recovery.

In Docket No. E-2, Sub 1142, witness Maness was asked why certain ARO capital costs were not appropriately classified as used and useful.

Q. Just to be clear, one of the things we are doing -- we showed it up on the screen here yesterday - we are putting liners under these coal ash pits, right?
A. Yes, sir.
Q. And that's - and we are putting caps or proposing to put caps over some coal ash basins?
A. Yes.
Q. Isn't that used and useful expenditure to keep the coal ash where it belongs?
A. Well, that raises a number of interesting questions, and I can't pretend to be able to answer them in detail. I have been searching for some answers in the accounting literature and haven't found anything direct yet."

Tr. Vol. 19, pp. 65-66.

Upon being questioned and when given the opportunity to support its position that the deferred ARO costs are "expenses," the Public Staff simply was unable to do so.

When witness Maness was asked whether classifying the ARO costs as used and useful made any difference to the outcome of the case, he responded, "I don't think it makes any difference in this case." Tr. Vol. 19, p. 66. The Commission agrees.

The Commission does agree with the Public Staff and others that even if the ARO deferral costs are found used and useful and that a 9.9% rate of return on rate base is appropriate, the Commission nevertheless has authority to disallow a portion of the return on the ARO costs due to mismanagement. This is what the Commission has required, and it is legally justified in doing so.

As expressed through witness Maness' testimony, the Public Staff looks to the Commission's Order Granting Partial Increase in Rates and Charges in Docket No. E-2, Sub 526 (Aug. 27, 1987) (1987 DEP Rate Order) and its affirmance by the Supreme Court in Thornburg I, 325 N.C. 463, 385 S.E.2d 451 (1989) as precedent for its equitable sharing concept. The Commission determines that Thornburg I provides less support for the equitable sharing the Public Staff advocates when viewed within the context of other cases addressing nuclear plant discontinuance costs. Greater context is found in Thornburg II, the 1988 DEP Rate Order and the Commission's Order Denying Motions for Reconsideration in the 1988 DEP Rate Case (Docket No. E-2, Sub 537) (1988 DEP Reconsideration Order), and the Supreme Court's reversal in part of those orders in Thornburg II, 325 N.C. 484, 385 S.E.2d 463 (1989).

The principal issue in the 1987 DEP Rate Case/Thornburg I was whether the Company could recover in rates any portion of the costs associated with the abandoned Units 2, 3, and 4 of the Shearon Harris nuclear plant. The Commission had previously decided that the Company could amortize the costs associated with these abandoned units over a ten-year period, but that "no ratemaking treatment should be allowed which would have the effect of allowing … [the Company] to earn a return on the unamortized balance." 1987 DEP Rate Order, p. 61. Over the objections of the AGO, the Commission decided to continue to follow that process in the 1987 case – it allowed amortization of abandonment costs over a ten-year period, what the court classified as an operating expense[69] for the purposes of rate recovery under N.C. Gen. Stat. §§ 62-133(b)(3) and 62-133(c), but no return. The Supreme Court, in a passage extensively quoted in witness Maness' testimony (Tr. Vol. 22, pp. 75-76), affirmed the Commission's decision, holding that N.C. Gen. Stat. §§ 62-133(b)(3) and 62-133(c) were elastic enough to include non-recurring abandonment costs as utility test year "expense," and that N.C. Gen. Stat. § 62-133(d), which allows the Commission to factor in "all other material facts of record that will enable it to determine what are just and reasonable rates," also provided support for the Commission's decision. The Court further held that as a matter of policy a return of, but not a return on, the abandonment costs was appropriate. Thornburg I, 325 N.C. at 476-81, 385 S.E.2d at 458-61. The Commission had not authorized a return on the costs at issue. The contested issue was recovery of not recovery on the nuclear investment costs.

In Thornburg I, the Court held specifically that the Commission's recovery of but no return on decision was "within the Commission's discretion" and would not be disturbed. Id. at 481. That decision effected a "sharing" between the Company's shareholders, on the one hand, and its customers, on the other – shareholders received a return of the costs, but no return on the costs. It is based upon this holding that the Public Staff, through witness Maness' testimony, contends that "reasonable rates can include a sharing between ratepayers and investors with regard to plant cancellation costs" (Tr. Vol. 22, p. 75), and that the Commission possesses discretion to implement this sharing.

There are, however, distinctions between the 1987 DEP Rate Case/Thornburg I and the present case. First this case does not involve "abandoned plant" or cancellation costs. Rather, it involves an asset retirement obligation and whether or not the unamortized balance is eligible for a return. As such, the authority that the Public Staff relies upon to support its "equitable sharing" concept is not directly on point. This is illustrated by examining the prior orders of this Commission and the subsequent Thornburg case: the 1988 DEP Rate Order, the 1988 DEP Reconsideration Order, and Thornburg II.

In the 1988 DEP Rate Case, the principal issue for decision was the reasonableness and prudence of the costs of constructing and placing into service Unit 1 of the Shearon Harris nuclear plant. The Commission found that for the most part, Harris

[69] While the Court's use of the term "operating expense" is technically correct as referenced in the statute, the more precise term should have been "actual investment currently consumed through reasonable actual depreciation" (amortization) in N.C. Gen. Stat. § 62-133(b)(3). The costs at issue are not recurring operating and maintenance or other "expenses" expended in the test year. They are ever decreasing costs allowing a "return of," but not a "return on" the nuclear plant costs. See Tr. Vol. 9, pp. 115-131; Vol. 10, pp. 14-28.

Unit 1 costs were reasonable and prudent, and that determination in the 1988 DEP Rate Order was upheld by the Supreme Court. Thornburg II, 325 N.C. at 488-89, 385 S.E.2d at 465-66 (finding "no error" in that part of the Commission's Order). However, a part – $570 million-worth – of the costs the Commission considered were incurred in connection with facilities to be shared with Units 2, 3, and 4, units that the Company had ceased to construct to completion. The Commission found that while these $570 million in costs were prudently incurred, they should be shared between the Company's customers and its shareholders. The Commission found that approximately $180 million of those costs were properly classified as "abandonment" costs and should be borne by shareholders. 1988 DEP Rate Order, pp. 112-14. The remaining $390 million were left in rate base.

Responding to the Public Staff's request that the Commission reconsider this decision and remove the entire $570 million from rate base on the grounds that all of it related to abandoned plant, the Commission reaffirmed its decision in the 1988 DEP Reconsideration Order and provided additional explanation for its ruling. It stated that the Public Staff's request that the full $570 million for the common facilities be treated as abandonment costs was based upon a "misunderstanding" of the 1988 DEP Rate Order and the Commission's objective in splitting this $570 million item into $390 million of rate base and $180 million of cancellation costs. 1988 DEP Reconsideration Order, pp. 2-3. The Commission did not (it says in the 1988 DEP Reconsideration Order) intend to treat the "excess common facilities" as abandoned plant; rather, it effected an "equitable sharing" (emphasis added) of the $570 million between customers and shareholders. The Commission reiterated that the Company's choice of the cluster design – which engendered the shared facilities – was reasonable and prudent, and that except as specifically indicated in the 1988 DEP Rate Order, the costs of the Shearon Harris plant were "reasonable and prudently incurred." Thus, the Commission found, the $570 million at issue was also reasonably and prudently incurred.

Nevertheless, the Commission held, (id. at 4-5), that it was appropriate to share the $570 million at issue, and it indicated that it came up with the allocation (essentially one-third to cancellation costs and two-thirds to rate base) on its own and adopted it "for reasons of fairness and equity." The Commission held that it continued "to believe that a reasonable and equitable apportionment of the burden and risks associated with … [the Company's] prudent investment in common facilities is appropriate." It stated further that its assignment of $180 million as the value of the Company's prudent investment in common facilities to be treated as cancellation costs for ratemaking purposes was an appropriate exercise of its "regulatory discretion."

The Supreme Court disagreed. It held that the Commission did not have the discretionary power to effectuate its "equitable sharing" decision. Rather, the facilities were either "used and useful," and therefore in rate base, or they were not. The Court looked to the Commission's finding that the facilities in question were "excess common facilities," and held that "excess" facilities were not "used and useful" as a matter of law. Thornburg II, 325 N.C. at 495. Accordingly, looking to the broader spectrum of Commission and Supreme Court precedent, the Commission determines not to approve the Public Staff's "equitable sharing" concept through reliance on the nuclear plant discontinuance cost cases.

4. ARO Accounting and "Used and Useful"

In the 2018 DEP Rate Case, the Public Staff argued that the Commission had the discretion to implement the "equitable sharing" concept based upon the Public Staff's interpretation of prior Commission orders and decisions of the North Carolina Supreme Court that permit equitable sharing in the case of abandoned nuclear plants or long out-of-use manufactured gas plants. As noted above and in the 2018 DEP Rate Order, the Commission determines not to approve the Public Staff equitable sharing recommendation. In the 2018 DEP Case, the Commission held to the contrary that

> Costs placed in an ARO account are eligible for deferral and amortization and for 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 DEP Rate Order, p. 196. In this case, Public Staff disputes this as a matter of accounting, and concludes on the basis of its interpretation of the accounting standards that the Company's coal ash basin closure expenditures cannot be classified as "used and useful." As it did in the 2018 DEP order, the Commission determines that it can authorize a return on the unamortized ARO costs.

The Public Staff's position is advanced by witness Maness. Starting from the premise that the Company "chose" to account for its coal ash basin closure costs through ARO accounting, witness Maness makes three basic points. First, he indicates that the Company's deferred coal ash basin closure costs placed in the ARO are more properly categorized as deferred expenses, in that the ARO is "a regulatory accounting and ratemaking method that does not explicitly account for any coal ash compliance costs, either in the past or in the future, as the capitalized costs of property, but instead accounts for them as ongoing expenses …." Tr. Vol. 22, p. 79. Second, he states that the fact that the Company classifies these costs as "working capital" is irrelevant, and merely a matter of convenience. Id. at 81. Third, he asserts that these costs cannot possibly be classified as "used and useful," because (in his view) that term applies only to utility plant, not expenses. Id. at 77. The Commission disagrees, but as the Public Staff agrees that the Commission possesses the discretion to approve a return on the unamortized balance of the deferred CCR remediation ARO costs, the Commission finds the debate for purposes of this case to be for the most part an academic one.

First, the Commission disagrees that the Company "chose" ARO accounting. The Commission has already so held in the 2018 DEP Case: "Once it became clear that the new laws and regulations governing coal ash would require closure of the Company's existing coal ash basins, GAAP required that an ARO be established, and the Company had no choice in the matter." 2018 DEP Rate Order, p. 194.[70] Further, as Company witness Doss testified, in addition to GAAP requirements "the Company was also required to (and did) adhere to and apply the accounting guidance under … [the] Federal Energy Regulatory Commission ('FERC') Code of Federal Regulations ('CFR'), as well as Orders of this Commission." Tr. Vol. 12, p. 62. The Company's ARO accounting complies with the authoritative statements of GAAP, FERC, and this Commission.

Witness Doss provided an extended explanation of the GAAP, FERC, and deferral directives that govern the manner in which the Company established the ARO and has accounted for coal ash basin closure costs in the ARO. The Commission credits his explanation and testimony, which are un-contradicted.

a. GAAP

The CCR Rule and CAMA were new laws that compelled basin closure under GAAP.[71] As Company witness Doss indicated, "The closure obligation triggered ARO accounting requirements." Tr. Vol. 12, p. 63. He elaborated:

> Statement of Financial Accounting Standard ("SFAS") No. 143 (now codified as ASC 410) was effective for and implemented by the Company in 2003 for financial reporting purposes. This guidance requires recognition of liabilities for the expected cost of retiring tangible long-lived assets for which a legal retirement obligation exists. GAAP (in ASC 410-20-20) refers to these costs as an "Asset Retirement Obligation" or an ARO, and defines a "legal obligation" as an "obligation that a party is required to settle as a result of an existing *or* enacted law …." (Emphasis added). Each of CAMA and the CCR Rule qualify as an "enacted law" under this guidance.

Id. As he explained further (id. at 64-65), GAAP requires ARO accounting for the closure costs under ASC 410-20-15. Specifically, Subtopic 15-2 indicates that the guidance applies to the following transactions and activities:

a) Legal obligations associated with the retirement of a tangible long-lived asset that result from the acquisition, construction, or development and (or) the normal operation of a long-lived asset, including any legal obligations that require disposal of a replaced part that is a component of a tangible long-lived asset.
b) An environmental remediation liability that results from the normal operation of a long-lived asset and that is associated with the retirement of that asset. The fact that partial settlement of an obligation is required or performed before full

[70] As the Public Staff and the Commission have noted previously, "Statements of the FASB are officially recognized by the Securities and Exchange Commission (SEC) as authoritative with regard to GAAP in the United States, and the requirements included in those Statements are essentially mandatory for any publicly traded entity." See Order Granting in Part and Denying in Part Request for Deferral Accounting, Docket E-7, Sub 723 (April 4, 2003), pp. 11-12.

[71] The applicable GAAP guidance is contained in Doss Rebuttal Ex. 1.

retirement of an asset does not remove that obligation from the scope of this Subtopic. If environmental contamination is incurred in the normal operation of a long-lived asset and is associated with the retirement of that asset, then this Subtopic will apply (and Subtopic 410-30 will not apply) if the entity is legally obligated to treat the contamination.

c) A conditional obligation to perform a retirement activity. Uncertainty about the timing of settlement of the asset retirement obligation does not remove that obligation from the scope of this Subtopic but will affect the measurement of a liability for that obligation (see paragraph 410-20-25-10).

Here, the coal ash basins being retired are tangible long-lived assets, and so Subtopic 15-2(a) applies. In addition, to the extent that retirement involves any environmental remediation, that remediation is the result of the normal operation of the basins, which is the subject of Subtopic 15-2(b). As noted in Company witness Kerin's testimony, the use of ash impoundments as a storage location for coal ash and other CCR was in accordance with industry standards and then-applicable regulations. Finally, under Subtopic 15-2(c), the retirement requirements are a conditional obligation to perform a retirement activity as the nature, timing and extent of the closure depends on various determinations. In CAMA those determinations revolve around the legislative or the North Carolina Department of Environmental Quality assessed risk rankings. Under the CCR rule, those determinations revolve around the evaluation of certain criteria by specific deadlines.

Upon recognition that ARO accounting is required, GAAP further indicates that the entity "shall capitalize an asset retirement cost by increasing the carrying amount of the related long-lived asset by the same amount as the liability." ASC 410-20-25-5; see also Tr. Vol. 12, p. 20.

The reference in ASC 410-20-15-2(b) to environmental compliance costs in connection with "normal operation" highlights an important distinction in this case with respect to the Company's coal ash basin closure costs. GAAP distinguishes between costs associated with "normal" and "costs associated with improper" operation. The Company has demonstrated that "normal" operation applies.

The distinction is detailed in witness Doss' testimony. Subtopic 410-20 of the ARO guidance applies to "normal operation" (see ASC 410-20-15-2(b); Doss Rebuttal Ex. 1, p. 2 of 28), and permits their inclusion in an ARO. Subtopic 410-30 applies to improper operation (see ASC 410-20-15-3(b); Doss Rebuttal Ex. 1, p. 2 of 28), and excludes them from an ARO. For example, as witness Doss testified, "Costs associated with the Company's Dan River spill … are covered by Subtopic 15-3(b), and, therefore, are not included in the coal ash basin closure ARO." Tr. Vol. 12, p. 66. This comports with the GAAP guidance itself, which notes that "a certain amount of spillage may be inherent in the normal operations of a fuel storage facility, but a catastrophic accident caused by noncompliance with an entity's safety procedures is not." See ASC 410-20-15-3(b); Doss Rebuttal Ex. 1, pp. 2-3 of 28. The guidance notes further that the spillage costs are properly within the ARO, while costs resulting from the catastrophic accident are excluded. Id.

GAAP guidance notes that "whether an obligation results from the normal operation of a long-lived asset may require judgment." See ASC 410-20-55-7; Doss Rebuttal Ex. 1, p. 11 of 28. Witness Doss acknowledged this. Tr. Vol. 12, p. 111. But it is not unbridled or arbitrary judgment. To the contrary, the exercise of judgment is carefully circumscribed through internal and external controls.

Witness Doss described these controls at length in his testimony. He noted that "DEC has implemented a Coal Ash ARO Charging Committee whose purpose is to evaluate costs to be incurred for determination as to whether they qualify for ARO accounting treatment … [and that decisions] of the Coal Ash ARO Charging Committee are summarized in a charging guidelines document." Id. at 66-67. These decisions are reviewed internally by the Company's "Coal Combustion Products (CCP) group to ensure that 1) all relevant facts were appropriately communicated by CCP and understood by the Committee, and 2) that the CCP group understands the decisions to properly categorize actual project costs." Id. at 67. Finally, any ARO-related cost classification is also reviewed by the Company's external auditor, Deloitte & Touche LLP, which in the course of its annual audit issues its opinions that the Company's financial statements are presented fairly in all material respects and in accordance with GAAP, and that the Company has effective internal control over financial reporting. Id. at 67-68.

The Commission determines that the evidence that the coal ash basin closure costs incurred by the Company, and for which it seeks recovery in this case, result from the "normal," non-catastrophic operation of the Company's coal ash basins is compelling. It is detailed above in connection with the Commission's discussion of the Company's prima facie case, and need not be repeated. The Company has demonstrated that its coal ash management practices, storage of CCR in unlined ash basins, complied with the then-applicable regulations and with industry practice. Seepage from unlined basins is therefore part of the "normal operation" of those basins.

b. FERC

Witness Doss also explained the FERC accounting guidance. He noted that the Company is regulated by FERC, and therefore required to use the FERC Uniform System of Accounts, which states, in relevant part:

> An asset retirement obligation represents a liability for the legal obligation associated with the retirement of a tangible long-lived asset that a company is required to settle as a result of an existing or enacted law, statute, ordinance, or written or oral contract or by legal construction of a contract under the doctrine of promissory estoppel. An asset retirement cost represents the amount capitalized when the liability is recognized for the long-lived asset that gives rise to the legal obligation. The amount recognized for the liability and an associated asset retirement cost shall be

> stated at the fair value of the asset retirement obligation in the period in which the obligation is incurred.

Tr. Vol. 12, p. 68. He noted further that the FERC Uniform System of Accounts General Instruction No. 25 requires that:

> a utility initially record a liability for an ARO in Account 230 — Asset Retirement Obligations, and charge the associated asset retirement costs to the electric utility plant that gave rise to the legal obligation in Account 101- Electric Plant in Service. The asset retirement cost is to be depreciated over the useful life of the related asset that gives rise to the obligation by recording a debit to Account 403.1- Depreciation Expense for Asset Retirement Costs and a credit to Account 108 Accumulated Provision for Depreciation of Electric Utility Plant. In periods subsequent to the initial recording of the ARO, the utility shall recognize the period-to-period changes of the ARO that result from the passage of time due to the accretion of the liability by recording a debit to Account 411.10 — Accretion Expense, and a credit to Account 230.

Id. at 68-69.

Commission's Deferral Order and Summary of Accounting Rules and Deferral

In 2003, after the Financial Accounting Standards Board required the implementation of the ARO accounting guidance, the Commission ruled in Docket No. E-7, Sub 723 "That the implementation of SFAS 143 [now codified as ASC 410] for financial reporting purposes and the deferrals allowed in this docket shall have no impact on the ultimate amount of costs recovered from the North Carolina retail ratepayers for nuclear decommissioning or other AROs, subject to future orders of the Commission." See Order Granting Motion for Reconsideration and Allowing Deferral of Costs, Docket E-7, Sub 723 (August 8, 2003), p. 12. As witness Doss explains,

> The cash outflows to settle the ARO are not recorded as an expense of DE Carolinas. The Company has already recognized depreciation expense through the life of the asset and accretion expense over the period of expected settlement of the ARO, and these costs were capitalized previously as part of the Asset Retirement Cost related to the ARO. See ASC 410-20-25-5. However, in the case of DE Carolinas and pursuant to the Commission's Order in Docket No. E-7, Sub 723, the depreciation and accretion expenses were deferred. The amount spent related to the coal ash basin closure ARO is effectively the portion of the deferred depreciation and accretion expense which has now been incurred as a cash outflow and which is "subject to the future orders of the Commission" as stated in the Order. Therefore, the Company's deferral request of costs incurred and the recovery request in this rate case are in accordance with the deferral Order the Commission issued in Docket No. E-7, Sub 723.

Tr. Vol. 12, p. 70.

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. 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.

c. The Savoy Letter

The Company's accounting of its coal ash costs has not occurred in a vacuum. Over 20 months before DEC filed its application to increase rates in this docket, it sent a letter to the Commission, copying the Public Staff, in which the Company detailed exactly how it was accounting for its coal ash basin closure costs. See Letter dated December 21, 2015 from Brian D. Savoy, the Company's SVP, Chief Accounting Officer, and Controller to Gail L. Mount, Chief Clerk (Savoy Letter), filed in Docket No. E-7, Sub 1110.[72] The Savoy Letter:

- Describes the GAAP and FERC accounting requirements regarding AROs;
- Describes the triggering events for the creation of the ARO, noting the promulgation of the CCR Rule and the passage of CAMA;
- Indicates that an ARO related to the closure of coal ash basins was recorded on the Company's balance sheet;
- Indicates further that a corresponding asset was recorded "as part of the associated coal plant in the property, plant and equipment (PP&E) accounts, or if associated with a retired coal plant, recorded in regulatory assets"; and
- Noted that "[c]onsistent with the requirements of the Commission's Order dated August 8, 2003 in Docket No. E-7, Sub 723 … all income statement impacts relating to the AROs ultimately reside in regulatory asset accounts."

Witnesses Fountain and McManeus were examined at length regarding the Savoy Letter at the evidentiary hearing. Tr. Vol. 9, pp. 117-24. That examination established, inter alia,

[72] This Docket was established on March 28, 2016 by order of the Commission, and the Savoy Letter placed therein, so as to acknowledge the Letter and allow other parties with interest to be made aware of it. See Order Acknowledging Receipt of Filing, Docket No. E-7, Sub 1110 (Mar. 28, 2016). The order recited that no filings were made in response to the letter as of the time the Docket was established, and indeed, no substantive filings were made thereafter until the Company filed its Petition for Accounting Order on December 30, 2016, formally seeking deferral of coal ash basin closure costs. The Sub 1110 Docket has been consolidated with this rate case docket.

that basin closure costs, whether they be denominated capital costs, O&M costs, general administration costs are nevertheless capitalized in connection with the establishment of the ARO; that such costs are extraordinary and not reflected in the Company's then-current rates; and, therefore, needed to be set aside and deferred so that the Company would not lose recovery of those costs "to the detriment of the stockholder." Id. at 123-24.

No party takes issue with the Company's accounting of coal ash basin closure costs in an ARO, as detailed in the Savoy Letter. Certainly, the Public Staff does not – witness Maness' testimony does not challenge the basis for or the propriety of the accounting treatment, he comes to a different conclusion regarding the effect of such treatment upon the Company's entitlement versus its eligibility to earn a return on the unamortized balance of those costs. As noted previously, Intervenors have a burden of production when challenging the Company's costs. This principle equally applies to the accounting for costs. The Commission determines that the Company has met this burden. The Public Staff challenge makes the issue ripe for the Commission to address the issue on the merits. The Company has met its burden of showing that the costs it seeks to recover are not only reasonably and prudently incurred, but also appropriately accounted for in ARO accounting, and the Commission agrees that based on its determinations on the merits that recovery is appropriate except as addressed below.

Several consequences flow from this determination. First, deferred costs are costs "that have been paid for by the … [utility] but have yet to be included for ratemaking purposes …." Lesser & Giacchino, p. 52. Through the Savoy Letter, the Company told the Commission and the Public Staff, and the Commission told all interested parties, exactly how the Company's coal ash basin closure costs were being accounted for, and explicitly indicated that the costs were being deferred pursuant to the Commission's orders in Docket No. E-7, Sub 723. Neither the Public Staff nor anyone else, including the AGO, raised any objection.

Nor did the Public Staff or the AGO raise any objection when the Company made its formal deferral request in 2016. Tr. Vol. 9, p. 126. The Public Staff however asserts that deferral for regulatory accounting purposes is appropriate, given the magnitude of the costs and their potential impact upon the authorized rate of return. The nature of the deferral is such that all costs, no matter how classified, related to the Company's coal ash basin closure obligations are accounted for in the ARO. Id. p. 125. The ARO was established for this purpose, as the Savoy Letter makes clear. As such, the Commission determines that even were it necessary to resolve this issue, witness Maness' classification of these costs as "deferred expenses" is not persuasive, not supported by authority and not determinative, given the nature of deferral.

It is also incorrect as a matter of accounting. As witness Doss testified, "The Company has accounted for these costs as required under GAAP and FERC Uniform System of Accounts." Tr. Vol. 12, p. 71. Under GAAP, the costs (no matter what their classification) are capitalized pursuant to ASC 410-20-25-5. Id. at 70. Under FERC accounting, they are capitalized as well. Id. at 68-69. Accordingly, when properly accounted for in an ARO, the specific classification of costs is not determinative, because under GAAP and FERC guidance ARO costs are capitalized. The nomenclature relied upon in GAAP and FERC is costs, assets, and liabilities, not "expenses."

Likewise, witness Maness' criticism that these costs are placed in "working capital" is also not determinative. Witness Maness, without support and solely as a matter of opinion, states that the Company's inclusion of the deferred balance of coal ash basin closure costs in the "working capital" portion of rate base is merely a matter of convenience. Tr. Vol. 22, p. 81. He does not state that their inclusion in working capital is incorrect, merely that such inclusion is not determinative of the issue of whether the Company is entitled to a return on the unamortized balance. It appears that witness Maness has misunderstood the Company's position, as is evident from the testimony of witness McManeus, which the Commission also credits. She testified:

> [I]t is important to recognize that rate base represents the amount of funds supplied by investors. Such funds have been advanced for many purposes. Certainly, construction of electric plant is one such purpose, but there are others – for example, to purchase fuel inventory, to provide cash working capital, etc. Further, to accurately determine the amount of investor-supplied funds, one must consider whether any amounts that have been used for such purposes have been advanced by customers, rather than investors. In this particular case, investors have advanced funds to pay for coal ash compliance costs.

Tr. Vol. 6, p. 317. She elaborated further, indicating that the "characteristic that makes the deferred coal ash cost a legitimate component of rate base" is the fact that the funds used to pay those costs were supplied by investors. Id. at 318.

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, unless the Company should be penalized due to mismanagement, for example, and the Commission would act contrary to law were it to order them.

Finally, the Public Staff's notion that costs accounted for in an ARO, at least to the extent they relate to long lived capital assets, are expenses and therefore ineligible to be characterized as "used and useful" is inconsistent with ARO accounting, and also inconsistent with the law. The Commission has already decided that the Public Staff's legal position that "used and useful" property is confined to "plant" is incorrect. It held in the 2018 DEP Rate Case:

As a matter of law, it is not necessary that something be classified as "plant" in order to be properly included in rate base. Rather, the issue is the source of the funds. In State ex rel. Utils. Comm'n v. Virginia Elec. & Power Co., 285 N.C. 398 (1974) (VEPCO), for example, the Supreme Court held that working capital (which is not "plant") could be included in rate base, so long as it was provided by the utility:

> Like any other business, a public utility must at all times have on hand a reasonable amount of materials and supplies and a reasonable amount of funds for the payment of its expenses of operation. 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" … and are a proper addition to the rate base on which the utility must be permitted to earn a fair rate of return.
>
> Conversely, the utility is not entitled to include in its rate base funds which it has not provided but which it has been permitted to collect from its customers for the purpose of paying expenses at some future time and which it actually uses as working capital in the meantime.
>
> 285 N.C. at 414-15. As the Company appropriately accounted for coal ash basin closure costs in the working capital section of rate base, and as these funds were investor-furnished, not customer-furnished, VEPCO holds that they are "used and useful" within the meaning of N.C. Gen. Stat. § 62-133(b)(1) in the provision of service. As such, the Company is entitled to earn a return on those funds over the period in which the costs are amortized.

2018 DEP Rate Order, pp. 194-95.

In addition, however, witness Maness is incorrect in his view of the appropriate accounting outcome. He indicates, "It is appropriate to state that the actual costs capitalized by a utility as the costs of used and useful property itself may be included in rate base and thereby earn a return, as long as those costs are reasonable and prudently incurred, and are intended to provide utility service in the present or in the future; however, the expenses of operating and maintaining that property in the present or in the future do not get capitalized as part of the cost of the property." Tr. Vol. 22, pp. 77-78 (emphasis added.) It is less than clear what witness Maness means by this qualification.

However, as witness Doss testified, in ARO accounting, "Under both GAAP and FERC guidance the asset created when a Company initially recognizes an ARO is considered part of the property, plant and equipment for the assets which must be eventually retired." Tr. Vol. 12, p. 71 (emphasis added.) Accordingly, such costs are used and useful in that they 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. As witness Doss concluded, "The achievement of those three purposes is used and useful as the utility has the obligation to comply with CAMA and the CCR Rule." Id. at 73.

When the coal ash basins at issue in this matter were constructed, they were capital assets "used and useful" in the provision of service to customers – their function was to store coal ash, a byproduct of the generation of electricity. Even if closed as a result of CAMA and the CCR Rule, the basins at all but high priority sites will remain, although they may be capped in place or have other remedial measures taken to comply with the current regulatory requirements. As such, they will remain used and useful, because they will still store coal ash, a byproduct of electricity generation. The basins at high priority sites will no longer exist, but in the case of Dan River, a new landfill is being constructed, which is a capital asset and used and useful – it, too, will store coal ash. The landfill will have a long-lived synthetic liner, a cost that even outside the concept of ARO accounting is not an "expense." Other expenses of a more O&M or general administration variety were incurred yet deferred under the deferral orders of this Commission, meaning that the Company is afforded the opportunity to recover them in rates at a later time. The funds used to pay for those 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. 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 "deferral and amortization and for earning on the unamortized balance." The Commission so orders in this case.

The question to be decided is the amount of the funds so eligible. That depends upon the Commission's analysis of the reasonableness and prudence of the costs incurred.

5. Procedure for Establishing the Deferral

The AGO, in its brief, argues that establishment of the ARO is unlawful on several grounds. The AGO argues that the 2015-2017 CCR remediation costs accounted for in the ARO if recovered through rates constitute retroactive ratemaking. The AGO argues that the deferral should not be permitted because DEC failed to obtain prior approval. The AGO argues that deferral of the CCR remediation costs does not meet the test established by the Commission because DEC has not shown that its earnings would have been sufficiently harmed when the ARO was established.

As to the assertion of retroactive ratemaking, the fundamental purpose of creating a deferral is to recognize that the costs were not being recovered in rates when incurred. Moreover, the test period in this case is the 12 months ending December 31, 2016 adjusted for known and measurable charges through December 31, 2017. Consequently, many of the costs are within the test period as adjusted. As to the 2015 costs, the Commission determines they along with subsequently incurred costs have been properly deferred for recovery in this case, were extraordinary when incurred, and were not being recovered in rates in effect at the time incurred. DEC notified the Commission of its decision to establish the ARO in December 2015 and sought permission to defer in December 2016. The AGO commented on the DEC request and did not object to the timing of the request.

The Commission customarily requires contemporaneous approval of deferral accounting for extraordinary expenditures incurred between general rate cases. The Commission prefers this procedure over efforts to recover pre-test year costs recovery in the general rate case where no contemporaneous approval had been sought. This is not a case where DEC failed to seek contemporaneous approval. DEC sought deferral in 2016 after giving earlier notification in 2015. It was in 2016 that the Company had information permitting a quantification of the costs at issue. Just as a utility cannot request prior approval of extraordinary storm damage costs before the storm occurs, no requirement exists of pre-event approval of CCR costs such as these - only reasonably contemporaneous approval, and the Commission has waived even this requirement in the past. See Order Granting General Rate Increase, (Dec. 21, 2012), Docket No. E-22 Sub 479, addressing DNCP's request for deferral of costs of the Bear Garden generating plant. Significantly, any AGO complaint as to timing of the deferral request should have been raised at the time DEC sought approval of the deferral. The AGO made no such complaint.

Similarly the AGO's argument that the deferral should be disallowed because DEC's earnings in 2015 and 2016 were such that deferral was unjustified should have been made at the time the deferral was sought. Moreover, the AGO's untimely evidence to support its theory of lack of economic harm to justify deferral is deficient. The AGO has referred to surveillance reports showing what DEC was earning in 2015 and 2016. These are returns that do not reflect the CCR remediation costs. DEC's December 21, 2015 notification of ARO accounting and its surveillance reports expressly state that the ARO costs are not reflected. Without showing what the returns would have been without deferral, the surveillance report returns tell little about the financial justification for the deferral. Moreover, 2016 is a test year. Financial data fully adjusted after general rate case changes should be used if looking backward at what DEC's earnings were in 2016. The Commission determines that the CCR remediation in the ARO were properly deferred and that the costs so deferred are appropriately amortized over five years and that the unamortized portion is eligible for a return.

6. The Public Staff's Specific Cost Disallowance Proposals

The Commission must undertake a detailed analysis before any costs can be disallowed on the basis of findings of imprudence. 1988 DEP Rate Order, p. 15. The Public Staff undertook such an analysis of the Company's coal ash costs, and based on that analysis presented three discrete and specific proposed sets of disallowances. Two were presented through witness Junis: first, $2,109,406 of legal expenses associated with the defense of litigation matters regarding alleged environmental violations and, second, $2,352,429 reflecting groundwater extraction and treatment costs that witness Junis asserted exceed what CAMA would have required absent alleged environmental violations. Finally, Public Staff witnesses Garrett and Moore recommended a disallowance totaling $97,698,274 relating to the cost of the Company's compliance activities at Buck, Dan River, Riverbend, and W.S. Lee, on the grounds that those activities were more costly than other reasonable alternatives.

a. Junis: Alleged Environmental "Violations"

The Public Staff, through witness Junis, asserts that disallowance of the Company's litigation expense and groundwater costs is justified because these costs flow from "violations" of the law. Tr. Vol. 26, pp. 728-34. For the reasons discussed below, the Commission based on its assessment of the evidence and in the exercise of its discretion determines not to authorize the Public Staff's proposed disallowances of legal expense and groundwater extraction and treatment costs. The evidence does not support a finding that DEC violated the law (with the exception of the federal plea agreement, the costs related to which are not at issue here), nor does it support a finding of imprudence with respect to these costs.

i. Junis: Legal Expenses

Witness Junis cites the Glendale Water case (State ex rel. Utils. Comm'n v. Public Staff, 317 N.C. 26, 343 S.E.2d 898 (1986)) for the proposition that the legal expense should be excluded. In that case, the North Carolina Supreme Court held that legal expense associated with a penalty proceeding in which the utility had been found to have violated the law should be excluded. Witness Junis suggests that the same rationale would apply to his exclusion of the Company's litigation expense related to what he terms DEC's failure to comply with environmental laws and regulations. He claims that "compelling evidence" of such violations is shown by the SOCs and DEQ reports of exceedances. Tr. Vol. 26, pp. 728-29.

The distinction between this case and Glendale Water is that, with the exception of the federal plea agreement with respect to the Dan River spill and Riverbend (for which the Company is not seeking to recover any costs of penalties and fines), there is no finding in the other litigation brought against the Company, or admission by the Company in that litigation, that any "violation" actually occurred. No Intervenor introduced evidence in this case that any "violation" actually occurred. Witness Junis' testimony that the Company's legal expenses for state litigation of coal ash complaints resulted from "violations" is based on the DEQ reports of groundwater exceedances and the fact that DEC sought SOCs to address seeps at the Allen, Marshall, and Rogers (Cliffside) stations, both of which Junis interprets as "compelling evidence of DEC's violations." Tr. Vol. 26, pp. 730-31.

The Commission determines that the facts of this case are distinguishable from Glendale Water. Litigants settle disputed matters frequently for many reasons that are unrelated to the settling parties' underlying view of the merits of the dispute. In this case, for example, the Company and the Public Staff have entered into a Partial Settlement which includes a rate of return on equity of 9.9% (versus the Public Staff's recommendation of 9.1%), and a capital structure of 52% equity and 48% debt (versus the Public Staff's recommendation of 50/50). This settlement, which the Commission has approved, therefore results in millions of dollars paid by customers over and above the Public Staff's pre-settlement position, but that does not mean that the Public Staff somehow ceased to believe in that pre-settlement position. It means that the Public Staff, on balance, determines that its constituency (the using and consuming public) is better off with the Partial Settlement than without, despite the fact that the rate of return on equity and capital structure provisions of the settlement will cause increased rates. Likewise, an SOC is a regulatory mechanism intended to provide clarity and certainty with respect to scope and schedule for compliance-related activities given a change in circumstances, such as a change in requirements or in operations. The Company's willingness to enter into an SOC, therefore, is not premised upon an underlying admission of culpability. Furthermore, as explained by witness Wells, a DEQ report of an exceedance does not equate to a violation of environmental law or regulation.

Witness Junis has attempted to expand the applicability of Glendale Water by applying its holding beyond a litigated finding of liability to include (1) resolutions of complaints that do not involve any finding of liability and (2) pending legal claims of environmental violations, where there is "compelling evidence of environmental violations." Tr. Vol. 26, pp. 729-30. The Commission disagrees with the Public Staff position. Glendale Water applies where there is a finding of liability and the Commission declines to extend its holding further. In addition, the Commission does not find DEQ exceedance reports or SOCs to constitute compelling evidence of environmental violations.

The Commission determines, as it did in the 2018 DEP Rate Order, that entering into a settlement does not equate to an admission of guilt or wrongdoing. 2018 DEP Rate Order, p. 180. Conflating the existence of a settlement agreement or an SOC with an admission or other proof of guilt or wrongdoing is inconsistent with both the law and public policy of North Carolina. The North Carolina Rules of Evidence, for example, prohibit parties from using the existence of a settlement as evidence of liability.[73] Likewise, in

[73] N.C. R. Evid. 408 ("Evidence of (1) furnishing or offering or promising to furnish, or (2) accepting or offering or promising to accept, a valuable consideration in compromising or attempting to compromise a claim which was disputed as to either validity or amount, is not admissible to prove liability for or invalidity of the claim or its amount. Evidence of conduct or evidence of statements made in compromise negotiations is likewise not admissible.").

other matters before the Commission, the Public Staff has defended the regulatory policy of encouraging reasonable and prudent settlements. In 2016, NC WARN filed a Petition for Rulemaking seeking to require settlements between the Public Staff and utilities to be made open to the public. Tr. Vol. 12, p. 156-34; see also Order Declining to Adopt Proposed Settlement Rules, Docket No. M-100, Sub 145 (Mar. 1, 2017) (Settlements Order). The Public Staff opposed NC WARN's petition, arguing that public policy favors settlements:

> [T]he Public Staff submits that settlements promote the informal exchange of ideas and information among the parties, the elimination of insignificant or noncontroversial issues ahead of an evidentiary hearing, informed decision making and the efficient administration of justice, especially in the complex matters that are typically before the Commission. Moreover, settlements result in savings to consumers by reducing litigation expenses that would otherwise be recoverable by utilities as a component of the cost of providing utility service.

Tr. Vol. 12, p. 156-35. See also Settlements Order, p. 3.

Further, in its opposition to NC WARN's petition, the Public Staff cited to North Carolina case law "touting the benefits of settlements" in business litigation. Tr. Vol. 12, p. 156-35. See also Settlements Order, p. 3 (citing Knight Pub. Co., Inc. v. Chase Manhattan Bank, N.A., 131 N.C. App. 257, 262, 506 S.E.2d 728, 731 (1998) (Knight)). The Public Staff relied on the principle articulated in Knight that North Carolina "law favors the avoidance of litigation," and a compromise made in good faith "will be sustained as not only based upon sufficient consideration but upon the highest consideration of public policy as well." Tr. Vol. 12, p. 156-35 (quoting Knight, 131 N.C. App. at 262, 506 S.E.2d at 731 (emphasis added) (internal quotations omitted)). As in the 2018 DEP Rate Order, the Commission again determines not to approve a disincentive to settle pending or future lawsuits. 2018 DEP Rate Order, p. 180. The Commission therefore rejects the Public Staff's proposed disallowance of the Company's legal.

ii. Junis: Groundwater Treatment Costs

Similar considerations apply to the groundwater extraction and treatment costs witness Junis seeks to disallow, which he characterizes as costs to remedy environmental violations that exceed what CAMA would have required absent such violations. He cites as examples of such costs those resulting from (1) the DEQ Settlement Agreement (also referred to as the Sutton Settlement), which Junis contends result in costs greater than would have been necessary to pay for CAMA compliance without violations, and (2) resolutions of lawsuits alleging environmental violations where the outcome involves remedial action that costs more than the risk classification warrants, and "compelling evidence" shows the outcome resulted from environmental violations. Tr. Vol. 26, pp. 731-32. Witness Junis applies this theory of disallowance to include the Company's expenditures for groundwater extraction and treatment at Belews Creek, made pursuant to the September 2015 Sutton Settlement between DEQ, DEC, and DEP. See Junis Exhibit 29, Official Exhibits Vol. 26 (DEQ Settlement Agreement). He also applies this theory to include the Company's expenditures for selenium removal equipment at the Riverbend plant. Tr. Vol. 26, pp. 733-34.

Consistent with the 2018 DEP Rate Order, the Commission again declines to find that the DEQ Settlement Agreement evidences violation of environmental obligations. The DEQ Settlement Agreement references in its recitals a DEQ "Policy for Compliance Evaluations" promulgated in 2011, and it appears from the recitals and their description of that Policy that there was a very serious question as to whether any violation of the State's groundwater standards had occurred. See DEQ Settlement Agreement, at 3, 4-5. The recitals also indicate, with the passage of CAMA, that the Company would be required to close its coal ash basins, and that CAMA "dictate[d], in detail a procedure for assessing, monitoring and where appropriate remediating groundwater quality in areas around coal ash impoundments in North Carolina …." Id. at 3-4. Further, in the recitals the DEQ acknowledged that the CAMA requirements were "designed to address, and will address, the assessment and corrective action" associated with alleged groundwater contamination. Because CAMA would require the Company to implement certain actions, the Commission determines as it did in the 2018 DEP Rate Order (see 2018 DEP Rate Order, p. 181) that it was reasonable for the parties to settle irrespective of whether the Company had committed violations of 2L Standards. Had the Company continued to litigate the matter in this circumstance, its actions may have been deemed by the Public Staff and this Commission to be imprudent, with a disallowance of the legal costs incurred in connection with continued litigation.

The Commission finds the testimony of Company witnesses Wells and Kerin to be instructive with respect to the Public Staff's proposed disallowance of groundwater treatment costs, and entitled to substantial weight. Witness Wells' testimony demonstrates that DEC has in most instances adequately managed its coal ash and that the Company's management and appropriate responses to seeps and groundwater issues do not equate to environmental violations. Witness Kerin's testimony demonstrates that costs related to groundwater extraction and treatment at Belews Creek and its purchase of wastewater treatment equipment at Riverbend were reasonable and prudent and are recoverable.

Witness Wells testified that exceedances of groundwater standards and the existence of seeps in the vicinity of the Company's ash basins do not indicate mismanagement or poor compliance programs. He explained that the existence of groundwater exceedances at or beyond the compliance boundaries at DEC sites is rather a function of where these sites are on the timeline of groundwater assessment and corrective action under modern laws that have changed the way unlined basins are viewed. He testified further that the Company's decision to use unlined basins to treat ash transport water was reasonable and consistent with the approach consistently employed across the power industry at the time that the basins were built, and noted that each DEC site had been properly and legally operating an unlined basin for at least a decade before the adoption of any regulatory requirements related to groundwater corrective action. He stated that as requirements changed over time, DEC has taken action required by DEQ's groundwater rules, and later by CAMA and the federal CCR Rule, to address groundwater impacts as they have been identified. As he noted, witness Junis did not contend that either DEC or the state of North Carolina was an outlier by using unlined basins during this timeframe, and no such contention could reasonably be made given well-published facts about coal power generation practices at that time. Tr. Vol. 24, pp. 227-29, 233, 236, 258.

Witness Wells adequately rebutted the Public Staff's suggestion that DEC only engaged in comprehensive groundwater monitoring and remediation when forced to do so by CAMA and other developments. He testified that the Company began monitoring groundwater at Allen in 1978, Belews Creek and Marshall in 1989, Dan River and W.S. Lee Steam Stations in 1993, and the remaining sites in or around 2006. He noted that, in 2011, DEQ prescribed a process to be undertaken by DEQ and utilities upon the identification of a groundwater exceedance near a coal ash pond, which included performance of an assessment to determine the cause of the exceedance and, as necessary, develop a Corrective Action Plan consistent with North Carolina groundwater rules. He stated that under that process, only after a utility failed to undertake corrective action when directed to do so would DEQ consider pursuing enforcement. He noted that, in contravention of witness Junis' testimony, all of this activity predates the threat of litigation by environmental groups, the DEQ enforcement suit, the Dan River spill, and CAMA. He also testified that, as witness Junis' testimony and exhibits demonstrate, DEC has always promptly responded to any concerns raised by the relevant regulatory entities and where necessary, implemented appropriate corrective action steps to remedy any issue. He stated that the Company has proactively sought consent orders and written agreements to ensure alignment with the regulatory agency as to appropriate scope and timing of additional investigation and corrective action. Tr. Vol. 24, pp. 230-31, 234-36, 259-60.

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 an 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.

Witness Wells contrasted this process with groundwater standards, under which an exceedance does not immediately result in an NOV and escalating penalty. Instead, he explained the owner/operator must report the exceedance and work with the DEQ to determine whether it was due to permitted activity, assess the extent of the exceedance, and undertake corrective action. 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 an additional assessment prior to corrective action is conducted. He testified that the 2L rules' corrective action provisions are deliberately designed around the idea that older facilities, built before liners were a regulatory obligation, were likely to have associated groundwater impacts, that such impacts were not the result of regulatory noncompliance, and that they should be addressed in a measured process. He concluded that compliance with this process is not mismanagement and should not be held against DEC with respect to cost recovery. Tr. Vol. 24, pp. 245-46. The Commission agrees.

The Commission is further persuaded by witness Wells' testimony that witness Junis' characterization of groundwater violations under the 2L rules ignores the iterative nature of comprehensive site assessment. He noted that measuring exceedances at different locations in a plume around an activity may result in multiple exceedances of groundwater standards, but that does not result in multiple violations of the 2L rule's prohibition. He explained that this distinction is important for evaluating the claim that the number of exceedances indicates a "breadth of environmental violations." It would be more accurate to say, he explained, that, at seven sites, DEC has lawfully operated ash basins that, after decades of use, resulted in exceedances of groundwater standards at those sites. He pointed out how Duke Energy's coal ash basins are some of the most studied sites in North Carolina, with more than 1,400 groundwater monitoring wells, and that the number of exceedances presented by witness Junis signifies therefore the thoroughness of the evaluation rather than a number of groundwater violations. Tr. Vol. 24, pp. 238-41, 260-61. The Commission notes in particular witness Wells' testimony at the hearing that the iterative (and difficult) nature of monitoring groundwater impacts is illustrated by the fact that two wells located a short distance from each other could present very different conditions, including different naturally occurring constituents. Tr. Vol. 26, pp. 91-93.

Witness Wells also persuasively argued that the groundwater extraction and treatment costs that witness Junis recommended for disallowance relate to activity that DEC agreed to undertake pursuant to the DEQ Settlement Agreement to accelerate, but that would have been required in the normal course as part of the groundwater correct action under the CCR Rule and CAMA. Tr. Vol. 24, p. 241. Although CAMA borrows heavily from the 2L Rules, including by incorporating the substance of its corrective action requirements, one key difference between the two laws is that CAMA's groundwater assessment and corrective action provisions are triggered by exceedances – not violations – of the 2L groundwater standards.[74] In other words, unlike the 2L Rules, CAMA requires utilities to perform groundwater assessment and corrective action for all identified exceedances of the 2L groundwater standards regardless of whether the exceedance amounts to a violation of the applicable groundwater standard.

The Commission is also persuaded by the evidence presented by Company witness Kerin in response to the Public Staff's position, which shows that the groundwater treatment wells installed at Belews Creek would have been installed even without the DEQ Settlement Agreement, because while the time frame for that installation was moved

[74] Id.; see also N.C. Gen. Stat. § 130A-309.211. When preparing a corrective action plan, CAMA does not require the utility to describe any 2L violation and instead required only a "description of all exceedances of the groundwater quality standards, including any exceedances that the owner asserts are the result of natural background conditions." N.C. Gen. Stat. § 130A-309.211(b)(1)a (emphasis added).

up pursuant to the Agreement, the Company would have installed the wells in order to comply with CAMA even absent the Agreement. Tr. Vol. 24, p. 117.

Based on the credible and persuasive testimony of the Company's witnesses, the Commission determines, with exceptions addressed below, that there is insufficient evidence that DEC would have had to engage in any groundwater extraction and treatment activities absent the obligations imposed upon it by CAMA and/or the CCR Rule. Witness Wells' testimony in particular shows that the assertion that DEC's "violations" resulted in the DEQ Settlement Agreement and in groundwater extraction and treatment costs that would not otherwise have been incurred is incorrect and not supported by the evidence.

The Commission determines that Witness Kerin also successfully rebutted witness Junis' position that the cost of equipment to remove selenium at Riverbend should be disallowed. He explained that it was imperative for the Company to have a system to appropriately treat the site wastewater and to meet future permit selenium limits. He also noted that while this system is important for those reasons, because it is also expensive to operate, the Company will only use it when other physical and chemical extraction methods are insufficient. He emphasized the prudency of having this system in place should it be needed, in order to avoid the need to cease ash removal operations if selenium levels increased and no bioreactor was on site. He noted that such a delay would cost the Company millions of dollars of delay charges. Tr. Vol. 24, pp. 90, 117-19, 132. The Commission agrees that it was reasonable and prudent for the Company to purchase the bioreactor system to mitigate against potential violations of permit limits and declines to accept witness Junis' recommended disallowance of these costs.

No party disputes the reasonableness of the amount of groundwater assessment and treatment costs the Company seeks to recover in rates. The dispute relates instead to the fact that the groundwater assessment and treatment costs were incurred pursuant to a settlement with DEQ and in response to DEQ reports. The testimony of witnesses Kerin and Wells demonstrates that these costs – amounting to $2,352,429 – were reasonably and prudently incurred to comply with the Company's obligations under CAMA and the CCR Rule. The Commission determines that they therefore are recoverable in rates, as are the $2,109,406 in legal fees that witness Junis also proposed excluding.

The AGO, Sierra Club, and other Intervenors make similar arguments to the Public Staff that DEC has failed to keep pace with industry standards and should therefore not be allowed to recover current environmental compliance costs in rates. As in the DEP case, these Intervenors argue that the Company should have done more, in contradiction to other witnesses that DEC should have done less, than just comply with the current environmental regulations at the time.

As an initial matter, based upon the evidence presented in this case, with the exception of the federal criminal case to which DEC pled guilty, the Company has not been found liable for violations of the law. As stated above, the Commission will not use settlement agreements to find liability. The AGO witness asserts that the Commission should consider all of the seeps located at DEC's ash basin sites and deny recovery of CCR costs except – as clarified at the hearing – those which are incurred to comply with the CCR Rule. However, as stated in the criminal case that covered engineered seeps, DEQ and DEC have been in long-standing negotiations as to whether seeps are a violation of the law and since 2014, whether seeps should be covered by the NPDES permit. AG-Kerin Direct Cross Examination Exhibit 6, pp. 78, 95; AG-Kerin Direct Cross Examination Exhibit 5, p. 44. According to statements made in the criminal case, DEQ has currently not made a determination on this issue. AG-Kerin Direct Cross Examination Exhibit 5, p. 44.

In addition, the Commission finds the testimony of Company witness Kerin informative as to Intervenors' claims. Witness Kerin explained that the securities filings cited by AGO witness Wittliff simply notified the SEC of potentially significant coal ash costs that Duke Energy anticipated at that time, and potential new regulatory contingencies to which it could become subject; they were not intended to analyze the Company's coal ash management practices and do not support any claim that such practices were out of step with industry, much less that DEC was aware of any such inconsistency. Witness Kerin also rebutted the AGO's assertion that the Company should have built new lined impoundments rather than expand existing unlined impoundments, citing the significant expense that new lined impoundments would entail, while not eliminating the obligation to maintain existing unlined impoundments. He pointed out that such action would have put the Company at risk of disallowance of costs. He recalled witness Wittliff's testimony in the DEP proceeding that utilities continued to use unlined wet ash impoundments because the law continued to allow them to do so, and noted the inconsistency between admitting that such a practice was legal and asserting that it was also imprudent. Witness Kerin also enumerated the ways in which the Company has practiced dam safety and explained that the five-year dam safety inspections demonstrate careful monitoring of issues as well as a lack of any major issue threatening dam integrity. Tr. Vol. 24, pp. 119-24. For many of the same reasons, witness Kerin demonstrated the inaccuracy of Sierra Club witness Quarles' assertions regarding the consistency of the Company's coal ash management practices with industry standards and the costs of lined landfills as opposed to surface impoundments. Tr. Vol. 24, p. 91.

The limitations of the Intervenors' and the Public Staff's approach is the fact that the kinds of actions they appear to have favored – such as lining ash ponds when others in the industry were not lining them, or creating dry ash basins when the Company's industry peers were sluicing coal ash into wet basin impoundments, would (a) have increased costs that 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. These parties advance inconsistent positions. They fault the Company for not undertaking steps that others were not, but at the same time disavow any responsibility of paying for that which they – in 20/20 hindsight – wish the Company had undertaken. As noted at the hearing during questioning of Company witness Wells, these parties criticize the Company's coal ash management practices dating back decades, yet took no actions themselves to address coal ash until within the past five years. For all of these reasons and based on the evidence presented, the Commission is not persuaded, with exceptions noted below and later in this the order, 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.

The AGO and the Sierra Club further assert that all of the coal ash closure costs are the result of unlawful discharges and are not recoverable pursuant to N.C. Gen. Stat. § 62-133.13. The Commission rejects the AGO and Sierra Club's reading of N.C. Gen. Stat. § 133.13. The costs being incurred are not resulting from an unlawful discharge as defined by the statute, which is a discharge that results in a violation of State or federal surface water quality standards. Rather, DEC is incurring the costs to comply with the federal CCR rule and CAMA.

Lastly, with respect to the bottled water expense DEC is seeking cost recovery of, although no party requested a specific disallowance for the cost of bottled water, the Commission finds that DEC shall remove from its request for recovery any costs for bottled water.[75]

b. Garrett and Moore: Overview

The Public Staff, through witnesses Garrett and Moore, asserts that the Company acted imprudently and unreasonably with respect to the management of CCRs from the Buck, Dan River, Riverbend, and W.S. Lee Plants, and contends that the Company should have selected different management approaches, thereby saving costs. The Public Staff recommends that a $10,612,592 disallowance be applied with regard to Buck Plant ash (Tr. Vol. 21, p. 61), a $59,320,890 disallowance be applied with regard to the Dan River Plant ash (Tr. Vol. 21, p. 67), a $489,600 disallowance be applied to Riverbend Plant ash (Tr. Vol. 21, p. 74), and that a $27,275,192 disallowance be applied with regard to W.S. Lee ash (Tr. Vol. 21, pp. 34-34), for a total recommended disallowance of $97,698,274.

The Commission determines not to accept this discrete disallowance, based upon the testimony of Company witness Kerin, which the Commission credits and to which the Commission attaches substantial weight. In the 1988 DEP Rate Order, this Commission stressed the importance of carefully examining the Company's explanations of the decisions it made, as of the time they were made, and emphasized the credibility of the decision-makers, particularly in juxtaposition to after-the-fact analyses presented by Intervenor-retained consultants. See, e.g., 1988 DEP Rate Order, p. 29. The Commission does not question the bona fides or expertise of Garrett and Moore. The Commission is persuaded, however, by witness Kerin's testimony that Garrett and Moore missed or overlooked pertinent facts and real world conditions in their recommendations, and that

[75] The total amount spent on bottled water through the end of August 2017 is $1,606,185. These costs include the bottled water itself, the delivery company and personnel associated with the delivery, and the consulting firm that is managing the overall bottled water delivery program for Duke Energy. Tr. Vol. 14, pp. 220-21.

their discrete disallowances are therefore unwarranted. Witness Kerin's testimony regarding the Company's decisions is entitled to substantial weight – more weight than after the fact evaluations from Garrett and Moore. Witnesses Garrett and Moore's recommended disallowances were challenged at the hearing through cross-examination. These witnesses were unable effectively to support their positions while on the witness stand. The Commission determines their recommendations deficient on the basis of a lack of credibility. In this regard, the Commission is not persuaded to discount witness Kerin's testimony by witness Wittliff's challenges to witness Kerin's expertise. As concluded in the 2018 DEP Rate Order, witness Kerin has "lived" this project since its inception (2018 DEP Rate Order, p. 187), and demonstrated competent understanding of the subject in pre-filed testimony and at the hearing. Witness Witliff's testimony from the witness stand likewise suffered from a lack of credibility.

i. Moore: Location of On-Site Landfill at Dan River

Witness Moore asserted that, while he agreed with DEC's decision to construct an on-site landfill at Dan River, he disagreed with the Company's chosen location for the onsite landfill. Tr. Vol. 21, pp. 90-91. Instead of locating the landfill within the footprint of the Ash Fill areas – which required first excavating and transporting off-site ash from those area – witness Moore contended that DEC should have considered locating the landfill along the western property boundary of the site, Id. at 91-92, even though he conceded that the CAMA moratorium prohibited construction of new or expanded CCR landfills located wholly or partly on top of the Primary Ash Basin, Secondary Ash Basin, and the Ash Fill 1 and 2 areas. Tr. Vol. 24, p. 94. Witness Kerin's rebuttal testimony demonstrates that witness Moore's proposal was not feasible in the time frames available to the Company, and in likelihood impossible from an engineering perspective.

Witness Moore illustrated his proposed landfill site location with a chalk-line, ovaloid drawn on top of an existing jurisdiction water designation map for the Dan River Plant. Tr. Vol. 21, p. 44; Moore Direct Exhibit 4. This drawing is the totality of the engineering work papers and documentation offered in support of his proposal in his direct testimony. Tr. Vol. 21, p. 92. To agree with witness Moore's recommended disallowance, the Commission would have to conclude that DEC should and could have constructed his proposed landfill in compliance with North Carolina law. The Commission cannot reach that conclusion based on the dearth of supporting documentation from witness Moore regarding his proposed landfill, as well as the volume of evidence presented by witness Kerin in opposition to witness Moore's suggestion. An alternative proposed action must have been feasible in order to be a valid alternative. 1988 DEP Rate Order, p. 15.

Witness Moore admitted that he did not conduct a site suitability study for his proposed landfill location, nor did he conduct a hydrogeologic study of the conditions at the western portion of the Dan River Plant property. Both studies are required under North Carolina law before a landfill can be permitted or constructed. See 15A N.C. Admin. Code 13B §§ .0503-.0504. He did not analyze soil borings of that area of the property, did not visit the portion of the property where he proposed siting the landfill, despite having the opportunity to do so when he made a site visit to the property, and did not make an attempt, at the time he submitted his direct testimony, to calculate the height of his proposed landfill. Tr. Vol. 21, pp. 92-93. Witness Moore only did this after witness Kerin filed his testimony. Tr. Vol. 22, p. 26. His testimony and workpapers, or lack thereof, would not satisfy North Carolina's landfill permit application requirements, let alone justify construction of his landfill.

The Commission concludes that DEC engineers reached the reasonable and prudent decision to reject the western portion of the property as a feasible location for an onsite landfill. As witness Kerin discussed in his rebuttal testimony, there are many engineering and other obstacles to the construction of an onsite landfill along that portion of the property.

First, construction of witness Moore's proposed landfill would have required excavation of an LCID Landfill containing asbestos. The fact that the LCID Landfill contained asbestos was not known to witness Moore when he filed his testimony, but could have been discovered had he pulled the publicly available permit for that landfill. Tr. Vol. 21, pp. 97-99. In his direct testimony, witness Moore suggested that the LCID Landfill could have been excavated and transported to the Rockingham County Landfill. As the Rockingham County Landfill no longer accepts asbestos, witness Moore conceded that his proposal with regard to the LCID Landfill was no longer possible. Tr. Vol. 21, p. 99. Even if there was a location that could accept the materials containing asbestos in the LCID Landfill, the Commission is persuaded by witness Kerin's testimony that it was prudent for the Company to avoid unnecessarily exposing workers or neighbors to asbestos by locating the onsite landfill in a location that would have required excavation of the asbestos. Tr. Vol. 24, pp. 97-98.

Witness Moore's proposal was also infeasible in that it would have significant wetland and stream impacts as compared to the minimal impacts to streams and wetlands posed by the Company's chosen onsite landfill location. Witness Moore's testimony gave too little attention to stream and wetland impacts, suggesting that mitigation of on-site streams is not uncommon to allow for construction of landfills. Tr. Vol. 21, p. 65. However, witness Moore made no attempt in his testimony to identify the stream and wetland impacts, to prepare a permitting timeline for those impacts, or to analyze the likelihood that those impacts could be permitted. As witness Kerin stated in his rebuttal testimony, and witness Moore acknowledged during live testimony, the U.S. Army Corps of Engineers (Army Corps) will conduct an alternatives analysis demonstrating the practicality of other options that would not impact streams or wetlands, and that permit applicants are required to avoid and minimize aquatic resource impacts to the maximum extent practicable. Tr. Vol. 21, pp. 104-05; DEC-Garrett and Moore Cross Ex. 1, Tab 6; Tr. Vol. 24, pp. 98-100. As compared to witness Moore's proposal, the Company's selected landfill location avoided and minimized impacts to onsite streams and wetlands. Therefore, permitting witness Moore's selected location for stream and wetland impacts would have been challenging based on the Army Corps' alternative analysis criteria. In order to meet CAMA's deadlines, it was reasonable and prudent for DEC to avoid the permitting uncertainty created by witness Moore's proposal by avoiding impacts altogether.

Witness Moore's proposal raises additional permitting uncertainties. Witness Kerin testified that the stream combination on the western and southern sides of witness Moore's proposed landfill would have required the Company to obtain a new construction permit to construct an industrial NPDES outfall through the service water pond, and that both the permit and the outfall would have required substantial time to obtain and construct. Both the new permit and outfall would have to be in place before construction on the landfill could begin, potentially jeopardizing compliance with CAMA's deadlines. The CAMA deadlines provide the overarching framework by which prudency must be assessed. 2018 DEP Rate Order, p. 185. In addition, witness Kerin noted that the 100-year flood plain in this area intrudes into portions of witness Moore's proposed location, and would present additional permitting challenges and likely not leave sufficient space for required stormwater management features on the site. Tr. Vol. 24, pp. 100-02. Witness Moore did not dispute these conclusions.

The evidence shows that had witness Moore visited the site of his proposed landfill, he would have confronted dramatic elevation changes and other topographical features, such as steep slopes, that would have made his proposed site difficult. Further, had witness Moore conducted a site suitability or hydrogeologic study, he would have discovered that the depth to bedrock on the western portion of the property is fairly shallow, leaving little room for excavation for fill volume, borrowing soil or buffering to groundwater. While witness Moore agreed that a landfill owner should minimize potential impacts to neighbors, wetlands, and dangerous materials as much as possible, (Tr. Vol. 21, p. 108), the above site-specific conditions unique to the western property boundary, which witness Moore did not consider in his analysis, would have resulted in a landfill that was in the neighbors' line of sight and more intrusive than the Company's selected location. Tr. Vol. 24, pp. 100-02.

DEC's decision to minimize impacts to neighboring properties in siting its onsite landfill was consistent with an agreement that the Company would ultimately reach with the City of Eden regarding the Dan River site. As a condition of allowing DEC to construct an onsite landfill, the City of Eden required that the landfill be located near the existing basins, and as remote from residential areas as feasible. Tr. Vol. 21, p. 106; DEC-Garrett and Moore Cross Ex. 1, Tab 7. Witness Moore did not dispute the City of Eden agreement's conditions. Tr. Vol. 21, p. 107-08. The nearest location to the existing basins is within the footprint of the former ash stack, and this is the location DEC chose for the landfill. This choice also minimized impacts to surrounding properties by ensuring that the landfill was located as far as feasibly possible from neighboring properties. In contrast, as witness Moore acknowledged, his selected location was not closest to existing basins or as remote as feasible from residential areas. Id. Therefore, had DEC selected witness Moore's proposed landfill location, Mr. Kerin testified, the City of Eden likely would not have approved the zoning required to construct the landfill in this location. See 15A N.C. Admin. Code 13B § .0504(1)(e) (requiring local government approval for construction of a landfill). Witness Kerin stated that, if witness Moore had considered the

City of Eden agreement, he could not have concluded that his alternative landfill location was reasonable or prudent. Tr. Vol. 24, pp. 95-96. The Commission agrees.

Infeasible options do not support a finding of imprudence. 1988 DEP Rate Order, p. 15. Witness Kerin's testimony demonstrates that the Company's actions and real-time decisions regarding the Dan River site were in fact reasonable and prudent, and the costs were prudently incurred. The Commission therefore rejects the Public Staff's proposed disallowance of these costs.

ii. Moore: Buck as Beneficiation Site

Witness Moore contended that DEC should have chosen Weatherspoon over Buck as a beneficiation site, and recommended disallowance of beneficiation costs of $10,612,592 incurred within the test period at Buck. The Commission rejects witness Moore's discrete recommendation. Witness Kerin's testimony shows that witness Moore's analysis is based on a faulty interpretation of CAMA, and that DEC's selection of Buck was reasonable and prudent because it satisfies market demands and maximizes capital investment in the required beneficiation equipment.

CAMA requires the Company to: (i) identify two sites by January 1, 2017 and an additional site by July 1, 2017; and (ii) "enter into a binding agreement for the <u>installation</u> and <u>operation</u> of an ash beneficiation project at each site capable of annually <u>processing</u> 300,000 tons of ash to specifications appropriate for cementitious products, with all ash processed to be removed from the impoundments located at the sites." N.C. Gen. Stat. § 130A-309-216 (emphasis added). Witness Kerin testified that DEC satisfied CAMA's requirements by identifying Buck, H.F. Lee, and Cape Fear as the three beneficiation sites based on its conclusion that they offered the most feasible alternative and the best economic value to customers while complying with CAMA. Tr. Vol. 24, pp. 93, 105-08, 131.

At each of the three sites, the Company has contracted to install and operate STAR technology units to process the onsite ash. Tr. Vol. 21, p. 112. The Company has also contracted to sell 230,000 tons of ash from Weatherspoon as aggregate in the manufacture of cement. <u>Id.</u> at 59, 116; Tr. Vol. 24, p. 107.

Witness Moore suggests that the Company could have selected Weatherspoon as a beneficiation site if it had only found a buyer for another 70,000 tons of ash from this location to qualify under CAMA. By selecting Buck, witness Moore contended, Duke Energy supplied an additional 300,000 tons per year of CCR material to the concrete industry, in turn reducing the demand for the 70,000 tons per year of CCR material for the same purposes from Weatherspoon for which Duke Energy was unable to find a purchaser. While the Company agrees that reuse of ash at Weatherspoon is appropriate – and the Company is selling Weatherspoon ash for reuse today – it contends that the Weatherspoon ash would not satisfy CAMA. Based on the testimony of witness Kerin, the Commission agrees.

Contrary to Public Staff witness Moore's suggestions otherwise (Tr. Vol. 21, pp. 111-12), the Commission concludes that the most reasonable reading of N.C. Gen. Stat. § 130A-309-216 indicates that the General Assembly intended that Duke Energy install and operate technology, such as carbon burn-out plants and STAR technology, to process and transform ash to a usable product rather than use the basic drying and screening methods occurring at Weatherspoon. Tr. Vol. 24, pp. 106-07. It is here where witness Moore's theory becomes problematic.

Witness Moore's testimony suggested that the Company's handling of Weatherspoon ash, which does not involve beneficiation processing or much of any processing beyond excavation, would satisfy the CAMA beneficiation requirement. At the hearing, however, witness Moore admitted that the DEP sites chosen for beneficiation under CAMA – Cape Fear and H.F. Lee – and the DEC site, Buck, have and will use the STAR technology to beneficiate ash, and that the ash being sold from the Company's Weatherspoon site is not being beneficiated with STAR technology. He confirmed that installation of a STAR facility to convert ash for cementitious purposes is a reasonable and prudent method of executing the requirements of CAMA, and that ash from the ponds is run through the STAR unit and burned to lower the carbon content of the ash. The process changes the physical and chemical characteristics of the ash, thereby creating a stronger product that can be used in the ready-mix market. Tr. Vol. 21, pp. 111-13, 115; DEC-Garrett and Moore Cross Ex. 1, Tab 12, p. 6. As witness Moore agreed on cross examination, the Weatherspoon ash and the ash that is beneficiated with such technology, as at Buck, are "apples and oranges." Id. at 117.

Witness Moore did not object to Duke Energy's beneficiation approach at H.F. Lee and Cape Fear. Having concluded that installing STAR units at H.F. Lee and Cape Fear was a reasonable and prudent "method of executing the requirements of CAMA," (Id. at 113), the Commission determines that he cannot creditably argue that Duke Energy could have simply excavated, dried, and sold ash from Weatherspoon and still satisfied CAMA's beneficial reuse requirements. Id. at 112. In other words, witness Moore admitted that STAR units accomplish the following: "the installation and operation of an ash beneficiation project at each site capable of annually processing 300,000 tons of ash to specifications appropriate for cementitious products." N.C. Gen. Stat. § 130A-309-216. His recommended disallowance, however, in this rate case, depends on a reading of CAMA that does not require installation of a STAR unit or similar technology. The Commission determines that the Public Staff position is inconsistent. The Commission concludes that CAMA contemplates the installation of STAR units or other ash processing technology that changes the physical and chemical characteristics of ash to specifications appropriate for cementitious products.

In addition, witness Kerin pointed out that, even after issuing an RFP, Duke Energy has only been able to secure a buyer willing to enter into a long-term contract for 230,000 tons of ash from Weatherspoon, but not the additional 70,000 tons. Tr. Vol. 24, pp. 105-06. Witness Moore made no attempt to identify a potential buyer for the 70,000 tons. Tr. Vol. 21, pp. 118-19. While the Weatherspoon ash is sold under contract to cement manufacturers and is used as raw material or aggregate in the manufacture of cement, the processed ash from Buck is used as a replacement for cement in concrete. Because these are separate products that are used for different purposes, the sale of beneficiated ash from Buck has no impact on the demand for ash from Weatherspoon. Id. at 105-06. The Commission determines that finding a buyer for 70,000 tons of ash from Weatherspoon would not solve the compliance problem witness Moore identifies. Under his proposal, none of the ash would be processed through a STAR Unit or similar technology, and would therefore not meet CAMA's beneficiation requirement.

The Commission also agrees with the Company that, because CAMA requires the installation of a STAR Unit or similar technology, a cost of approximately $181 million, it was reasonable for the Company to consider the amount of ash available at the site and the potential uses for the ash when making a decision to invest in beneficiation at a particular location. Weatherspoon contains only 2.4 million tons of ash, which is approximately one-third the 6.4 million tons at Buck, so the per-ton cost to process ash at Buck is significantly lower than it would be at Weatherspoon. Additionally, Weatherspoon is in a poor geographic location in relation to the major markets for ash used in the cement industry. Because trucking the ash is part of the cost of the sales, Buck's proximity to Charlotte and Greensboro makes it a much better location for beneficiation, and has the highest revenue projection, followed by Cape Fear (Greensboro and Raleigh) and H.F. Lee (eastern North Carolina and Virginia).

Witness Moore's proposal is not feasible as it would not satisfy the Company's statutory requirement to beneficiate ash. Alternative proposed actions must be feasible in order to truly be alternatives. 1988 DEP Rate Order, p. 15. The Commission cannot, therefore, conclude that the Company was unreasonable or imprudent by selecting Buck over Weatherspoon, and by implementing a beneficiation plan at Buck that does satisfy CAMA.

iii. Moore: Riverbend Off-site Transportation Costs

Public Staff Witness Moore took no exception to DEC's overall ash management plan at Riverbend, including its decision to remove CCR material from the ash stack area or the cinder pit, even though those units are not subject to CAMA or CCR. He did object to DEC's decision to transport and dispose of CCR material from the ash stack to the R&B landfill in Homer, Georgia and to the Brickhaven Facility. Witness Moore recommended that the Commission disallow $489,000 as the premium that was paid to dispose of CCR material from the Ash Stack at the R&B Landfill in Homer, Georgia versus the Marshall Station. Tr. Vol. 21, pp. 72-73.

As witness Kerin noted in his testimony, DEC was required to begin excavation of ash from Riverbend within 60 days of receiving its stormwater permit from DEQ. When DEC received that permit in May 2015, Marshall was not available to accept Riverbend ash. Since DEQ issued the permit on May 15, 2015, DEC had until July 15, 2015 to begin excavating Riverbend ash. While the Company was exploring long-term options to receive the Riverbend ash, it was still obligated to meet DEQ's deadline, and thus it was imperative that the Company contract with a company to haul and dispose of the

Riverbend ash on a short turnaround. Waste Management National Services, Inc. (Waste Management) was able to meet that requirement, and began trucking ash from Riverbend on May 21, 2015, and transported the final load on September 18, 2015. While DEC eventually received approval to dispose of Riverbend ash at Marshall, the Commission is persuaded that DEC would not have been able to send ash to Marshall within the time frames required by DEQ. Tr. Vol. 21, pp. 93, 108-10, 131-32.

Witness Moore's recommended disallowance is based on a "perfect world" scenario where DEC could have accurately predicted permitting uncertainties, such as the dates when DEQ was going to issue the stormwater permit for Riverbend or approval for ash disposal at Marshall. The Commission declines to approve disallowances where the Company promptly achieved compliance with DEQ's 60-day excavation requirement. The Commission uses the CAMA deadlines as the framework by which to assess prudency. 2018 DEP Rate Order, p. 185. The Commission concurs with witness Moore that "[t]he lowest cost option may not always be the reasonable or prudent decision. The determination must be made on a case-by-case basis and the specific factors, obligations, site-specific limitations and other factors known by management at the time." Tr. Vol. 21, pp. 89-90. The Commission concludes that the Company acted reasonably and prudently for the Company to begin excavation at Riverbend as soon as practicable in order to ensure compliance with DEQ's requirements. This decision necessitated finding a temporary disposal solution; therefore, the costs associated with that temporary disposal solution are also reasonable and prudent and should not be disallowed.

iv. Garrett: W.S. Lee Off-site Transportation Costs

The Commission is not persuaded by witness Garrett's testimony that a lower cost option at W.S. Lee was feasible. Like witness Moore's recommended onsite landfill at Dan River, witness Garrett's proposal for W.S. Lee may look viable on paper, but when applied to "real world" conditions, it loses its persuasiveness.

As an initial matter, the Commission agrees with the Company and witness Garrett that DEC's overall ash management plan at W.S. Lee, which includes building an onsite landfill to store ash from the Primary and Secondary ash basins, is reasonable and prudent. Tr. Vol. 21, pp. 25-26. The Commission also agrees that some action was necessary to excavate the IAB or Old Ash Fill to mitigate risk associated with the long-term environmental issues, based on the proximity of the IAB to the Saluda River. The Commission declines to accept, however, witness Garrett's conclusion that delaying excavation of those sites for seven years would have been acceptable to South Carolina regulators or would have eliminated the risk to the Saluda River. Tr. Vol. 24, p. 156.

No dispute exists that DEC's decision to excavate the IAB and Old Ash Fill before the onsite landfill was complete eliminated the geotechnical and environmental risks by November 2017. Tr. Vol. 21, p. 28. Under witness Garrett's plan, ash in the IAB and in the Old Ash Fill would have been left in place and not excavated until the on-site landfill in the secondary ash basin was complete in 2022. Tr. Vol. 21, pp. 129, 130-31. Therefore, the ash would have remained in the IAB and Old Ash Fill an additional seven years until

2022 as compared to the excavation plan DEC undertook. Tr. Vol. 21, pp. 127, 131-32. Under the Company's agreement with SCDHEC, which required excavation of the IAB and Old Ash Fill by December 31, 2017, witness Garrett's seven-year delay was not an option. Tr. Vol. 24, p. 151.

Even assuming witness Garrett's plan was technically feasible and would have resolved the stability issues, implementing his plan would have required trading old risks for new risks. See DEC-Garrett and Moore Cross Ex. 1, Tab 20. Witness Garrett acknowledged during live testimony that the report contained at Tab 20 concluded that if the IAB ash was not removed, danger arose of it's flowing into the Saluda River. Tr. Vol. 21, pp. 135-36. He also acknowledged that in certain areas of the IAB that abut the Saluda River, the steep, 1:1 slopes are covered in trees and vegetation. Id. at 137. Witness Garrett also agreed that trees would have to be removed to execute his proposal, but he did not consider in his analysis how the trees would be removed (with heavy equipment or chain saws) or how tree removal might affect slope stability. Id. at 148-49. He also acknowledged that soft, alluvial clays run beneath the IAB and the steep slopes where his proposed work would occur, and that the dam itself is partially constructed from ash and sandy silt that would also have to be excavated. Id. at 138, 141. Witness Garrett conceded that his work proposal as reflected in Garrett Direct Exhibit 3 is "not a design document" nor is it "specific instruction on how to go about that work." Id. at 141. He also acknowledged the limitations of the S&ME report on which he relies, in that it, too, does not explain practically how a slope stability and grading project would be executed. Id. at 141, 146-47.

The Company provided persuasive evidence in the form of witness Kerin's testimony that witness Garrett's proposed grading and stability project would not have been reasonable or prudent. Witness Kerin testified that the equipment necessary to implement witness Garrett's proposal could not have safely traversed the dike on the downslope of the IAB. Moving the heavy equipment to the downstream/river side of the downslope to excavate silt, ash, sand and trees would have created undue risk to bank stability, worker safety, and risk of an ash release into the Saluda River. Witness Garrett's proposed project would have unnecessarily put worker and environmental safety at risk, and the delay would have been unacceptable to DEC and to the SCDHEC. These new risks were understandably unacceptable to the Company. Tr. Vol. 24, pp. 112-14, 132.

The Commission cannot conclude that witness Garrett's proposal was the more reasonable and prudent option because the Public Staff cannot show, from an engineering perspective, how the work would be practically and safely executed. The Public Staff only presented a concept. To take witness Garrett's plan from concept to reality would require engineering and design plans with specific instructions on how the work would be conducted. Tr. Vol. 21, p. 141. The Public Staff, although armed with an engineering expert, failed to present any such plans. On the other hand, Company witness Kerin credibly provided evidence of the real-world flaws with witness Garrett's concept, from both timing and engineering perspectives.

The Commission concludes that it was reasonable and prudent for Duke Energy to immediately excavate the IAB and Old Ash Fill, in compliance with its agreement with SCDHEC. Duke Energy was able to eliminate existing risks without creating new risks. The Commission declines to second-guess the Company's judgment in that regard. Therefore, because no onsite landfill was available for the disposal of the IAB and Old Ash Fill materials at the time they were excavated, it was also reasonable and prudent for the Company to utilize the R&B landfill in Homer, Georgia for disposal of those materials, and the costs associated with that effort should not be disallowed.

Finally, based on witness Kerin's testimony the Commission agrees that the Company's plan to mitigate future risk of operating two ash management structures, which would be the result if it did not excavate the Structural Fill Area at W.S. Lee in the future, is reasonable and prudent, even though witness Garrett did not suggest any disallowances with respect to this plan. Witness Kerin stated that, in order to resolve the concerns of SCDHEC and environmental groups, the Company agreed to mitigate future risk of operating two ash management structures by managing all ash at W.S. Lee through a single management structure – the landfill – as opposed to taking a piecemeal approach as suggested by witness Garrett. He stated that if the Company was later required to excavate the Structural Fill area after the landfill project was completed, it would incur greater costs than it will incur by managing the ash while the landfill project is ongoing, and that the decision to excavate this area now is reasonable and prudent approach to mitigating against potential future ash related liability and to reduce future costs for the site. Tr. Vol. 24, pp. 93, 116.

7. <u>Conclusion with respect to January 1, 2015 – December 31, 2017 Costs</u>

The Commission finds that the costs are known and measurable, were reasonably and prudently incurred, and to the extent capital in nature are used and useful in the provision of service to customers. The Commission determines the costs were properly deferred. As such, with the exception noted below, they are recoverable from customers. The issue that remains is the amortization period over which this recovery is to be made.

The Commission deems the Company's proposal, which submits that the amortization period should be five years, to be reasonable and appropriate. The Public Staff, in its 51/49 "equitable sharing" proposal, suggests a period of 25 years (with no return), but its suggestion is tied to (indeed, mathematically required by) the sharing arrangement. As discussed more fully above, the Commission determines that the Public Staff's sharing proposal is from the Commission's perspective arbitrary and unfairly punitive and therefore unacceptable. Thus, a 25-year, no return amortization period is not approved. The five-year period suggested by the Company is identical to the period over which the Commission approved in the 2018 DEP Rate Case, as well as the period over which Dominion North Carolina Power's already-incurred coal ash basin closure costs were amortized in the 2016 DNCP Rate Case (Docket No. E-22, Sub 532). Further, inasmuch as the Company appropriately applied ARO accounting and this Commission's deferral orders issued in Docket No. E-7, Sub 723 to these costs, the Company is eligible to earn a return.

In summary, with the exception noted below, DEC has shown by the greater weight of the evidence that its coal ash basin closure costs actually incurred over the period from January 1, 2015 through December 31, 2017 are (a) known and measurable, (b) reasonable and prudent, and (c) where capital in nature used and useful, and, as such, those costs are recoverable in rates. DEC has further shown that its proposal that these costs be amortized over five years, with a modified return on the unamortized balance, is reasonable. The Commission encourages the selection of minority and women-owned businesses, where appropriate, when contracting for future services associated with compliance with CAMA and the CCR Rule.

8. The Commission's Cost of Service Penalty

The costs DEC has incurred through the end of the test year as adjusted in coal ash remediation tasks have been substantial, and the Company will continue on an annual basis to incur a substantial level of costs through approximately 2028. The vast majority of these costs would have been incurred irrespective of management inefficiency in order to comply with EPA CCR requirements. When DEC initially constructed coal ash impoundments and transported CCRs to them many decades ago, it did so in accord with the prevailing industry practices at the time, especially in this part of the country. In part and over time this was in response to environmental regulations requiring the removal of pollutants such as CCRs from the coal plant smokestacks to reduce air pollution.

Over time, the EPA and other environmental regulators have scrutinized the impact of CCRs in unlined repositories on surface and ground water and have assessed the extent to which harmful constituents in CCRs exceed those naturally occurring in the environment and their impact on human health. One long-lasting debate before EPA addressed the extent to which CCRs should be classified as hazardous waste under RCRA, a debate only recently resolved. Had EPA classified CCRs as a hazardous waste, economic reuse in all likelihood would have become an impossibility.

Another area of scrutiny has been the appropriate need for and method of remediation with respect to closing and potentially moving CCRs from unlined impoundments.

Many of the criticisms of DEC's CCR remediation practices raised in this case, before the federal district court in the criminal proceeding and before other courts and administrative agencies, address issues such as seeps from impoundment dikes, improper maintenance of dikes, lax reporting, exceedances and NPDES violations with respect to surface water discharges. The primary and ultimate remediation however is dewatering and excavation of and transportation from existing unlined impoundments and construction of new lined impoundments or, for older discontinued impoundments that qualify, caps preventing rainwater intrusion. This is where the vast majority of the billions of dollars of CCR remediation costs must be spent. This ultimate remediation step is necessary to prevent most of the leachate from infiltrating groundwater from the bottom of unlined basins, but would have been required irrespective of the harms that constitute other alleged mismanagement. In addition, this remediation process cures other less pervasive environmental and health threats.

Intervenors fault DEC for failure to undertake this remediation process years earlier before being required to do so. The evidence shows that DEC undertook steps toward CCR remediation and incurred costs in anticipation of impending closure but hesitated to spend substantial sums until the requirements became clearer. Had DEC acted in compliance with assertions that it act more aggressively sooner, it would have incurred costs its consumers would have been responsible for then. So from a ratemaking perspective, this Commission's concern, the question of when the remediation should have taken place, now or in the future or twenty years ago, is not determinative of whether the costs of the remediation should be recovered through rates and to what extent. Intervenors are unable to show when DEC should have acted differently in the past or what the increased costs would have been then. The Commission rejects efforts from any source to advance theories in support of discrete disallowances that parties before the Commission have not seen and have therefore been denied any opportunity to analyze and respond. The Commission must depend on parties before it, particularly the Pubic Staff, with the statutory responsibility to audit and respond to general rate case filings to advance theories for cost recovery.

Indeed, whenever undertaken, the costs would have been site specific, and establishing a past cost in this case would be a near impossibility. As DEC would have been required to undertake the remediation at issue in 2015 through 2017, irrespective of other improper actions of which it has been accused and for which it pled guilty to and was sentenced for in the criminal proceeding, any disallowance in this case must be made within the context of these facts. Had DEC acted irresponsibly in neglecting seeps earlier, the remedy would have been pumping the water from the seeps back into the basin, for example. Costs of this remediation would have been negligible in comparison to removing ash or cap-in-place.

DEC 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 DEC through denial of cost recovery for its decision to wait until EPA's CCR determinations in this area were finalized. Had DEC 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, DEC risked unjustified expenditures. In 2015, the EPA announced the Clean Power Plan. 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. Even today efforts to soften the impact of the EPA CCR Rule are under consideration by the current administration. If effectuated, anticipated cost recovery may change in the future.

A significant example of the ambiguity and uncertainty DEC faced in the management of CCR impoundments is illustrated by reference to a November 1, 2004 Long Term Ash Strategy Study Phase Report addressing 1983 and 1984 CCR repositories at DEP's Sutton coal fired plant in New Hanover County referred to in the 2018 DEP order. The 1983 impoundment was unlined and had reached capacity prior to the 2004 report. The 1984 impoundment was lined and was rapidly approaching capacity, and the report identified and classified alternatives for CCR use or disposal to prevent shutdown of the Sutton plant. In the "Problem Description" section of the report, the authoring engineer listed issues either directly or indirectly related to a contribution to the overall ash strategy for the Sutton plant. The issues were described as secondary and not a dictating factor in the solution of the best alternative but as a look at overall environmental structure and stewardship. The first issue addressed the 1983 unlined impoundment that for the most part had ceased to receive CCRs.

> <u>1983 Pond is Unlined</u>
>
> The first issue is that the 1983 ash pond was constructed during a period when it was not required to provide a non-permeable liner, and was constructed with the native sandy soils.[76] This pond has been functionally full since 1983, but is still permitted[77], and is occasionally used when there are issues requiring the 1984 ash pond to be temporarily dry. The current environmental atmosphere is that these ponds will eventually have to [sic] emptied and placed in a lined containment to eliminate the leaching of the ash products into the groundwater system. This is an issue that is not currently being pressed, but it is anticipated that with the tighter environmental conditions it will soon become an emergent issue. This issue is aggravated by the fact that a test monitoring well located 300' from [sic] edge of the 1983 ash pond has shown high levels of arsenic during the past two quarterly tests. This may or may not be related to the unlined ash pond. A recent study by an independent firm indicated this concern may be less than originally thought. It could be mitigated by adding monitoring wells to the NPDES permit, but could still pose an issue in the future.[78] There is also a county well water source approximately 1200' from the test well that is monitored by the county.
>
> Elsewhere in the report under the "Do Nothing" alternative, the author stated:
> It is assumed that the North Carolina Division of Water Quality (NCDWQ) will require the 1983 ash pond to be emptied and lined to comply with current ash pond regulations. For the purpose of this study it is estimated that there is a 5% chance annually of the ash pond required to be relined

[76] The reference to "native sandy soils" is significant. Its characterization for absorption of leachates is greater than for the clay soils of the Piedmont at issue with respect to the DEC impoundments in this case.

[77] The 1983 impoundment operated pursuant to a DEQ permit. Obviously, at the date of the report, DEQ was not requiring closure or dewatering and removal of the CCRs. This would not occur until passage of the CCR Rule and CAMA years later.

[78] This recitation is consistent with the comprehensive testimony of witness Wells in this case that with respect to the types of contaminants at issue from CCR impoundments, they exist in naturally occurring quantities in the soil. Monitoring wells showing exceedances above standards are not dispositive without measurement of naturally occurring constituents.

starting 2007, and that in 2013 there will be a 10% chance annually thereafter until 2019.

In 2018, it is less than clear as to what the author refers to as the "current environmental atmosphere" or "current ash pond regulations." The author of the report does not elaborate or explain. Were the Commission to attempt to read the author's mind, this would be mere speculation. To the extent DEQ was enforcing them, DEQ was not requiring DEC to take additional steps to comply. As the report states, the 1983 impoundment was operating pursuant to a DEQ permit, and DEQ had not required closure. The author repeatedly uses the word "assumes" and "anticipated" to predict the environmental regulators' future intent. The author's speculation as to if and when unlined impoundments might have to be dewatered and excavated was off the mark. With respect to the 1983 Sutton unlined impoundment, that impoundment will never be relined. If it had been relined as the author suggests, the Company would have been required to move the CCR's twice, once to some new location, then back to the newly relined 1983 repository. Such is not the case for compliance with EPA CCR rules and CAMA where the CCR's were moved only once -- deposited in a new, lined landfill.[79]

The EPA's CCR rule was passed in 2015, and the NC CAMA was passed in 2014 with deadlines a number of years beyond that. DEC did not choose the alternative recommendation in the report, creation of an industrial park, nor did it excavate the unlined 1983 impoundment in response to the report. The report contains no recommendation to excavate the 1983 impoundment solely for environmental remediation. The Commission is unable today to say how in the past the 1983 impoundment would have been excavated and how the excavated CCRs would be placed in a lined impoundment, what the cost would have been and what cost recovery treatment would have been appropriate. Indeed, the 1983 impoundment today is being excavated pursuant to express EPA and DEQ guidelines, and the parties to the DEP case vigorously contest how compliance with these requirements should be accomplished and what the cost should be.

The purpose of the report was to determine the best course based upon the fact that the 1984 lined ash pond was reaching capacity and would be non-operational by June 2006. It is important to note that the author was indicating that the 1984 ash pond would be non-operational under the NPDES permit due to capacity constraints as opposed to environmental concerns.

Intervenors are advocating substantial disallowances in this case for expenditures DEC incurred to meet CAMA deadlines, such as at Dan River, Riverbend, or Buck, before all of the regulatory requirements had been finalized. A substantial area of contention is

[79] Intervenors are highly critical of DEC for failure to take action in response to consultants, in-house investigative teams and outside research entities such as EPRI before 2015. However, quite inconsistently, when it comes to criticizing DEC's actions after 2015, they assert that DEC was remiss in not stopping short of what SCDHEC wished for remediation of W.S. Lee and the consultant for the selenium treatment at Riverbend. They contend DEC spent too much in complying with these required or suggested remediation steps.

exceedances and environmental violations addressing harmful constituents in coal ash even though determinations with respect to naturally occurring levels of background concentrations of these constituents have not been established. Rules for regulating seeps from dikes are yet to be finalized. As testified to by witness Wells, with respect to covered engineered seeps, DEQ and DEC have been in long-standing negotiations as to whether seeps are a violation of the law and since 2014 whether seeps should be covered by the NPDES permit. Even as DEC continues to remediate, state regulatory agencies must review and approve the process and may impose additional restrictions, limitations and requirements. Even subsequent to EPA CCR rules and CAMA, the General Assembly enacted the Mountain Energy Act of 2015, changing the requirements for the Asheville plant remediation for DEP. Closure options for each of the CCR impoundments are site specific. Even now, Intervenors criticize the selection of repositories for beneficiation. Intervenors contend DEC spent too much to comply with CAMA. As discussed below, others advocate that this Commission supersede the authority of environmental regulators and require excavation of all DEC's impoundments and prohibit cap-in-place and spend more than DEC contemplates irrespective of what DEQ may require. The Commission is unable to recreate the past and place a price tag on remediation costs that might have been incurred in anticipation of environmental requirements.

Intervenors maintain that DEC should have addressed CCR remediation in years prior to EPA's CCR regulations and CAMA when the industry began to grow concerned over potential CCR environmental degradation. Under this theory, remediation costs would have been lower then and as a consequence CCR remediation costs DEC seeks for recovery beginning in 2015 are excessive and should be disallowed in whole or in part.

The most significant shortcoming in this theory is that no attempt has been made by any party to this case to demonstrate what the costs would have been in earlier years that theoretically would be so much lower as to make the 2015 and subsequent CCR remediation costs unnecessary or excessive. To the extent efforts are made in this case after the record has closed, as was the case in the DEP case, DEC has had no opportunity to respond and any such effort is unfair and inappropriate.

Before EPA CCR rules and CAMA, DEC's impoundments were operated under permits authorized and overseen by DEQ or its predecessor, clients of the AGO. DEQ suggested no requirements that DEQ dewater the impoundments, remove the CCRs and transport them to lined landfills or install caps in place. No requirements existed for DEC to follow. Had DEC undertaken impoundment closure, DEQ would have been required to oversee the process, but of what that oversight would have consisted is unknowable today.

DEC has incurred costs beginning in 2015 and thereafter pursuant to elaborate EPA and CAMA requirements under close scrutiny and oversight from DEQ. Parties to this case hotly contest and dispute the steps DEC has taken to comply and assert that DEC's expenditures have been unreasonable.

In an effort to comply with CAMA, DEC identified Buck as a beneficiation site. Public Staff witness Moore argues DEC should have chosen instead Weatherspoon and that DEC therefore spent $10,612,592 too much between January 1, 2015 and November 30, 2017.

In order to comply with CAMA, DEC constructed an onsite landfill of Dan River. Public Staff witness Moore argues that DEC selected the wrong site, the former footprint of the Ash Fill 1, and should not have increased the costs to transport CCR materials offsite. He contends that DEC spent $59,320,890 too much.

In order to comply with CAMA, DEC transported CCRs from the Riverbend Ash Stack to the R&B landfill in Homer, Georgia and to the Brickhaven facility. Public Staff witness Moore contends that the material should have been disposed of at the Marshall plant and DEC spent $489,600 too much.

In order to comply with SCDHEC requirements, DEC attempted to close the regulated ash basin of W.S. Lee and mitigate risks of the unregulated inactive ash basin and fill area. Public Staff witness Garrett disagreed with DEC's decision to immediately begin excavation and transportation from these basins and transport CCRs to the R&B landfill in Homer, Georgia. Witness Garrett testified that DEC spent $27,275,192 too much.

Public Staff witnesses contend that DEC spent $97,698,274 too much to comply with EPA and CAMA. Even with access to steps DEC took and to the compilation of costs DEC incurred, these witnesses encountered difficulty understanding what DEC did. Witness Moore calculated the cost for excavating, transporting and disposing of Ash Stack I at the Dan River off-site to be $83,531,985. This was $3.8 million too high because this amount should have been attributable to excavation and transportation of ash from the Primary Ash Basin. The cost to build the alternative landfill location when accounting for the need to address asbestos and relocate the warehouse building at Dan River increases witness Moore's cost determination by $10,790,900. Witness Moore originally included costs of parcels at Cliffside even though DEC had not requested recovery of those costs. Witness Moore assumed DEC began transport of CCRs from Riverbend to the R&B Landfill beginning May 2015 and continuing to February 2016. However, the DEC contract with Waste Management was for 17 weeks through September 18, 2015.

Witness Moore criticizes DEC for spending too much at Buck, Riverbend, and Dan River <u>to comply with</u> CAMA requirements. Witness Junis criticizes DEC for spending too much at Belews Creek and Riverbend for remediation <u>not required by CAMA</u> for selenium removal. Witness Quarles criticizes DEC for <u>spending too little</u> at Allen and Marshall to remediate by not removing the coal ash from the unlined basins there in disregard of what DEQ <u>may ultimately require for compliance with CAMA</u>. The Commission deems the various Intervenor theories for remediation cost disallowance "all over the map" and deficiently inconsistent.

With so much disagreement over what DEC should have done or is doing to comply with EPA requirements and CAMA, the Commission determines that insurmountable obstacles exist to quantify the alleged offsets that are a fundamental element to Intervenors' disallowance theory. The Public Staff, the agency required by statute to audit rate requests and recommend adjustments, candidly testified that it does not base its recommended equitable sharing recommendations on past DEC imprudence. That agency was unwilling to attempt to speculate what DEC should have done in the past, when it should have acted and, most significantly, what the costs would have been. No other party has undertaken such effort. Without 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.

The Commission would be required to anticipate the difficulty in complying with local ordinances like the ordinance DEC confronted from the City of Danville. The Commission would be required to anticipate the level of community opposition such as that experienced at Riverbend. The Commission would be required to anticipate what, if any, issues the legislature or DEQ might have imposed for beneficiation. The Commission would be required to anticipate the reaction of state or local representatives to DEC's decision to excavate or cap-in-place repositories within their legislative districts. The Commission concludes such tasks are unwarranted.

Intervenor theory on groundwater exceedances is that DEC violates 2L standards whenever monitoring wells show exceedance of standards or where DEC has not installed monitoring wells in addition to those required by DEQ to disprove the existence of exceedances. Some of the exceedances were from measurements taken within the CCR impoundments. The Commission cannot accept this theory. The fallacy of the theory rests on the fact that the undisputed evidence is that all of the constituent elements measured against the standards, including iron, manganese and pH, constituents harmful neither to the environment nor human health, occur naturally in the North Carolina soils irrespective of the proximity of coal ash impoundments. The evidence shows that DEQ by its actions or inactions does not agree that the existence of exceedances without evidence that they are caused by coal ash contamination pose a risk to the environment or human health so as to require immediate remediation. DEQ has established a low priority to DEC's request to add 2L limits to NPDES permits. Although the Commission is not an environmental regulator, it must agree with DEC and DEQ that failure to take the costly actions required to comport with this Intervenor theory falls well short of mismanagement so as to justify some unquantified disallowance of 2015-2017 costs of dewatering and removal of CCRs from unlined pits or construct caps, which will cure exceedances caused by CCR groundwater contamination, if any.

This Commission's responsibility is cost recovery. Environmental regulators must oversee protection of the environment and public health. The Commission's responsibility is to determine whether coal ash remediation costs as required by environmental regulators should be recoverable through rates.

Another factor the Commission must address is the imposition of requirements of CAMA in addition to those of EPA. The evidence in this case is that the level of transportation and beneficiation costs being contested arises from more aggressive CAMA deadlines and uncertainty over the timing of the granting of regulatory permits for replacement impoundments. Except as addressed generically elsewhere, the Commission is reluctant to second-guess specific DEC decisions on its attempts to comply with these requirements in a 20/20 hindsight fashion. Likewise, the Commission is reluctant, except in limited fashion, to penalize DEC for good faith efforts to comply with state statutes irrespective of the factors motivating the General Assembly to impose them.

In his testimony, AGO witness Wittliff asserts that DEC's mismanagement caused CAMA and that costs DEC incurred to comply with CAMA in excess of those to comply with EPA CCR requirements should be disallowed. Witness Wittliff makes no effort to quantify the disallowance he proposes under this theory. In contradiction of its own witness, the AGO in its post-hearing brief argues that all of DEC's 205-2017 CCR remediation costs should be disallowed -- again without showing what DEC's costs should have been before 2015 under the AGO's theory. The AGO insists it is up to DEC to make these calculations for it.

Aside from the unsubstantiated theoretical underpinnings of the Wittliff argument, it is not possible to segregate CAMA 2015-2017 costs from EPA CCR costs. Indeed, a major prudency disallowance advocated by the Public Staff addresses 2015-2017 remediation costs at DEC's W.S. Lee plant in South Carolina. DEC was required to meet deadlines beyond those imposed by the EPA but not as a result of CAMA, which did not apply outside of North Carolina.

Conversely, the Commission is unable to find DEC faultless in the dilemma it has faced. Much testimony addresses the issue of whether DEC's mismanagement of CCRs "caused" the General Assembly to enact CAMA. DEC argues that other nearby states enacted CCR remediation statutes in addition to EPA's CCR rules, and that the Dan River spill affected the timing but not the substance of CAMA's requirements. The Commission is unable to conclude that DEC mismanagement is the primary cause of CAMA. Just as a preamble never accepted cannot legally justify legislative intent, neither can the absence from earlier versions of CAMA that would have addressed cost recovery. Nevertheless, the provisions of CAMA directly address remediation of DEC CCR repositories and impose accelerated deadlines with respect to them. The Commission therefore is unable to conclude that DEC mismanagement to which it admitted in the federal criminal court proceeding was not at least a contributing factor. Even DEC witness Wright's testimony suggests as much. While DEC presents persuasive evidence that its alleged mismanagement has not been supported and was not the cause of CAMA, this evidence is difficult to reconcile with its admissions and guilty pleas before the federal district court in the criminal proceeding. DEC represented that it mismanaged its CCR activities.

The Commission's conclusions with respect to the impact of DEC's mismanagement as a contributing factor to the enactment of CAMA are significant in two ways. First, the Commission determines that this conclusion adds support to the Commission's assessment of a management penalty in the form of cost disallowance arising primarily from the Company's admissions of mismanagement in the federal criminal case. Secondly, it supports the Commission's determination to reject more discrete disallowances such as those addressed by the Public Staff with respect to Buck, Riverbend and Dan River transportation costs. The Commission deems these costs traceable to CAMA timelines, implemented in part in response to DEC's CCR management practice, but is unpersuaded that the quantification of the costs is accurate or that the severity of the proposed disallowances is justified. Consequently, the Commission takes the incurrence of these costs into account in establishing the amount of its management penalty.

DEC admits to pervasive, system-wide shortcomings such as improper communication among those responsible for oversight of coal ash management. As stated above, while the Commission cannot state that CAMA would not have been passed or that its requirements other than accelerated deadlines would have been less onerous but for DEC's mismanagement of its CCR activities, neither can it state that DEC activities were without impact on the CAMA provisions that have resulted in increased costs that are at issue in this case. More fundamentally, in its admissions and pleas of guilty before the federal district court, DEC has outlined acts of criminal negligence through management misfeasance. In so doing, the Commission determines that, irrespective of CAMA, DEC has placed its consumers at risk of inadequate or unreasonably expensive service.

The Commission must regulate DEC pursuant to the requirements of Chapter 62 to see that compatibility with environmental well-being is maintained. N.C. Gen. Stat. § 62-2(a)(5). Service is to be provided on a well-planned and coordinated basis that is consistent with the level of energy needed for the protection of public health and safety for the promotion of the general welfare as expressed in the state energy policy, N.C. Gen. Stat. § 62-2(a)(6). All companies are prevented from violating environmental statutes. N.C. Gen. Stat. § 143-215.1. DEC is required to maintain safe and reliable service. As an electric utility, safety usually means safe electric service. In the context of this case, the Commission also determines that it means assuring safe operation of its coal-burning facilities so as not to render the environment unsafe. Declining to acquire and install a relatively inexpensive camera in a decades-old storm water drainage pipe over which the large coal ash impoundment is constructed when engineers repeatedly recommend such installation does not comply with a duty to provide safe service.

Fortunately, Dan River was a plant where coal-fired generation had been discontinued at the time of the 2014 spill. Risers in disrepair, inadequate oversight of impoundment dikes and seeps have not resulted in catastrophic failures causing plants to be taken offline or service disruptions, but DEC's irresponsible management of its impoundments over a discrete period of time placed its customers at risk of inadequate service and has resulted in cost increases greater than those necessary to adequately maintain and operate its facilities.

Consequently, having pled guilty to management criminal negligence, DEC cannot go without sanction in the form of cost of service disallowances. At the same time, to the extent the Dan River plant spill has contributed to the CCR remediation expense that otherwise would have been lower, the Company has borne responsibility for Dan River remediation costs without ratepayer support. The Company has been penalized by the federal district court. It cannot seek cost recovery of these monetary penalties or remediation assessments. Further, the mismanagement to which DEC pled guilty was only for a fraction of the time DEC operated the impoundments. No evidence was submitted that DEC's management was imprudent from the initial date of operation. The penalties imposed by this Commission take the form of denial of recovery of a return on historic remediation costs that reduce a portion of costs that ratepayers otherwise would have borne. The Commission deems double penalization inappropriate as an unwarranted penalty that has a tendency to unduly threaten the long-term overall wellbeing of the Company, a situation not in the best interest of its consumers.

A major difficulty the Commission confronts in this case is the identification and quantification of the appropriate CCR remediation adjustment to incurred costs. The record does not contain evidence appropriately quantifying the cost DEC incurred with respect to discrete remediation activities.[80] The Public Staff's witnesses' encountered difficulty in quantifying and supporting the costs for the alleged Cliffside, Riverbend and Dan River disallowances and other less specific ones motivates the Commission to resist imposition of discrete cost disallowances. The Commission deems disallowance of the totality of costs, as some parties advocate, unjustified. The Commission deems full recovery, as DEC advocates, unjustified. The Commission deems the Public Staff's 51/49 equitable sharing disallowance unfairly punitive and of questionable legal sustainability. The Commission deems requirements that more costs be imposed than DEQ might require without cost recovery unjustified. Moreover, the Commission deems it inadvisable to approve or suggest future disallowances with respect to CCR remediation expenditures as far away as 2028 and beyond. In sum, the Commission cannot agree with any of the parties in this case and must fashion and quantify a remedy different from any of those advocated before it.

The Commission operates under a legislative mandate that requires it to fix rates that will allow a utility "by sound management" to pay all of its reasonable operating costs, including maintenance, depreciation, and taxes, and earn a fair return on its investment. N.C. Gen. Stat. § 62-133(b)(4). State ex rel. Utils. Comm'n v. General Telephone Co.,

[80] As the Commission recited in its order in the DEP case, AGO witness Wittliff was asked whether he offered any opinion on what he thought the Company's appropriate amount of recovery under the CCR rule should be. He responded:

> ... I would explain that I'd love to have been able to come up with some extremely precise numbers and explain it all to you where it all made crystal clear sense and you could hang your hat on it and that's the number, we can pin that down. The problem is, is that this is, as we've already - - everyone seems to have observed, is it's an extremely complex case with a lot of moving parts, and it's not as easy to - - to make that sort of definitive statement. Tr. Vol. 15, pp. 77-78.

The same evidentiary shortcoming is present in the record in this case.

285 N.C. 671, 208 S.E.2d 681 (1974). If the Commission finds that a utility has not been soundly managed, it may penalize a utility by authorizing less than a "fair return." Id.[81] The Commission must quantify the penalty by making a finding of what return would have been allowed if there were sound management. Id. The North Carolina Supreme Court has stated that "[t]he size of the penalty is left to the judgment of the commission, but must be based upon substantial evidence, and the penalty must not result in a confiscatory rate of return." Id. General Telephone addressed a rate of return on rate base penalty for mismanagement resulting in inadequate service. In this case, DEC's mismanagement takes the form of admitted inadequate oversight of its CCR activities that placed service to its consumers at risk and, at least indirectly, increased costs. As the penalty is a defined monetary penalty rather than a percentage return penalty, the impact on cost of service would be the same if it had been a rate of return on rate base penalty.

Consequently, the Commission in the exercise of its judgment and discretion, determines that a management penalty in the approximate sum of $70 million is appropriate with respect to DEC CCR remediation expenses accounted for in the earlier established ARO with respect to costs incurred through the end of the test year as adjusted. This penalty is based on the totality of evidence contained in the record, as recited in detail above, and does not result in confiscation. Had the Commission not imposed this penalty, the ARO costs would have been amortized over five years with a full authorized return on the unamortized balance. As the Commission has addressed comprehensively above in this order, the Commission possesses the discretion to authorize a return on the unamortized balance. The unamortized balance is not a recurring test year operating expense. The annual amortization of the balance (return of not return on) is the amount that equals to operating expense pursuant to N.C. Gen. Stat. § 62-133(b)(3). The penalty will be imposed by reducing the resulting annual revenue requirement by $14 million (from the return on the unamortized balance on the capitalized costs) for each of the five years, resulting in an approximate $70 million management penalty. While this penalty differs in form from that in General Telephone, the Commission determines that conceptually General Telephone provides appropriate precedent. By imposing this management penalty, the Commission does not suggest that further penalty or disallowances with respect to past DEC actions or inactions will be imposed with respect to future CCR remediation expenses. The size of the penalty meets judicial requirements as it is quantified and is not confiscatory.

With respect to CCR remediation costs to be incurred during the period rates approved in this case will be in effect, the Commission determines that the "run rate" or the "ongoing compliance costs" mechanism advocated by DEC will not be approved. By requesting the creation of an ARO, in addition to the run rate, DEC concedes that treating CCR expenditures as a recurring test year expense is inadequate. Future annual costs, the evidence shows, are predicted to vary substantially from year to year. Instead, CCR

[81] See also State ex rel. Utils. Comm'n v. Morgan, 277 N.C. 255, 177 S.E.2d 405 (1970) (holding "that it is not reasonable to construe [the statute] to require the Commission to shut its eyes to 'poor' and 'substandard' service resulting from a company's willful, or negligent, failure to maintain its properties [] and it is obvious that consistently poor service, attributable to defective or inadequate or poorly designed equipment or construction justifies a subtraction …").

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. While this ratemaking treatment will, in limited fashion, diminish the quality of DEC's earnings, over time, assuming reasonable and prudent CCR management practices, it permits appropriate recovery. Prior to the next rate case, the Commission shall require that DEC provide a detailed accounting of its Cost of Removal Reserve for its steam assets and how the Company is utilizing this Cost of Removal Reserve.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 73

The evidence supporting this finding and conclusions is contained in the Company's verified Application and Form E-1, the testimony and exhibits of the witnesses, the Stipulation, and the entire record in this proceeding.

Public Staff witness Maness stated that coal ash costs prudently incurred from 2015 through 2017 (i.e., costs not subject to Public Staff recommended disallowances apart from equitable sharing) should be allowed provisional cost recovery. Tr. Vol. 22, pp. 63-64. He explained that the reasonableness of some of those costs may depend on the outcome of legal proceedings or other legal determinations, as described by witness Junis. Id. Witness Junis testified that environmental lawsuits had not been resolved for several DEC plants. Tr. Vol. 26, p. 732.

Witness Wright argued against witness Maness' recommendation of provisional cost recovery. Witness Wright stated that provisional rates appeared to be retroactive ratemaking and the utility should not be subject to hindsight review. Tr. Vol. 12, errata pp. 156-39-40.

Provisional cost recovery is appropriate in certain circumstances. However, the Commission is not persuaded that there is good cause to order provisional cost recovery of DEC's CCR costs that are approved in this Order. The Commission has weighed the Public Staff's and other intervenors' concerns about the pending insurance lawsuits and pending determinations by DEQ, EPA, and certain courts, that will establish whether past actions of DEC amount to environmental violations against the uncertainty that is inherent in provisional rates. With regard to the insurance litigation, DEC has committed that insurance proceeds recovered by DEC will benefit ratepayers as an off-set to DEC's CCR costs. Further, the insurance proceeds are not known and measurable as of the end of the test year. Moreover, the Commission has included in this Order specific reporting requirements and other conditions with which DEC must comply regarding the insurance proceeds.

With respect to pending determinations by EPA and DEQ, the Commission is not inclined to delay its work in order to wait for these agencies to complete their work. As a result, on balance the Commission finds and concludes that it will not order that the CCR cost recovery in this docket is provisional.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 74-75

The evidence supporting these findings and conclusions is contained in the Company's verified Application and Form E-1, the testimony and exhibits of the witnesses, the Stipulation, and the entire record in this proceeding.

DEC has used a demand allocation factor to allocate its costs related to its compliance with state and federal environmental regulations regarding coal ash pond closures in this case. Tr. Vol. 19, p. 39. Additionally, the Company has identified specific CAMA-related costs and allocated these costs directly to North Carolina customers. Tr. Vol. 6, p. 314.

Public Staff witness Maness recommended applying a jurisdictional allocation of all coal ash expenditures by a comprehensive system factor. Tr. Vol. 22, pp. 66-68. He stated that his adjustment removed the distinction between costs DEC described as CAMA-only and the remainder of the coal ash costs. Id. at 66. He stated that for CAMA-only costs, DEC utilized North Carolina retail allocation factors that do not allocate any of the system level costs to South Carolina retail operations. Id. at 67. He opined that even though some of the costs incurred by DEC are being incurred pursuant to North Carolina law, it is fair and reasonable to allocate those costs to the entire system because the coal plants associated with the costs are being, or were, operated to serve the entire DEC system. Id. Public Staff witness Maness also stated that he used the energy allocation factor to allocate system-level coal ash costs to North Carolina retail operations, rather than the demand-related production plant allocation factor utilized by the Company. Id. at 67-68. Witness Maness recommended that an energy allocator be used to determine the North Carolina retail portion of the coal ash costs because they are being incurred due to the fact that the coal ash was produced by the burning of coal to produce energy over the years, and like the cost of coal, should be allocated by energy, and not peak demand. Id. at 68.

NCSEA witness Barnes also objected to DEC's classification of coal ash costs as demand related. He argued that this approach is contrary to cost causation principles because coal ash is a by-product of consumption of a fuel, and the volume of coal ash produced is associated with overall energy use, not demand during a single hour of the year. He recommended that all coal ash remediation costs approved for recovery be allocated using an energy allocator. Tr. Vol. 20, p. 62.

Additionally, CIGFUR III witness Phillips testified in support of the Company's proposed allocation of coal ash management costs on a demand basis, stating that such allocation "is appropriate and should be approved." Tr. Vol. 26, p. 258. CIGFUR III witness Phillips further testified that coal ash is not a fuel, but an environmental waste with no energy potential. Id. at 271. Witness Phillips also stated that compliance costs associated with coal ash remediation did not exist at the time the coal was burned, but arose more recently. Id. Therefore, remediation costs should not be allocated on a kilowatt-hour basis. Id. Further, the investment associated with coal ash ponds is typically included in generation plant accounts and should be allocated on the same basis and DEC allocates generation plant based on demand. Id.

In her rebuttal testimony, DEC witness McManeus opposed witnesses Maness' recommendation that the costs DEC identified as "CAMA only" be allocated to all jurisdictions, instead of directly assigning these costs to North Carolina. Tr. Vol. 6, p. 313. Witness McManeus explained that while she generally agrees that the costs of a system should be borne by all of the users of the system, the Company has identified very specific cost categories that should be treated as an exception to this general rule due to their nature as being unique to North Carolina. Id. These cost categories include groundwater wells used specifically for CAMA purposes and permanent water supplies provided to North Carolina customers pursuant to CAMA. Tr. Vol. 14, p. 120. Witness McManeus explained that this allocation is consistent with prior Commission decisions related to the Company's costs of complying with other North Carolina laws including REPS and the North Carolina Clean Smokestacks rule. Tr. Vol. 6, pp. 313-14. Because the Commission has allowed the Company to recover 100% of its costs associated with complying with those North Carolina laws, the Company believes it is also appropriate that CAMA-specific costs be directly assigned to North Carolina customers. Id. at 314.

Additionally, Company witness Hager responded to witnesses Maness' and Barnes' recommendation to classify coal ash costs as demand related. Witness Hager explained that the costs in question are associated with compliance with federal and state environmental requirements related to closing coal ash ponds. Tr. Vol. 19, p. 39. Residual end of life costs typically and logically follow the cost of the plant, which is allocated based on demand. Id. This is supported by the fact that end of life costs (removal costs) and salvage values are factored into depreciation rates, and depreciation expenses are allocated based on demand. Id. Witness Hager also noted that it is also consistent with end-of-life nuclear fuel costs in nuclear decommissioning costs which are allocated based on demand. Id. at 39-40.

The Commission finds and concludes, with respect to the above-stated adjustments, that it is appropriate to (1) allocate the costs DEC has identified as "CAMA Only" costs by the comprehensive allocation factor, rather than a factor that does not allocate costs to the South Carolina retail; and (2) allocate all coal ash expenditures by the energy allocation factor, rather than the demand-related production plant allocation factor. Regarding the jurisdictional allocation, the Company had directly assigned costs for certain groundwater wells and permanent water supplies to North Carolina on the grounds that such costs were mandated by CAMA and were unique to North Carolina. Tr. Vol. 6, pp. 259, 313-14; Tr. Vol. 14, p. 134. In contrast, witness Maness argued the coal plants had served the entire North Carolina and South Carolina system of DEC, so the costs should be allocated across both jurisdictions. Tr. Vol. 22, pp. 66-67. Regarding the allocation factor, the Company recommended the demand-related factor (Tr. Vol. 6 p. 314; Tr. Vol. 19, pp 39-40), whereas the Public Staff argued for the energy-related factor because the amount of coal ash is related to the amount of energy produced. Tr. Vol. 22, pp. 67-68. The Commission agrees with Public Staff witness Maness that the amount of coal ash correlates with the amount of energy produced from coal, and that the entire DEC system benefited from that energy. Accordingly, and consistent with the Commission's February 23, 2018, Order in Docket No. E-2, Sub 1142, the Commission finds and concludes that the deferred coal ash costs should be allocated across the entire DEC system, and should be allocated on the energy-related factor.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 76-78

The evidence supporting these findings of fact and conclusions is contained in the Stipulation, the Company's verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

On February 26, 2018, the AGO filed a Stipulation as to Admission of Evidence. The AGO and DEC stipulated that the testimony given by Company witness David Fountain regarding insurance coverage in Docket No. E-2, Sub 1142 (DEP Rate Case), along with the associated exhibits, is appropriate to be admitted into evidence in the present case. The testimony was located in the DEP Rate Case in Volume 7 of the transcript in pages 368 through 505 and AGO Fountain Cross Examination Exhibits 1 through 8.

In its post hearing brief, the AGO requested that the Commission monitor the insurance litigation and contended that it would be appropriate for the Commission to make similar findings and conclusions regarding insurance that it made recently in the DEP Rate Order.

The Commission concludes that DEC should be required to place all insurance proceeds received or recovered by DEC in the Insurance Case in a regulatory liability account and hold such proceeds until the Commission enters an order directing DEC as to the appropriate disbursement of the proceeds. In addition, the regulatory liability account shall accrue a carrying charge at the overall rate of return authorized for DEC in this Order.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 79

The evidence supporting these findings of fact and conclusions is contained in the Stipulation, the Company's verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

With regard to DEC's CCR costs from 2018 forward, DEC witness McManeus testified that DEC is requesting to establish a regulatory asset/liability account and defer to this account the portion in annual rates that is more than DEC's actual costs, or the amount in annual rates that is less than DEC's actual costs. In essence, the asset/liability account would be a tool used to true-up the difference in DEC's next general rate case.

The Commission agrees with DEC's recommended approach, not only for CCR costs, but also for all cost deferral accounts. A deferred cost is not the same as the other cost of service expenses recovered in the Company's non-fuel base rates. A deferred cost is an exception to the general principle that the Company's current cost of service expenses should be recovered as part of the Company's current revenues. When the Commission approves a typical cost of service, such as salaries and depreciation expense, there is a reasonable expectation that the expense will continue at essentially the same level until the Company's next general rate case, at which time it will be reset. On the other hand, when the Commission approves a deferred cost the Commission identifies a specific amount that has already been incurred by the Company, or, in the case of CCR costs, is estimated to be incurred by the Company. In addition, the Commission sets the recovery of the amount over a specific period of time. Further, the Company is directed to record the recovery of the specific amount in a regulatory asset account, rather than a general revenue account. If DEC continues to recover that deferred cost for a longer period of time than the amortization period approved by the Commission that does not mean that DEC is then entitled to convert those deferred costs into general revenue and record them in its general revenue accounts. Rather, the Company should continue to record all amounts recovered as deferred costs in the specific regulatory asset account established for those deferred costs until the Company's next general rate case.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 80-82

The evidence supporting these findings of fact and conclusions is contained in the Stipulation, the Company's verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

The Company presented Revised McManeus Stipulation Exhibit 1 – Updated for Post-Hearing Issues reflecting DEC's revised requested increase incorporating the provisions of the Stipulation, the Company's position on the unresolved issues and the impact of the EDIT decrement riders. Per those exhibits, the resulting proposed revenue requirement increase of the Company is $372,527,000. Boswell Corrected Third Supplemental and Stipulation Exhibit 1, Schedule 1 shows the Public Staff's revised recommended incorporating the provisions of the Stipulation, the impact of the EDIT decrement riders and its adjustments reflecting the Public Staff's position on the unresolved issues. The resulting proposed revenue requirement adjustment by the Public Staff is ($385,697,000).

As discussed in the body of this Order, the Commission approves the Stipulation in its entirety and makes its individual rulings on the unresolved issues as discussed. Due to the intricate and complex nature of some of the issues, the Commission requests that DEC recalculate the required annual revenue requirement as consistent with all of the Commission's findings and rulings herein within 10 days of the issuance of this Order. The Commission further orders that DEC work with the Public Staff to verify the accuracy of the recalculations. Once the Commission receives this filing, the Commission will work promptly to verify the calculations and will issue an Order with final revenue requirement numbers.

In addition, the Commission requests that DEC and the Public Staff provide the Commission with the demand and energy allocation factors that they, respectively, deem appropriate for allocating the CAMA costs to the North Carolina retail jurisdiction.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 83

The evidence supporting this finding of fact and conclusions is contained in the Company's verified Application, the testimony and exhibits of all the witnesses, the Stipulation, and the entire record in this proceeding.

Pursuant to N.C. Gen. Stat. § 62-133(a), the Commission is required to set rates that are "fair both to the public utilities and to the consumer." In order to strike this balance between the utility and its customers, the Commission must consider, among other factors, (1) the utility's reasonable and prudent cost of property used and useful in providing adequate, safe and reliable service to ratepayers, and (2) a rate of return on the utility's rate base that is both fair to ratepayers and provides an opportunity for the utility through sound management to attract sufficient capital to maintain its financial strength. See N.C. Gen. Stat. § 62-133(b). DEC's continued operation as a safe, adequate, and reliable source of electric service for its customers is vitally important to DEC's individual customers, as well as to the communities and businesses served by DEC. DEC presented credible and substantial evidence of its need for increased capital investment to, among other things, maintain and increase the reliability of its system and comply with environmental requirements.

Based on all of the evidence, the Commission finds and concludes that the revenue requirement, rate design and the rates that will result from this Order strike the appropriate balance between the interests of DEC's customers in receiving safe, reliable and efficient electric service at the lowest possible rates, and the interests of DEC in maintaining the Company's financial strength at a level that enables the Company to attract sufficient capital. As a result, the Commission concludes that the revenue requirement and the rates that will result from that revenue requirement established as a result of this Order are just and reasonable under the requirements of N.C. Gen. Stat. § 62-30, et seq.

IT IS, THEREFORE, ORDERED as follows:

1. That the Stipulation filed by DEC and the Public Staff on February 28, 2018, is hereby approved in its entirety.

2. That the Lighting Settlement entered into by DEC and NCLM, Concord, Kings Mountain, and Durham, is hereby approved in its entirety.

3. That DEC shall recalculate and file the annual revenue requirement with the Commission within 10 days of the issuance of this Order, consistent with the findings and conclusions of this Order and the Stipulation. The Company shall work with the Public

Staff to verify the accuracy of the filing. DEC shall file schedules (North Carolina Retail Operations – Statement of Rate Base and Rate of Return, Statement of Operating Income, and Statement of Capitalization and Related Costs) summarizing the gross revenue and the rate of return that the Company should have the opportunity to achieve based on the Commission's findings and determinations in this proceeding. In addition, DEC and the Public Staff shall provide the Commission with the demand and energy allocation factors that they, respectively, deem appropriate for allocating the CAMA costs to the North Carolina retail jurisdiction.

4. That DEC is hereby authorized to adjust its rates and charges in accordance with the Stipulation and findings in this Order effective for service rendered on and after the following day after the Commission issues an Order accepting the calculations required by Ordering Paragraph No. 3.

5. That the Commission shall issue an Order approving the final revenue requirement numbers once received from DEC and verified by the Public Staff as soon as practicable.

6. That the appropriate revenue requirement for the first four years shall be reduced by the annual State EDIT rider decrement of $60,102,000.

7. That it is appropriate to recognize a $211,512,000 per year reduction in DEC's revenue requirement to reflect the current 21% Federal corporate income tax rate in DEC's base rates.

8. That DEC's proposed $200 million per year credit metric mitigation measure is denied.

9. That DEC shall continue to maintain all EDIT related to the Tax Act in a regulatory liability account for three years or until its next general rate case, whichever is sooner, at which point it will be returned to DEC's customers with interest reflected at the overall weighted cost of capital approved in this case of 7.35%. If DEC has not filed an application for a general rate case proceeding by June 22, 2021, it shall file its proposal by that date to flow back to its ratepayers both the protected and the unprotected EDIT generated due to the Tax Act. The federal EDIT flowback proposal should include all workpapers that support the proposed calculations. The Public Staff is specifically requested to file comments on the proposal by no later than July 22, 2021. Other parties also may file comments on the proposal by no later than July 22, 2021.

10. That DEC's request to establish a rider to recover Power Forward costs is denied.

11. That DEC's request, as an alternative to a rider, to establish a regulatory asset for the deferral of Power Forward costs is denied.

12. That DEC is instructed to collaborate with the intervening parties, through the generic and DEC-specific Integrated Resource Planning and Smart Grid Technology

Plan docket, toward the goal of resolving some or all of the issues surrounding grid modernization and the most appropriate cost recovery mechanism for such costs.

13. That the Pilot Grid Rider Agreement and Stipulation is disapproved.

14. That the Company shall implement an increment rider, beginning on the effective date of rates in this proceeding, and expiring at the earlier of (a) May 31, 2020,[82] or (b) the last day of the month in which the Company's actual coal inventory levels return to a 35-day supply on a sustained basis, as defined in this Order, to allow the Company to recover the additional costs of carrying coal inventory in excess of a 35-day supply (priced at $73.23 per ton). The Company shall adjust the rider annually, concurrently with its DSM/EE, REPS, and fuel adjustment riders.

15. That on or before March 31, 2019, the Company, in consultation with the Public Staff, shall complete an analysis showing the appropriate coal inventory level given market and generation changes since the Company's rate case in Docket No. E-7, Sub 1026.

16. That the approved base fuel and fuel-related cost factors (excluding regulatory fee), by customer class, are as follows: 1.7828 cents per kWh for the Residential class, 1.9163 cents per kWh for the General Service/Lighting class, and 2.0207 cents per kWh for the Industrial class.

17. That the Company is hereby, authorized to establish a regulatory asset for deferral of post in-service costs for Lee CC, as described herein. These costs shall be amortized over a four-year period.

18. That DEC's request to cancel the Lee Nuclear Project is granted.

19. That DEC's request to recover its project development costs relating to the Lee Nuclear Project is granted, with the exception of costs relating to the Visitors Center and the 2018 AFUDC, as described herein.

20. That the balance of Lee Nuclear Project development costs, adjusted to remove land costs, shall be moved from CWIP Account 107 to regulatory asset Account 182.2 and amortized over a 12-year period, and that the Company shall not earn a return on the unamortized balance.

21. That the Public Staff's proposal that the Company be required to refund to customers $29 million per year relating to the Company's NDTF is hereby, denied.

22. That the depreciation rates proposed by DEC in this case, as modified by this order, are approved.

[82] The Company may request an extension of the May 31, 2020 date.

23. That the aspects of rate design agreed upon in the Stipulation are approved and shall be implemented.

24. That the Company shall increase the monthly BFC for the residential rate class (Schedules RS, RT, RE, ES and ESA) to $14.00. The BFC for other rate schedules shall remain unchanged.

25. That the Company is hereby authorized to establish a regulatory asset to defer and amortize expenses associated with the Customer Connect project. The regulatory asset account shall accrue AFUDC until the DEC Core Meter-to-Cash release (Releases 5-8) of the Customer Connect project goes into service or January 1, 2023, whichever is sooner. At that point, the costs will be amortized over 15 years.

26. That DEC shall file reports regarding the development, spending, and accomplishments of the Customer Connect project each year by February 15 for the next five years or until the Customer Connect project is fully implemented, whichever occurs later. Further, DEC and the Public Staff shall develop the reporting format for the annual Customer Connect project report and file the format with the Commission within 90 days of this Order.

27. That DEC shall prepare and file a lead-lag study in its next general rate case.

28. That DEC's request to recover its AMI costs of $90.9 million in this proceeding is hereby approved.

29. That within six months of the date of this Order, DEC shall file in this docket the details of proposed new time-of-use, peak pricing, and other dynamic rate structures that will, among other things, allow ratepayers in all customer classes to use the information provided by AMI to reduce their peak-time usage and to save energy.

30. That DEC's costs for AMR meters replaced by AMI shall be recovered over a 15-year period.

31. That the Company's proposal for a JRR, as modified by this Order, and the JRRR are hereby approved for a one-year pilot with an option to renew it for a second year if the Company provides evidence that the JRR is achieving its intended purpose.

32. That the JRR and JRRR revenues shall be reported to the Commission annually, if the JRR is in effect more than one year, and the JRRR shall be reviewed and will be subject to adjustment annually coincident with DEP's December fuel adjustment to match anticipated recovery revenues and true-up any past over-or under-recovery.

33. That due to the uncertain date of implementation, compliance tariffs shall be filed prior to implementation of the JRRR and customers shall be notified by bill insert or message upon implementation.

34. That with respect to the Company's vegetation management program, the Company shall eliminate the 13,467 miles of Existing Backlog, as described herein, within five years after the date rates go into effect in this proceeding.

35. That any accelerated amount of expenditures to eliminate the Existing Backlog shall not be used to increase the level of vegetation management expenses in future proceedings, but shall not prohibit the Company from seeking adjustments for vegetation management contractor increases.

36. That DEC shall provide a report annually to the Commission with the following information: (1) actual 5/7/9 and Existing Backlog miles maintained in the previous calendar year; (2) current level of Existing Backlog miles; (3) vegetation management maintenance dollars budgeted for the previous calendar year for 5/7/9 and Existing Backlog; and (4) vegetation management maintenance dollars expended in the previous calendar year for 5/7/9 and Existing Backlog.

37. That the proposed amendments to DEC's Service Regulations are hereby approved.

38. That the Public Staff shall facilitate discussions with the electric utilities to evaluate and document a basis for continued use of minimum system and to identify specific changes and recommendations as appropriate. If the Public Staff ultimately recommends an alternative approach to minimum system as a result of this review, then the support for that position should be clearly defined. The Public Staff shall submit a report on its findings and recommendations to the Commission no later than the end of the first quarter of 2019 in a new, generic electric utility docket to be established by the Chief Clerk for this purpose.

39. That DEC shall file annual cost of service studies based on Winter Coincident Peak as well as the SCP and SWPA methodologies. In its next general rate case, the Company shall prepare cost of service studies based on each of these methodologies.

40. That DEC's proposal to discontinue Residential Water Heating Service Controlled/Sub Metered Schedule is approved.

41. That DEC shall recover the actual coal ash basin closure costs DEC has incurred during the period from January 1, 2015, through December 31, 2017, in the amount of $545.7 million, to be adjusted based on the allocation factors to be provided by DEC and the Public Staff pursuant to Ordering Paragraph No. 3, and DEC is authorized to establish a regulatory asset as requested in the Company's petition in Docket No. E-7, Sub 1110. These costs shall be amortized over a five-year period, with a return on the unamortized balance and then reducing the resulting annual revenue requirement by $14 million for each of the five years.

42. That DEC shall not be allowed to recover on an ongoing basis $201.3 million in annual coal ash basin closure costs, subject to true-up in future rate cases. DEC is authorized to record its January 1, 2018 and future CCR costs in a deferred account until its next general rate case. This deferral account will accrue a return at the overall rate of return approved in this Order.

43. That within 10 days of the resolution by settlement, dismissal, judgment or otherwise of the litigation entitled Duke Energy Carolinas, LLC, et al. v. AG Insurance SA/NV, et al., Case No. 17 CVS 5594, Superior Court (Business Court), Mecklenburg County, North Carolina (Insurance Case), DEC shall file a report with the Commission explaining the result and stating the amount of insurance proceeds to be received or recovered by DEC. This reporting requirement shall apply even if the case is appealed to a higher court.

44. That DEC shall place all insurance proceeds received or recovered by DEC in the Insurance Case in a regulatory liability account and hold such proceeds until the Commission enters an order directing DEC regarding the appropriate disbursement of the proceeds. The regulatory liability account shall accrue a carrying charge at the overall rate of return authorized for DEC in this Order.

45. That if DEC receives revenue for any deferred cost for a longer period of time than the amortization period approved by the Commission for that deferred cost, the Company shall continue to record all revenue received for that deferred cost in the specific regulatory asset account established for that deferred cost until the Company's next general rate case.

46. That the Commission's approval in the Order for deferral accounting and other accounting procedures is without prejudice to the right of any party to take issue with the amount of or the accounting treatment accorded these costs in any future regulatory proceeding.

47. That within 30 days of this Order, but no later than ten business days prior to the effective date of the new rates, DEC shall file for Commission approval five copies of all rate schedules designed to comply with this Order, accompanied by calculations showing the revenues that will be produced by the rates for each schedule. This filing shall include a schedule comparing the revenue that was produced by the filed schedules during the test period with the revenue that will be produced under the proposed settlement schedules, and the schedule illustrating the rates of return by class based on the revenues produced by the rates for each schedule.

48. That DEC shall submit a proposed customer notice to the Commission for review and approval, and upon approval of the notice by the Commission, shall give appropriate notice of the approved rate adjustment by mailing the notice to each of its North Carolina retail customers during the billing cycle following the effective date of the new rates.

ISSUED BY ORDER OF THE COMMISSION.

This the 22nd day of June, 2018.

NORTH CAROLINA UTILITIES COMMISSION

Linnetta Threatt, Deputy Clerk

Commissioner ToNola D. Brown-Bland concurring in part and dissenting in part.

Commissioner Daniel G. Clodfelter concurring in part and dissenting in part.

Commissioner Charlotte A. Mitchell did not participate in this decision.

DOCKET NO. E-7, SUB 1146
DOCKET NO. E-7, SUB 819
DOCKET NO. E-7, SUB 1152
DOCKET NO. E-7, SUB 1110

Commissioner Daniel G. Clodfelter, concurring in part and dissenting in part:

As to a very large number of the myriad issues decided in the Commission's Order in these consolidated cases, I concur in the results reached by the majority. On four topics, however, I would reach different outcomes, and I write separately here to explain my dissent. To summarize my differences from the majority:

I. I would disallow recovery of $244,433,678[1] from the expenditures made by the Company during 2015, 2016, and 2017, related to closure of waste coal ash storage facilities at the Company's eight coal-fired generating plants and for permanent disposal of the waste ash from those facilities, on the grounds that these amounts, in some instances, represent expenditures that were imprudently incurred and, in other instances, represent amounts that the Company imprudently failed to recover in prior rates.

II. For all allowed costs incurred during the period 2015 through 2017, as to the closure of the waste ash storage units and disposal of the ash, I would allow deferral and recovery amortized over a period of five years, but without allowance of any rate of return on the unamortized balance. I would so decide on the grounds that, as to some of such costs, allowance of a rate of return is not authorized by law and, as to all of such costs, the record presented in this case does not and cannot support allowance of a return as a matter of Commission discretion.

III. I would not authorize any increase in the fixed monthly charge (the so-called "basic facilities charge" or "BFC") imposed on residential rate classes on the grounds that there is no evidence in the record to support any such increase.

IV. I would permit the Company to defer to a regulatory asset account its costs for deployment of AMI meters, without a carrying charge, on the grounds that the record as it now stands cannot support a finding that this investment is reasonable or prudent.

In the following sections, I discuss the evidence and rationale for these conclusions in more detail.

[1] This total, as with the other amounts discussed in this section, are systemwide numbers and do not represent the North Carolina retail allocation. The data presented by the Company on waste ash expenditures were all on a systemwide basis.

I. Cost Recovery for Permanent Closure of Waste Coal Ash Facilities

A. General Matters

I start with a truism – each case stands upon its own merit and its own facts. This case follows hard on the heels of the proceeding in Docket No. E-2, Sub 1142 (DEP Rate Case), the general rate case of the Company's affiliate, Duke Energy Progress, LLC (DEP), decided by Commission Order dated February 23, 2018 (DEP Rate Case Order). For issues centering on the storage and disposal of wastes[2] from the burning of coal to generate electricity, the two cases are intimately linked, both factually and legally, but the evidentiary presentation in the two cases was not identical. It is because of the differences that I begin my dissent in this case in the same manner as I began my dissent in the DEP Rate Case[3] with a brief commentary on the state of the evidentiary record.

The evidence presented in this case, and most especially the documentary record that speaks to historical industry practices and standards, and to the Company's own internal policies and practices relating to the management of coal ash wastes, is considerably better developed than it was in the DEP Rate Case. This is largely due to the efforts of the Public Staff and several of the intervenor parties, most especially the Attorney General's Office (AGO). In some instances the new or additional evidentiary materials are pertinent not only to adjudication of the Company's request in this case, but also speak directly to factual issues that were in play in the DEP Rate Case. Sometimes the additional evidence in this case presents issues not considered at all in the DEP Rate Case or opens lines of inquiry not identified in that case. Many documents are dated after the time the Company and DEP became affiliated entities, and they address plant decommissioning and ash basin closure plans, activities, and costs for DEP facilities as well as for the Company's plants. Since these documents were not introduced as part of the record in the DEP Rate Case, they could not form the basis for any of the findings of fact or conclusions of law in DEP Rate Case.

As noted, the differences between this case and the DEP Rate Case are largely manifested in the presentations by the Public Staff and by intervenors. On the other hand, the Company's evidentiary presentation in this case largely mirrored and followed DEP's approach in the DEP Rate Case, an approach I have found less than satisfactory in both cases.[4] The Company depends on the evidence of witnesses whose testimony is very often of questionable value, largely because they lacked pertinent knowledge or

[2] These are euphemistically called sometimes "coal combustion residuals," or "CCRs," for shorthand reference. Because I think this manner of speaking tends to obscure, rather than to clarify the topic, I will continue to call them "wastes," which is in fact what they are.

[3] DEP Rate Case Order at pp. 248-278.

[4] As an initial matter, it is worth a reminder that the Company alone has the burden of proving its case-in-chief when it elects to file an application requesting a rate increase through a general rate case. It is not required of, nor would it be appropriate for, the Commission, the Public Staff, or any other intervening parties to fill in the gaps of any lacking evidence which may be necessary to substantiate the Company's *prima facie* case.

experience of the matters about which they testified, and expressed opinions and conclusions for which they had insufficient foundation. With very limited exceptions, *all* of the evidence in the record for the time prior to 2014 concerning (1) industry standards and practices relative to the management of coal ash wastes, (2) the Company's history of management of coal ash wastes, and (3) the pertinent regulatory requirements relating to coal ash wastes exist in this record only in the form of documents and exhibits offered by the Public Staff or by various other intervenors, or in the form of late-filed exhibits filed by the Company in response to specific questions and requests for information made by members of the Commission, on the record, during the evidentiary hearing. The Company's primary witness on these matters, witness Kerin, only first assumed responsibility for the Company's response to coal ash issues in 2014, without any pertinent prior experience concerning the subject. Notwithstanding this, he testified: "I'm the witness on coal ash for the Company." Tr. Vol. 24, p. 167. Although he testified that he had reviewed various historical documents and Company records as part of his introduction to his new duties, on a number of occasions during the evidentiary hearing, he was confronted with significant historical Company or industry documentation which was altogether unfamiliar to him or which he could not recall well enough to discuss. See, e.g., Tr. Vol. 14, pp. 252-271; Tr. Vol. 15, pp. 12-121. His conclusory testimony that the Company had complied with all pertinent laws and regulations, and had conformed to industry standards prior to 2014, simply cannot be afforded any substantial weight.[5] Company witness Wells, whose experience dated from 2009, displayed a better knowledge of the historical documentary record, but his own experience was limited to environmental compliance matters and did not extend to ash basin design, construction, operation, maintenance, or management issues, or to planning and cost recovery for closure of ash surface impoundments. The Company provided no witness who could testify concerning the Company's budgeting for, accounting for, or recovery of costs

[5] The majority seeks to buttress witness Kerin's credibility concerning historical matters by referring to the peer group of regional utility companies which witness Kerin convened and participated in since having assumed his current role in 2014, and points to the knowledge he has gained from those peer companies about past practices concerning coal ash wastes. Under cross-examination, however, witness Kerin admitted that the principal purpose of his peer group was to discuss forward-looking issues relating to implementation of the EPA's CCR Rule and related post-CCR Rule regulations at the state level. He also acknowledged that in response to a discovery request submitted by the AGO, he had not been able to provide any significant substantive information he had learned from his peer group about historical coal ash management practices. See Tr. Vol. 15, pp. 70-75; Kerin Direct AGO Cross Ex. 9 (Ex. Vol. 16, Part 3, pp. 309-311).

Witness Kerin's knowledge of matters dating before 2014 was so deficient that at the close of cross-examination, counsel for the Attorney General moved to strike his testimony concerning industry standards and practices and the Company's own policies and practices concerning the management of coal was wastes prior to 2014. Tr. Vol. 15, pp. 76-78. The motion was denied as having been made untimely pursuant to Commission Rule 1-21(c). The motion was in fact timely made, being one which the cited rule recognizes as arising in the course of the hearing to which it relates and, therefore, exempt from the ten-day prior notice requirement. I suppose that in defense of the ruling it could be argued that the motion was actually a "dispositive" motion and therefore subject to the ten-day prior notice requirement, since excluding witness Kerin's testimony would have deprived the Company of its only witness supporting the Company's *prima facie* case on issues going to the prudence and reasonableness of the Company's management of coal ash wastes prior to 2014.

associated with the handling of coal ash wastes prior to 2014.[6] This is a matter that takes on some significance for reasons to be discussed later in Section I.C. of this dissenting opinion. Finally, Company witness Wright's testimony consisted very largely of inadmissible legal opinions concerning his interpretation of provisions of Chapter 62 of the North Carolina General Statutes, and his conclusions as to whether the legal standards therein were satisfied in this case.[7] E.g., State v. Weeks, 322 N.C. 152, 164-65, 367 S.E.2d 895, 903 (1988); State v. Ledford, 315 N.C. 599, 340 S.E.2d 309 (1986).

As already noted, the evidence presented by the Public Staff and several of the intervenors was considerably more detailed and informative in providing an understanding of the evolution of industry standards and practices relating to waste coal ash. But, as was the case in the DEP Rate Case, significant gaps opened when it came time to show how the Company's responses to those evolving standards and practices translated into excessive or avoidable costs for which recovery in this rate case should be disallowed. The presentations by most of the intervenors, and the responses and replies by the Company, centered very largely on subsidiary issues: whether exceedances of North Carolina's 2L groundwater protection standards[8] (2L Rules) are "violations of law" and thus are evidence of imprudence, whether the allowance or creation of unpermitted seeps from ash impoundments is evidence of imprudence or is instead part of the natural order of things, whether the continued use of unlined surface impoundments into the current decade was or was not imprudent, whether delays in instituting comprehensive and continuing groundwater monitoring programs at all plants was or was not imprudent, and so on. With the exception of the Public Staff the parties objecting to the Company's requested rate increase made less effort to connect these subsidiary issues to the ultimate question the Commission must decide, which I summarize as follows: did the Company mismanage its waste ash storage and disposal facilities, either generally over a period of years, or else in discrete instances, in ways that unreasonably caused it to incur costs today that it could have avoided, or that caused an unreasonable increase in the level of costs for tasks that it would have to undertake in any event? Put differently, how much, if at all, have the costs of closure of the waste coal ash facilities been increased by the Company's acts or omissions addressed in one or more of these subsidiary issues? Here, the evidence and arguments of the parties have, in my judgment, been less helpful to the Commission than I would have wished. In the

[6] As an example of this omission, I point to Fountain Direct AGO Cross Ex. 6, a document titled "Ash Basin Closure Update," dated January 13, 2014. Tr. Vol. 9, p. 100-103; Ex. Vol. 10, pp. 609-694. That document included information concerning the Company's accumulated reserves for decommissioning expenses of its coal-fired steam plants and contained some discussion about options for using these reserves to offset the costs of ash basin closures. Although his name appeared on the title page as one of the authors of the document, Company witness Fountain was unable to answer questions about this information. Later witnesses, including Company witness Doss, and the Company's third-party witnesses Spanos and Kopp, who testified concerning depreciation and decommissioning costs, were likewise unable to answer questions attempting to explore the information contained in this exhibit.

[7] See, e.g., Tr. Vol. 26, pp. 157-230.

[8] N.C. Gen. Stat. § 143-211 et seq.; 15 N.C.A.C. .02L .0101 et seq.

following discussion I have tried to undertake answering that question in a manner that is supported by the available evidence.

B. <u>Specific Disallowances of Requested Cost Recovery</u>

I address first the Public Staff's proposals for specific cost disallowances, which the Public Staff does attempt to link to discrete acts or omissions by the Company that are alleged to have been imprudent or unreasonable. With respect to most of those proposals, I concur in the results reached by the majority. While I disagree with the narrow reading of the <u>Glendale Water</u>[9] case that appears to be espoused by the majority, I agree that on the specific facts of this case, the Public Staff's proposed disallowance of legal expenses in the amount of $2,109,406 is not warranted under my own reading of <u>Glendale Water</u>. I leave my disagreement about interpretation of that case for another time when it may make a difference to the outcome. For the reasons set forth by the majority, I agree that (a) the Public Staff's proposed disallowance of groundwater extraction and treatment costs at Belews Creek, (b) the Public Staff's proposed disallowance of costs for equipment purchased to treat and remove selenium from waste ash at the Riverbend Plant, (c) the Public Staff's proposed disallowance of costs incurred for temporary and short-term transport of ash wastes from the Riverbend Plant for offsite disposal in Homer, Georgia, and (d) the Public Staff's proposed disallowance of costs arising from the selection of the Buck Steam Station as a beneficiation site under CAMA[10] should not be accepted, and these costs should instead be allowed as requested by the Company, subject to the general adjustment arising from matters discussed in Section I.C. hereafter.[11]

In the following Sections 1.B.(i)-(ii), I discuss my differences with the majority with respect to two items for which the Company seeks recovery of expenditures made in 2015, 2016, and 2017. In each case, I conclude that the greater weight of the evidence shows that the Company did not act in a reasonable and prudent manner. Instead, the Company elected to pursue higher cost closure activities when, based on what was known at that time, reasonable lower cost alternatives were still available. In addition, I find that these costs were incurred in direct consequence of the Company's admitted imprudence and mismanagement of its waste ash impoundments at Dan River Steam Station (Dan River Plant) and that, but for the release of waste ash into the Dan River in February, 2014, such costs could or would have been avoided.[12] Finally, in Section I.C.,

[9] <u>State ex rel. Utilities Comm'n v. Public Staff</u>, 317 N.C. 26, 343 S.E.2d 898 (1986).

[10] S.L. 2014-122.

[11] I also agree with the Commission's majority decision to disallow $1,606,185 for costs incurred to provide temporary bottled water supplies to customers, as far as it goes. However, I believe that decision should also have included the additional $1,862,898 spent by the Company through August, 2017, to provide *permanent* alternative drinking water supplies to customers in the vicinity of some of its coal-fired plants.

[12] For present purposes, I find that the Company's guilty plea to Counts One through Four (Dan River Plant) and Count One (Riverbend Plant) of the federal criminal indictment, supported by the Joint Factual Statement, sufficiently establishes that the Company was imprudent and negligent in its

I conclude that the Company has imprudently managed cost recovery for known and measurable anticipated costs for coal ash basin closures in the period prior to the present general rate case. This is an issue not adequately addressed by the majority.

(i) W.S. Lee Steam Station – Inactive Ash Basin and "Borrow Area"

The W.S. Lee Steam Station (Lee Plant) in Anderson County, South Carolina, commenced commercial operations in 1951 and was officially retired as a coal-fired plant in November 2014. Kerin Direct Ex. 4 (Ex. Vol. 16, Part 1, p. 9). Two of the three existing coal units were fully retired; the other was converted to natural gas. The Company's plans for decommissioning and closure of the coal-fired units and the associated waste ash surface impoundments were part of a more comprehensive generating fleet modernization program, which is described in detail in the Company's 2012 Plant Retirement Comprehensive Program Plan. See Doss AGO Cross Ex. 1 (Ex. Vol. 12, pp. 818-839). Under that plan, retired coal-burning units were to be decommissioned and demolished to grade level, and ash ponds were to be closed using a cap-in-place strategy, with long-term monitoring thereafter.

During the period prior to retirement of the coal units, there were four waste ash storage or disposal areas at the Lee Plant. The oldest was a surface impoundment originally constructed in 1951. This impoundment was closed and a new, larger impoundment was constructed on top of the closed basin in 1959. The second impoundment was in use until 1977, when a third impoundment was constructed. The two original impoundments are sometimes referred to in the record as the "inactive ash basin," and other times as the "1951/1959 basins." E.g., DEC's Late-Filed Exhibits in Response to Commission's Request for Closure Plans (March 28, 2018). When use of the 1951/1959 basin was discontinued, the impoundments were dewatered and a soil cover was placed over the ash remaining in them. See Kerin Direct Public Staff Cross Ex. 4 (Ex. Vol. 16, Part 1, pp. 73-110); Kerin Rebuttal Public Staff Cross Ex. 4 (Ex. Vol. 24, Part 2, pp. 171-185). The new impoundment opened in 1977 was subdivided into "primary" and "secondary" sections. Only these two components were actively receiving and storing ash waste when the coal-fired generating units at the Lee Plant were retired in 2014. In addition to the two active impoundments and the inactive ash basin, there was an area to the north of the inactive ash basin, sometimes referred to as the "ash fill area," and other times referred to as the "borrow area." Id. This area contained ash that had been excavated from the impoundments and dry stacked. Both the inactive ash basin

management of the ash impoundments at the Dan River Plant. Kerin Sierra Club Cross Exs. 6-7 (Ex. Vol. 16, Part 1, pp. 401-457). As the Company's counsel acknowledged to the Court, the violations of the Clean Water Act to which the Company pleaded guilty were essentially "negligence-based crimes." Ex. Vol. 16, Part 3, p. 235, Lines 11-12. In the present circumstances, the standards for imprudence and negligence are essentially alike. See, e.g., Hempling, Regulating Public Utility Performance, p. 237 (ABA, 2013); Arizona Pub. Serv. Corp., 21 FERC ¶63,007, p. 65,103 (1982), aff'd in relevant part, 23 FERC ¶61,419 (1983); Appeal of Conservation Law Foundation, Inc., 507 A.2d 652, 673 (N.H. 1986) (describing the prudence standard as "essentially applying an analogue of the common law negligence standard").

and the ash fill area were located on that portion of the plant site bordering the Saluda River.[13]

On April 1, 2014, in the wake of the ash release into the Dan River, Company representatives met with the South Carolina Department of Health and Environmental Control (DHEC) to discuss the status of the inactive ash basin. Interest in the inactive ash basin centered on the fact that there was a 60-inch diameter corrugated metal pipe under the inactive ash basin that had been constructed before 1951 and had been used to carry stormwater runoff from the plant site to the Saluda River, a design that was similar to the corrugated metal piping construction that had failed under the ash impoundment at the Dan River Plant. In addition to this pipe, there were two smaller pipes that had conveyed discharge water from the 1951/1959 basins to the river. None of these three pipes was in use in 2014. In the days before the April 1, 2014 meeting with DHEC, the Company had inspected the three pipes and had found no evidence of any flow in them, or any discharges from them.[14] In a letter to DHEC on April 4, 2014, following the earlier meeting, the Company advised that it planned to grout and seal the three pipes and anticipated submitting plans for this work by April 28, 2014. See Kerin Public Staff Cross Ex. 4 (Ex. Vol. 16, Part 1, p. 76). It is evident that the recent Dan River ash release was much on the minds of the Company and DHEC at this time. The Company's letter stated:

> Unlike the basin at Dan River, there has not been standing water in this inactive basin for many years. The pipes are not discharging to the river, and the risk of a potential release to the Saluda River is low since little water exists in the basin.

Id.

On May 1, 2014, the Company again wrote to DHEC to provide an update and a proposed schedule for permanently plugging the three pipes. Id. at 85-86. Again, on May 8, 2014, the Company wrote to DHEC to advise on the progress of its third-party engineering contractor, Soil & Materials Engineers, Inc., and to discuss in more detail its plans for plugging the 18-inch diameter discharge pipe for the 1959 basin.[15] Id. at 91-92. The Company reported that video inspections had disclosed no evidence of water seeping into or otherwise infiltrating the piping. Further letter reports were made to DHEC

[13] A site diagram and brief explanatory history of these ash disposal areas is contained in Kerin Public Staff Cross Ex. 4 (Ex. Vol. 16, Part 1, pp. 73-110). The summary here largely is based on that exhibit.

[14] During the course of the plea hearing in the Company's criminal case, Company counsel acknowledged that the Dan River ash release had prompted the Company to conduct inspections of all of its concrete and corrugated metal pipes at its various waste ash storage and disposal facilities. Kerin Direct AGO Cross Ex. 7, p. 72 (Ex. Vol. 16, Part 3, p. 246.)

[15] In connection with plugging the discharge pipes for the 1959 basin, the Company also planned to raise the level of the basin dike to provide additional assurance that stormwater runoff that might collect in the basin during a heavy rain event would not overtop the dike after the discharge pipes had been sealed, causing erosion of the dike.