BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1146

In the Matter of		
Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	)))))	TESTIMONY OF MICHAEL C. MANESS PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1146

TESTIMONY OF MICHAEL C. MANESS
ON BEHALF OF THE PUBLIC STAFF
NORTH CAROLINA UTILITIES COMMISSION

JANUARY 23, 2018

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND PRESENT POSITION.

A. My name is Michael C. Maness. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am Director of the Accounting Division of the Public Staff – North Carolina Utilities Commission (Public Staff).

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.

A. My qualifications and duties are included in Appendix A.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present certain accounting and ratemaking adjustments that I am recommending be adopted by the North Carolina Utilities Commission (Commission) for purposes of determining the revenue requirement to be approved for Duke

Energy Carolinas, LLC (DEC or the Company), in this proceeding. I am also taking adjustments recommended in certain areas by other members of the Public Staff and flowing them through my schedules so that they can be incorporated into the Public Staff's recommended revenue requirement.

Q. HOW ARE YOUR RECOMMENDED ADJUSTMENTS, AS WELL AS THOSE YOU ARE FLOWING THROUGH, BEING INCORPORATED INTO THE PUBLIC STAFF'S RECOMMENDED REVENUE REQUIREMENT?

A. I have provided the aggregate impact of all the adjustments I am recommending to Public Staff witness Michelle M. Boswell for inclusion in her Exhibit 1, in which she calculates the overall change in the Company's revenue requirement recommended by the Public Staff, which is then used to determine the recommended rate change.

Q. IN WHAT AREAS ARE YOU RECOMMENDING ADJUSTMENTS OR INCORPORATING ADJUSTMENTS RECOMMENDED BY OTHER MEMBERS OF THE PUBLIC STAFF?

A. I am recommending or incorporating adjustments in the following areas:

1. The ratemaking treatment of the costs of DEC's coal ash compliance and cleanup activities;
2. In conjunction with Public Staff witness Tommy C. Williamson, Jr., DEC's proposal to implement a Grid Reliability and Resiliency (GRR) Rider;
3. The level of Allowance for Funds Used During Construction (AFUDC) costs to be included in the base for amortization of the abandoned Lee Nuclear Project's project development costs; and
4. The appropriate remaining useful life to be used for the meters that DEC plans to retire as part of its expedited installation of advanced metering infrastructure (AMI) meters.

I also discuss and provide support for Public Staff witness John R. Hinton's recommended adjustment to nuclear decommissioning expense.

COSTS OF DEC'S COAL ASH MANAGEMENT ACTIVITIES

Q. PLEASE BRIEFLY DESCRIBE THE BACKGROUND OF DEC'S COAL ASH MANAGEMENT ACTIVITIES.

A. The background related to these activities is described in detail in the testimony of Public Staff witness Junis. Briefly, however, DEC's coal ash (also called coal combustion residuals, or CCRs) management activities are being conducted in large part pursuant to the Environmental Protection Agency's (EPA) Coal Combustion

Residual (CCR) rule, finalized in 2015, and North Carolina's 2014 Coal Ash Management Act (CAMA) (along with related statutes passed by the North Carolina General Assembly in 2015 and 2016). Additionally, coal ash management costs are affected by compliance requirements, and non-compliance consequences, related to water quality and dam safety regulations.

Q. IN GENERAL, WHAT ADJUSTMENTS HAVE YOU MADE TO THE COMPANY'S COSTS OF COAL ASH MANAGEMENT?

A. I have made the following adjustments:

1. Adjustments to the coal ash management expenditures to reach a prudent and reasonable level of coal ash expenditures (at least provisionally), as recommended by Public Staff witnesses Vance F. Moore, L. Bernard Garrett, and Charles Junis;

2. Adjustments to the N.C. retail jurisdictional allocation factors to (a) 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 jurisdiction; and (b) allocate all coal ash expenditures by the energy allocation factor, rather than the demand-related production plant allocation factor;

3. Addition of a return on deferred coal ash expenditures from December 2017 through April 2018, to bring the total balance up to the expected effective date of the rates approved in this proceeding;

4. Calculation of the return between January 1, 2015, and March 31, 2018, using a mid-month cash flow convention, rather than the beginning-of-month convention used by the Company;

5. Amortization of the balance of deferred coal ash expenditures at the beginning of May 2018 over a 27-year period, rather than the 5-year period proposed by the Company;

6. Reversal of the Company's inclusion of the unamortized balance of coal ash expenditures in rate base; this reversal, in conjunction with the 27-year amortization period, produces a reasonable sharing of the burden of coal ash expenditures between the Company's ratepayers and its shareholders; and

7. Removal of the ongoing annual expense amount, or "run rate," proposed by DEC to recover additional coal ash management costs incurred from the date the rates approved in this proceeding become effective through the date rates become effective in DEC's next general rate case.

Q. CAN YOU EXPLAIN WHY THERE IS A DEFERRED BALANCE OF COAL ASH MANAGEMENT EXPENDITURES THAT DEC IS PROPOSING TO AMORTIZE FOR RATE RECOVERY BEGINNING WITH THIS PROCEEDING?

A. Yes. On December 21, 2015, Duke Energy Corporation (Duke Energy) filed a letter with the Commission indicating that DEC had established a regulatory asset account for purposes of accounting for costs related to its coal ash-related Asset Retirement Obligations (AROs). Subsequently, on December 30, 2016, in Docket Nos. E-2, Sub 1103, and E-7, Sub 1110, DEC and Duke Energy Progress, LLC (DEP), jointly filed a petition requesting that the Commission authorize each utility to defer certain costs related to compliance with state and federal environmental requirements associated with coal combustion residuals. On January 6, 2017, the Commission issued an order requesting comments on DEC's and DEP's petition.

Several parties, including the Public Staff, filed comments in response to the Commission's order. In its comments, filed on March 15, 2017, the Public Staff stated that in this particular case, it believed that the non-capital costs and depreciation expense related to compliance with state and federal requirements cited in the Companies' petition generally satisfied the criteria for deferral for regulatory accounting purposes, subject to (a) the normal provision that this decision would be entered without prejudice to the right of any party to take issue with the amount, if any, of the deferred costs to be allowed for ratemaking purposes, if such costs are included in future rate filings; (b) recognition of the fact that given the complex task of determining what portion, if any, of these very unique deferred expenses should ultimately be approved for rate recovery in a general rate proceeding, any assumptions regarding such rate recovery should be especially discouraged; (c) the possibility that given the unusual circumstances of these costs, the Commission might determine that some sharing of the costs between ratepayers and shareholders is necessary to ensure that rates charged to customers are limited to an appropriate and reasonable amount; and (d) the determination of the method and length of amortization of any deferred costs.

In addition to not objecting to deferral of these expenses, the Public Staff indicated that the unique nature of the costs and the complexity of the issues surrounding the determination of ultimate rate recovery justified a limited delay in determining the beginning date of any amortization of the deferred expenses until the next respective general rate proceeding, which was expected to be filed sometime in 2017.

With regard to the deferral of a return on capitalized items, as well as deferral of carrying charges on the deferred expenses themselves, the Public Staff did not object to such a deferral. However, the comments indicated that the ultimate recoverability of those deferred returns in rates should be considered to be subject to the provisions generally set forth therein.

The Public Staff also identified several items unique to the topic of coal ash management that would need to be considered as part of the process of determining the appropriate amount of CCR costs that should be recovered from ratepayers, as well as the timing of that recovery. Those items included, but were not limited to, the prudence and reasonableness of the costs incurred; any fines, penalties, or other costs of resolving and/or remediating violations of law and regulations; any costs of settling legal disputes, or of resolving and/or remediating issues as part of a settlement; issues of jurisdictional allocation; whether the setting of fair and reasonable rates demands a sharing of costs between ratepayers and shareholders; and the appropriate and reasonable amortization period for any costs ultimately determined to be prudently incurred and reasonable for recovery from the ratepayers.

On April 19, 2017, DEC and DEP filed reply comments in the subdockets. On July 10, 2017, the Commission issued an order consolidating Docket No. E-7, Sub 1110 with this general rate case proceeding.

Q. DOES THE PUBLIC STAFF CONTINUE TO SUPPORT THE DEFERRAL OF THE COMPANY'S COAL ASH EXPENDITURES AS REASONABLE?

A. Yes. Based on the magnitude and unique nature of the costs, as well as the other reasons set forth in its Sub 1110 comments, the Public Staff continues to believe that prudently incurred coal ash expenditures should be allowed to be deferred for regulatory accounting purposes. However, in order to determine the amount of expenditures that should be recovered from the ratepayers, and the appropriate and reasonable method and timing of that recovery, several of the issues mentioned in the Public Staff's comments must first be addressed. The testimonies filed in this proceeding by Public Staff witnesses Moore, Garrett, Lucas, Junis, and myself address these issues, resulting in the Public Staff's recommended provisional cost recovery for coal ash expenditures prudently incurred from January 2015 through November 2017.

Q. WHY DO YOU USE THE TERM PROVISIONAL?

A. I use this term because there are certain expenditures incurred during the period for which the appropriateness of recovery, in the opinion of the Public Staff, may depend on the outcome of legal proceedings or other legal determinations. These categories of expenditures are described in the testimony of witness Junis. Consequently, the Public Staff believes that determination of the ultimate amount of 2015-2017 expenditures appropriate and reasonable for recovery should await the outcome of these legal situations and further Commission scrutiny of them. Should any of these expenditures be found to be imprudently incurred or otherwise unreasonable or inappropriate for recovery, the Public Staff will propose an appropriate adjustment in DEC's next general rate case.

Q. ARE THERE CERTAIN RATEMAKING APPROACHES TAKEN IN THIS PROCEEDING WITH WHICH YOU AGREE, GIVEN THE PUBLIC STAFF'S COMMENTS IN SUB 1110?

A. Yes. Consistent with its comments, the Public Staff does not object for purposes of this proceeding to the deferral of a return for the period January 2015 through April 2018 on likewise deferred prudent coal ash expenditures. Additionally, due to the magnitude and very unique nature of these costs, the Public Staff does not object to the beginning of the amortization being delayed until the effective date of the rates approved in this proceeding.[1]

Q. PLEASE DISCUSS YOUR ADJUSTMENTS TO THE COMPANY'S RECOMMENDED LEVEL OF DEFERRED COAL ASH MANAGEMENT EXPENDITURES.

A. The first adjustment I am making is to reduce the coal ash management costs subject to deferral, based on the recommendations of Public Staff witnesses Moore, Garrett, and Junis. The rationales for these adjustments are fully set forth in the testimonies of those witnesses, but they can be briefly described as follows:

1. Adjustments recommended by witness Moore with regard to the prudence and reasonableness of coal ash costs incurred for the Cliffside, Buck, Dan River, and Riverbend plants – approximately $72.4 million, on a system basis;
2. Adjustments recommended by witness Garrett with regard to coal ash costs incurred for the W.S. Lee plant - approximately $27.3 million, on a system basis;
3. Adjustments recommended by witness Junis to remove the costs of extraction and treatment of groundwater at the Belews Creek plant – approximately $1.3 million, on a system basis; and

[1] For many types of deferred costs, the Public Staff typically recommends that amortization begin in the month of or the month following the incurrence of the costs.

4. Adjustments recommended by witness Junis to remove the costs of selenium removal equipment at the Riverbend plant - approximately $0.9 million, on a system basis.

I have accumulated these costs and spread them in a reasonable manner throughout the January 2015 through November 2017 period, pursuant to guidance received from the applicable witnesses. This accumulation is set forth on Maness Exhibit 1, Schedule 1-2. The adjustments have then been used to reduce the monthly deferral of system-level costs set forth on Maness Exhibit 1, Schedule 1-1.

Q. PLEASE DESCRIBE YOUR ADJUSTMENTS TO THE JURISDICTIONAL ALLOCATION FACTORS USED TO ALLOCATE SYSTEM COAL ASH COSTS TO NORTH CAROLINA (N.C.) RETAIL OPERATIONS.

A. The first adjustment I have made to the allocation factors is to remove the distinction between those costs the Company describes as “CAMA Only” and the remainder of the coal ash costs. In her testimony, Company witness McManeus states that there is a small portion of coal ash management costs that is “specific to CAMA, unique to North Carolina and appropriate for direct assignment to North Carolina”; Company witness Kerin states that these costs include groundwater wells used specifically for CAMA purposes and permanent water supplies provided to North Carolina customers pursuant to North Carolina law. Consequently, the Company has utilized N.C. retail allocation factors for its self-described CAMA Only costs that do not allocate any of the system level costs to South Carolina operations. However, the Public Staff believes that even though some of the costs incurred by DEC are being incurred pursuant to North Carolina law, it is still fair and reasonable to allocate those costs to the entire DEC system, because the coal plants associated with the costs are being, or were, operated to serve the entire DEC system. The costs are inherently related to the burning of coal to provide electricity to the entire DEC system, including South Carolina. The fact that these particular costs are associated with plants that are geographically located in North Carolina is no more relevant with regard to the proper allocation of these costs than it is to the proper allocation of other costs, such as fuel expense and other variable operations and maintenance expenses, which are allocated to the entire DEC system, because the electricity produced by incurring those costs is transmitted and distributed throughout the entire system.

My second adjustment to the N.C. retail allocation factors is to use 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. I recommend this change because the coal ash costs 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. Therefore, I believe that the energy allocation factor should be used to determine the North Carolina retail portion of these costs.

Q. HAVE COSTS ASSOCIATED WITH ENERGY-PRODUCING ACTIVITIES AND MATERIALS ALWAYS BEEN ALLOCATED BY THE ENERGY ALLOCATION FACTOR?

A. No, not necessarily. There have undoubtedly been a mixture of allocation approaches used for costs associated with fuel expense and other expenses over the years, with fuel and other energy-related costs following an energy allocation approach, while other costs (including certain spent fuel costs and costs associated with end-of-life plant costs) have been allocated consistent with the allocation of production plant (which has historically sometimes been based on peak demand and sometimes based on some type of average of energy and peak demand). However, given the unusual and extraordinarily large nature of the coal ash cleanup costs currently being incurred by the Company, I believe it is most appropriate to consider them in isolation from other costs related to electricity production at a generating plant. Coal ash cleanup costs are directly related to coal ash itself, which is a residual of the burning of coal, a clearly energy-related event. Additionally, it is worth noting that in general, the more coal that was burnt, the more coal ash there is left to deal with, and the more cost that needs to be incurred. Therefore, I believe that it is appropriate and reasonable to allocate those costs by the energy allocation factor.

These allocation factor adjustments are reflected in the deferral balance calculated on Maness Exhibit 1, Schedule 1-1.

Q. WHY HAVE YOU ADDED A RETURN FOR THE PERIOD DECEMBER 2017 THROUGH APRIL 2018 TO THE DEFERRED BALANCE OF COAL ASH COSTS?

A. The Company has updated its proposed balance of deferred coal ash management costs, with an accrued return, through November 2017. However, the rates in this proceeding are not expected to go into effect until May 1, 2018. Therefore, in order to capture all of the costs, including return, related to the January 2015 – November 2017 underlying coal ash costs, it is reasonable to add the return accumulated on the principal amount through April 2018. By doing so, the costs related to that principal amount can be isolated for ratemaking treatment from coal ash costs incurred after November 2017 and any allowed return on those costs. This adjustment is set forth on Maness Exhibit 1, Schedule 1-1.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO CHANGE THE METHOD OF ACCRUING THE RETURN ON DEFERRED COAL ASH COSTS FROM ONE EMPLOYING A BEGINNING-OF-MONTH CASH FLOW ASSUMPTION TO ONE EMPLOYING A MID-MONTH CASH FLOW ASSUMPTION.

A. The Company has used a return calculation methodology that accrues a return for each month assuming that all cash flows during the month occur at the very beginning of the month. I believe this assumption to be unrealistic. I have made an adjustment, on Maness Exhibit 1, Schedule 1-1, to use a mid-month cash flow assumption, which basically assumes that the cash flows in each month are experienced throughout the month, rather than at the beginning.

Q. PLEASE EXPLAIN YOUR FOURTH AND FIFTH ADJUSTMENTS, THE RECOMMENDATION TO AMORTIZE THE DEFERRED BALANCE OF JANUARY 2015 THROUGH NOVEMBER 2017 COAL ASH COSTS OVER 27 YEARS, AND THE RECOMMENDATION TO REVERSE THE COMPANY'S INCLUSION OF THE UNAMORTIZED COSTS IN RATE BASE.

A. The Company has recommended that the costs of coal ash management be amortized over five years for ratemaking purposes in this proceeding. In my opinion, that is simply too short an amortization period for costs of the magnitude and nature of these. Instead, the Public Staff has been guided in its choice of amortization period for these costs in this proceeding by its belief that it is most reasonable and appropriate for coal ash costs, after specific imprudently incurred or otherwise unreasonable amounts have been discovered and disallowed for recovery, to be shared equitably between the ratepayers and the Company's shareholders.

Q. WHY DOES THE PUBLIC STAFF BELIEVE COAL ASH COSTS, AFTER REMOVAL OF SPECIFICALLY DISALLOWABLE AMOUNTS, SHOULD BE SHARED BETWEEN THE RATEPAYERS AND SHAREHOLDERS?

A. There are two general reasons why the sharing of costs for coal ash management is reasonable and appropriate for ratemaking purposes. First, as discussed in more detail by Public Staff witness Junis, the extent of the Company's failure to prevent environmental contamination from its coal ash impoundments, in violation of state and federal laws, supports ratemaking that leaves a large share of the costs for DEC shareholders to pay.

Second, there is a history of approval for sharing of extremely large costs that do not result in any new generation of electricity for customers. Such sharing between ratepayers and shareholders has been approved for costs of abandoned nuclear construction and for environmental cleanup of manufactured gas plant facilities. Even if the reasons for equitable sharing set forth by Mr. Junis were not present, the Public Staff still believes that some level of sharing, perhaps comparable to that previously used for abandonment losses on cancelled nuclear generation facilities, would be appropriate and reasonable for DEC's coal ash costs.

Q. HOW DOES THE PUBLIC STAFF ACHIEVE THIS RECOMMENDED SHARING?

A. The first step in achieving a sharing is to exclude the unamortized amount of the deferred expenses from rate base. As a result of taking this step, the Company will not be allowed to earn a return from the ratepayers on the unamortized balance while the deferred costs are being amortized. The second step is to choose an amortization period that will result in a reasonable and appropriate sharing of the costs.

Q. IS EXCLUDING DEFERRED EXPENSES OR LOSSES FROM RATE BASE LEGAL UNDER THE NORTH CAROLINA GENERAL STATUTES?

A. Yes, according to advice of counsel. Pursuant to G.S. 62-133(b)(1), the only costs that the Commission is required to include in rate base are (1) 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 …", and (2) in some circumstances, the costs of construction work in progress. I am advised by counsel that beyond those requirements, what is and what is not allowed in rate base is within the legal discretion of the Commission to decide, as long as the rates set thereby are fair and reasonable to both the utility and the consumers. Moreover, G.S. 62-133(d) requires the Commission to "consider all other material facts of record that will enable it to determine what are reasonable and just rates."

The Commission has taken this approach several times in past cases, most often in the cases of nuclear and coal plants abandoned prior to commencing commercial operation, including, specifically for DEC, the abandonment loss related to the Cherokee Plant (Units 1, 2, and 3). In DEC's 1983 general rate case, Docket No. E-7, Sub 358, the Commission outlined its policy regarding the treatment of plant abandonment losses:

> The proper ratemaking treatment of abandonment losses related to electric generating plants has been before the Commission in several cases and will continue to arise in future cases. The Commission has, therefore, undertaken to reexamine this important

> issue in order to develop a more consistent and equitable approach to it. The Commission's ultimate responsibility with respect to ratemaking is to fix rates for the service provided which are fair and reasonable both to the utility and to the consumer. G.S. 62-133(a); State ex rel. Utilities Commission v. Morgan, 277 N.C. 255, 177 S.E. 2d 405 (1970); State ex rel. Utilities Commission v. Area Development, Inc., 257 N.C. 560, 126 S.E. 2d 325 (1962).
>
> Although the parties to this proceeding may disagree as to the proper amortization period, they generally agree that the Company should be allowed to recover the prudently invested cost of its abandonment losses through amortization over some period of time. The Commission, based upon the evidence presented, must determine what is a fair amortization period in order to fairly allocate the loss between the utility and the consumer. With regard to the Cherokee Units 1, 2, and 3, the Commission concludes that utilization of a 10-year amortization period is proper and fair in this proceeding for the reason that such an amortization period, particularly when considered in conjunction with the Commission's decision, as subsequently discussed, to allow Duke no return on the unamortized balance, will service to more reasonably and equitably share the burden of such plant cancellations between the Company's shareholders and its present and future ratepayers.
>
> Furthermore, the Commission has determined that it is neither fair nor reasonable to include any portion of the unamortized balance of the prudently incurred abandonment losses associated with the Cherokee units in rate base and that no adjustment should be allowed which would in fact have the effect of allowing the Company to earn a return on the unamortized balance. The Commission has concluded that this treatment provides the most equitable allocation of the loss between the utility and the consumer.

Seventy-Third Report of the North Carolina Utilities Commission, pp. 255 ff.

This specific issue has also come before the North Carolina courts. As discussed in the legal memorandum from counsel, attached as Maness Appendix B, in 1989, the North Carolina Supreme Court affirmed the Commission's decision that reasonable rates can include a sharing between ratepayers and investors with regard to plant cancellation costs. In <u>State ex rel. Utilities Com. v. Thornburg</u>, 325 N.C. 463 (1989), the Attorney General had sought exclusion of all abandonment costs related to the Harris Nuclear Plant. However, the Commission allowed amortization of the abandonment costs, with no return on the unamortized balance. The Court ruled that the Commission was acting within its discretion:

> [T]he Commission's order does not err as a matter of law in authorizing CP&L to continue to recover a portion of the cancellation costs of the abandoned Harris Plant as operating expenses through amortization. The Commission's determination was supported by several findings and conclusions. First, the Commission found that although "[t]his case must of course be decided on the basis of North Carolina statutes" the "majority of courts and commissions that have dealt with this issue have allowed ratemaking treatment of abandonment losses, usually as operating expenses." Second, the Commission concluded "that a liberal interpretation of the operating expense element of ratemaking so as to include the Harris abandonment losses is appropriate herein." Last, the Commission found further support for its conclusion was provided by N.C.G.S. § 62-133(d), which allows the Commission to consider all material facts in the record in determining rates.
>
> . . . .

> Last, we disagree with the Attorney General's contention "that strong policy considerations support the disallowance of [cancellation] expenses." We note that jurisdictions have generally dealt with the allocation of cancelled plant costs in one of the following three ways:
>
> (1) recovery of all of the costs from ratepayers, by allowing amortization of the investment plus a return on the unamortized balance;
>
> (2) recovery of all costs from shareholders through a total disallowance of recovery in rates, instead requiring the utility to write off the entire amount in a single year; or
>
> (3) recovery from ratepayers and shareholders through amortization of costs in rates over a period of years, with no return on the unamortized balance.
>
> . . . Strong policy considerations support the Commission and commentators who have concluded that method three is the best of the three alternatives in that it promotes "an equitable sharing of the loss between ratepayers and the utility stockholders."
>
> . . . .
>
> On this record, the Commission's continued use of method three is within the Commission's discretion, and this Court will not disturb that decision.

Similarly, an equitable sharing of costs was approved in the Commission's October 7, 1994, Order Granting a Partial Rate Increase in Docket No. G-5, Sub 327. In that case Public Service Company of North Carolina (PSNC) owned several sites that were previously operated as manufactured gas plants (MGPs). The MGPs had ceased operations in the early 1950s. At the time of the rate case, the MGP sites were currently under investigation pursuant to environmental law. In its Order, the Commission concluded that deferral and amortization of MGP clean-up costs in a general rate case, rather than through a tracker, would result in more stable rates than otherwise. Furthermore, the Commission concluded that the unamortized balance of MGP costs should not be included in rate base, resulting in a sharing of clean-up costs between ratepayers and shareholders that would provide PSNC with motivation to minimize its costs.

Q. COMPANY WITNESS WRIGHT STATES IN HIS TESTIMONY THAT THE COAL ASH DISPOSAL COSTS THAT DEC IS SEEKING TO RECOVER IN THIS CASE ARE A "USED AND USEFUL" COST. DO YOU AGREE?

A. No. In North Carolina utility regulation, the term "used and useful" only applies to the public utility's property, not the <u>expenses</u> it incurs in the operation, maintenance, or disposal of that property. Witness Wright seems to argue in his testimony that since the costs deferred for coal ash clean-up are associated with property that is or once was used and useful, the costs themselves should be considered "used and useful," and therefore should be included in rate base, to the extent they remain unamortized, pursuant to G.S. 62-133(b)(1). In my opinion, this argument by witness Wright is incorrect and his is an inappropriate application of the term "used and useful." It is appropriate to state that the actual costs <u>capitalized</u> 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. Instead, they are allowed to be recovered from the ratepayers on an ongoing basis as operating expenses, if they themselves are determined by the Commission to be reasonable and prudently incurred. This recovery is provided for under G.S. 62-133(b)(3), an entirely different portion of the statute. If, however, there are expenses that were incurred in the past, but for some reason the Commission decides that they can be deferred for recovery in the future, the Commission can approve a regulatory asset to capture such expenses, and even provide for a return on them due to the deferral of their recovery (by including them in rate base or otherwise providing for carrying costs). This treatment is within the discretion of the Commission, but it does not transform the Commission-created regulatory asset into capitalized property cost, such as the cost of a generating plant. The two types of costs are fundamentally different from one another; one is the actual cost of property intended to provide service in the present or future; the other is a past expense deferred for future recovery.

Q. IN WHICH CATEGORY DO THE DEFERRED COSTS PROPOSED IN THIS CASE BY DEC FOR AMORTIZATION FALL?

A. I believe that the costs should fall into the category of a deferred expense for the following reasons:

(1) The Company has itself chosen to request 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, with a proposed regulatory asset intended to provide for the recovery of expenses incurred in the past, expenses that but for the Commission's approval of the deferral request, would be immediately written off. Although the Company could have chosen to propose following the method prescribed by generally accepted accounting principles (GAAP) for non-regulated companies, which does provide for the recording of at least a portion of asset retirement costs as a depreciable asset (albeit one that might be offset in rate base by unspent asset retirement obligations), it did not; nor did it propose to follow some other approach, whereby it might specifically identify capital costs separately and include them in rate base, depreciating them over their useful lives, while accounting for

other expenses on an ongoing basis. Instead, the Company has proposed to utilize an accounting and ratemaking model that accounts for and recovers the coal ash cleanup costs as expenses on an "as-spent" or "as-accrued" basis, without specific identification of or accounting for any costs as plant in service or other property. It has chosen a totally different route than the one typically followed for utility property.

(2) The costs proposed for deferral and amortization themselves are not in any manner costs related to present or future operations; instead they are costs that, but for Commission approval of the deferral and amortization, will be immediately written off as expenses related to the past. There may be some form of capital assets underlying some portion of the activities undertaken by DEC to meet its coal ash compliance obligations; however, the particular costs requested for deferral related to such assets, if they exist, are themselves expenses related to past operations. The Company itself stated, in its Petition for Deferral filed on December 30, 2016:

> The Companies are requesting to defer to a regulatory asset, until the effective date of new rates from the next base rate case, all non-capital costs as well as the depreciation expense and cost of capital at the weighted average cost of capital for all capital costs

> related to activities required under the legislative and regulatory mandates … <u>(Petition, page 14)</u>

All of the costs identified in the quote above are expenses related to periods that will be in the past when the rates requested in this case become effective; they are not forward-looking capital costs related to future operations, which are characteristic of the assets recorded as used and useful property and included in rate base.

Q. DOES THE FACT THAT THE COMPANY HAS CLASSIFIED THE PROPOSED COAL ASH DEFERRED COST BALANCE IN ITS FILING AS "WORKING CAPITAL" MEAN THAT THE REGULATORY ASSET MUST BE INCLUDED IN RATE BASE?

A. No, it does not, because in my opinion, this classification is just a matter of convenience. True working capital is the investment made in materials and supplies, cash, and other similar items to finance and provide for the Company's present and future operations; in other words, to "do the work" of providing ongoing utility service. The proposed deferred coal ash compliance costs are expenses incurred in the past that the Company proposes to recover in the future; they have nothing to do with the Company's forward-looking obligation to provide utility service. Normally, it does no harm for the Company to group many disparate items under the heading of working capital;

however, one should not mistake the inclusion of the proposed coal ash cost deferred costs in this group for actual evidence that such costs are in fact "working capital."

In summary, DEC's accrued coal ash management costs may qualify as regulatory assets, but they are not utility plant or another form of utility "property." They may have been prudently incurred expenses in support of utility plant (or former utility plant), but they themselves are not utility plant, nor are they "used and useful" in the sense of G.S. 62-133(b). Contrary to witness Wright's assertions, the Commission is under no obligation to include them in rate base or to otherwise allow a return on them to be recovered or accrued.

Q. PLEASE DESCRIBE HOW THE SECOND STEP YOU DESCRIBED PREVIOUSLY, THE CHOICE OF AN AMORTIZATION PERIOD, CAN BE USED TO ACHIEVE A SHARING OF COSTS BETWEEN THE UTILITY AND ITS RATEPAYERS.

A. Once it has been determined that the unamortized balance of the coal ash costs will not be included in rate base, the ability of the utility to recover those costs at a 100% level becomes entirely dependent upon the speed at which recovery can be achieved. The utility has already spent the money represented by the deferred costs in question; therefore, it will be required to borrow money or use equity to finance the spent costs until it can recover them from the ratepayers. If the utility was able to recover the total cost immediately, it would recover all of the costs at a 100% level; however, the ratepayers would also lose all of the time value of money that could be provided to them by a reasonable amortization period. Another way to look at this is that in that immediate recovery circumstance, the utility recovers 100% of the present value of the deferred costs at the time of deferral, and the ratepayers bear 100% of that cost. However, as the delay in utility recovery (i.e., the amortization period) increases, the utility's financing costs increase, and the burden of the loss of the time value of money on the ratepayers decreases. The utility recovers a lesser amount and lesser percentage of the present value of the underlying cost, and thus the ratepayers bear less of the burden. Considering the voluminous issues surrounding DEC's coal ash management in North Carolina as articulated by Public Staff witness Junis, it is inappropriate to ask ratepayers to bear 100% of the risk or fund a return to shareholders on these expenses.

Q. WHAT AMORTIZATION PERIOD DOES THE PUBLIC STAFF RECOMMEND IN THIS CASE FOR THE COMPANY'S COAL ASH COSTS AS ADJUSTED BY THE PUBLIC STAFF?

A. As shown on Maness Exhibit 1, Schedule 1, the Public Staff recommends an amortization period of 27 years beginning on the date the rates approved in this proceeding become effective.

Q. WHAT SHARING PERCENTAGE DOES A 27-YEAR AMORTIZATION PERIOD PRODUCE?

A. At the net-of-tax overall rate of return recommended by the Public Staff, a 27-year amortization period results in the ratepayers bearing approximately 49% of the present value of the January 2015 – November 2017 deferred costs at May 1, 2018 (with a return accrued to that point). The Public Staff believes that this level of sharing is reasonable and appropriate for the reasons discussed above.

Q. IN THE 2016 DOMINION NORTH CAROLINA POWER (DNCP) RATE CASE, DOCKET NO. E-22, SUB 532, THE PUBLIC STAFF AGREED TO AN AMORTIZATION PERIOD OF FIVE YEARS FOR COAL ASH COSTS, WITH THE UNAMORTIZED BALANCE INCLUDED IN RATE BASE. WHY ARE YOU RECOMMENDING SUCH A DIFFERENT TREATMENT IN THIS CASE?

A. One of the reasons for the different recommendation is sheer magnitude. In the DNCP case, the total paid-to-date system costs in question were only approximately 12% of the total paid-to-date system costs at issue in this case. Additionally, at that point in time, there was no evidence in the record of environmental problems identified as related to DNCP's coal ash facilities. As discussed by Public Staff witness Junis, that is clearly not the case for DEC with respect to its coal ash facilities. Also, DNCP's costs were related to implementation of the federal CCR Rule, whereas DEC was required to implement CAMA, which contained various expedited cleanup provisions that escalated costs, in addition to the federal CCR Rule. I would also like to point out that the stipulation filed by the Company and the Public Staff in that proceeding stated that "Notwithstanding this agreement, the Stipulating Parties further agree that the appropriate amortization period for future CCR expenditures shall be determined on a case-by-case basis." The case does not serve as precedent for regulatory accounting recommendations.

Q. PLEASE DESCRIBE THE PUBLIC STAFF'S RECOMMENDATION WITH REGARD TO THE EXPECTED LEVEL OF ONGOING N.C. RETAIL ANNUAL COAL ASH MANAGEMENT COSTS OF APPROXIMATELY $201 MILLION THAT THE COMPANY PROPOSES TO INCLUDE IN THE REVENUE REQUIREMENT IN THIS CASE.

A. The Public Staff agrees with the Company's proposal for an ongoing regulatory asset/liability to capture unrecovered prudently incurred and reasonable coal ash costs incurred after November 30, 2017, but opposes the establishment of an amount to be recovered on an ongoing basis between this proceeding and the Company's next general rate case. The main reason for the Public Staff's opposition is that it will potentially make future equitable sharing of the costs of coal ash costs much harder to achieve, thus more likely resulting in unjust and unreasonable rates. For example, were the Commission to approve the recovery of 100% of the estimated annual costs on an ongoing basis between this rate case and the next one, a significant adjustment would be necessary in the rate case to "rebalance" the scales to an overall 50% sharing of the costs incurred after November 2017. If there were few unrecovered costs at the time of the next case, the necessary re-balancing might well require that money be flowed back to the ratepayers through future amortization, instead of the Company collecting those unrecovered costs.

From a practical standpoint, this problem could be addressed by only allowing the Company to recover on an ongoing basis the same percentage of costs that the Commission had approved for the ratepayer to bear in this proceeding. However, counsel for the Public Staff has advised me that such an approach has not been reviewed by the courts and might not hold up to legal scrutiny. Therefore, the Public Staff recommends that no ongoing recovery of annual future costs be allowed; instead, such costs should be deferred for consideration of amortization in the Company's next general rate case. This will ensure the Commission retains the necessary tools to ensure customers do not pay for unreasonable and imprudent coal ash management expenses or bear 100% of the risk associated with funds to pay such expenses.

Q. WHAT DOES THE PUBLIC STAFF RECOMMEND WITH REGARD TO THE ACCRUAL OF A RETURN ON THE REGULATORY ASSET CREATED BETWEEN NOW AND THE NEXT RATE CASE FROM THE ACCUMULATION OF POST-NOVEMBER 2017 COAL ASH COSTS?

A. The Public Staff recommends that the accrual of a return between the two rate cases be allowed by the Commission, at the net-of-tax rate of return applied to the balance of the regulatory asset, net of associated accumulated deferred income taxes. At the time of the next general rate case, the Commission can determine the appropriate sharing of the regulatory asset through amortization at that point in time.

Q. DO YOU HAVE ANY FURTHER COMMENTS REGARDING COAL ASH COSTS?

A. Yes. The Public Staff is aware that Duke Energy has filed suit against certain of its insurers to recover coal ash management costs under its policies with those insurers. Duke Energy has stated that if it does recover on any of those claims, that recovery will be credited against coal ash management costs to be recovered from its ratepayers. The Public Staff believes that ratepayers should be credited the full amount of any recovery from those policies and that Duke Energy should vigorously prosecute those lawsuits on behalf of ratepayers.

<u>GRID RELIABILITY AND RESILIENCY (GRR) RIDER</u>

Q. PLEASE DESCRIBE THE PUBLIC STAFF'S POSITION REGARDING THE GRR RIDER.

A. In his testimony, Public Staff witness Williamson presents several reasons why the Public Staff remains concerned regarding DEC's Power/Forward Carolinas (PFC) initiative and its proposed GRR Rider through which the Company would recover its PFC costs. He summarizes his reasoning by stating that the Public Staff is not persuaded that all of the PFC initiative components will result in grid modernization[2] as opposed to normal improvements that DEC

[2] Public Staff witness Tommy C. Williamson, Jr. defines "grid modernization" in his direct testimony filed in this docket as "efforts to bring the current grid up to new standards of operation and reliability…over and above normal and routine application and use."

should continuously undertake; therefore, the Public Staff does not believe that the GRR Rider as proposed by DEC should be approved. In my testimony, I set forth some of the more general regulatory accounting and ratemaking reasons that the Public Staff does not support the GRR Rider.

Q. WHAT ARE THE GENERAL REASONS THAT CAUSE THE PUBLIC STAFF TO OPPOSE ESTABLISHMENT OF A GRR RIDER?

A. First, riders not specifically established by statute, like deferral accounting, are an exception to the general method by which rates are normally set for North Carolina's electric public utilities. Rates are normally set on the basis of the aggregate amount of the utility's expenses, revenues, and rate base, and a consideration of the rate of return produced by that aggregation of costs and revenues. Specific components of revenues and costs fluctuate over time, and increases in one cost component can often be offset by decreases in another, thus perhaps mitigating the need for a rate increase to provide recovery of the increase in cost of the first item. Any time the Commission splits apart one item or a group of items for single-item ratemaking, through either a rider or deferral accounting, it upsets the balance set by the precepts of G.S. 62-133. This is one of the reasons that the Commission has previously stated that deferral accounting should be an exception, not the rule, as exemplified by the following:

> [T]he Commission has historically treated deferral accounting as a tool to be allowed only as an exception to the general rule, and its use has been allowed sparingly.
>
> . . .
>
> The Commission has also been reluctant to allow deferral accounting because it, typically, equates to single-issue ratemaking for the period of deferral, contrary to the well-established, general ratemaking principle that all items of revenue and costs germane to the ratemaking and cost-recovery process should be examined in their totality in determining the appropriateness of the utility's existing rates and charges.
>
> (Order Approving Deferral Accounting with Conditions, E-7 Sub 874 (Mar 31, 2009), page 24)

The Public Staff believes that the GRR Rider would upset that balance in a significant way.

Second, it is important that items set aside for special treatment, such as riders and deferred costs, should be both extraordinary in magnitude and very unique in type.[3] While it is certainly true that DEC intends to expend significant funds in pursuit of its PFC initiative, the Public Staff believes, as indicated by Mr. Williamson, that many of the items proposed by DEC to be included in the GRR

[3] Additionally, as in the case of major generating additions, sometimes deferral accounting is used to "synch up" the date of the commercial operation of the facility with the effective date of a rate change.

Rider are the types of activities in which the Company engages on a routine and continuous basis, with or without the modernization of the grid. As such, these items are neither extraordinary nor unique. DEC has proposed several programs, such as targeted undergrounding, that do not meet the Public Staff's definition of grid modernization. Thus, the PFC is not sufficiently tailored to warrant a rider for expedited cost recovery.

Third, when a rider or deferral accounting is established, costs intended to be included in the rider should preferably be easily identifiable, because of the issues and controversies that might arise over whether specific items of cost are eligible for inclusion. As Mr. Williamson points out in his testimony, the types of plant items that the Company is proposing are somewhat vaguely described; thus it is certainly possible that these types of disputes would regularly arise.

Fourth, because of the nature of specific-item ratemaking, very careful vetting of items proposed to be included in the rider would be necessary on a recurring basis, putting substantial additional strain on Commission and Public Staff resources, as well as the resources of other intervenors. This is particularly true given the short time frames usually established for annual rider proceedings.

Fifth, any time large amounts of recurring types of costs are split off from the regular ratemaking process, incentives restraining capital investment that are naturally present in the normal aggregated method of ratemaking practiced under G.S. 62-133 are relaxed, because the only thing restraining the utility from making these types of investments is the ability of the regulator to devote precious resources to eliminate any imprudent or unreasonably large costs. The Public Staff's investigation time in the various electric rider proceedings is considerably shorter than its investigation time in a general rate case. Furthermore, electric rider proceedings are "stacked" so as to run concurrently, thus further limiting Public Staff human capital resources to undertake a thorough investigation. Gone is any natural restraint imposed by the difficulties in mounting a general rate case proceeding. Adding another rider proceeding, especially one involving extensive capital investments, to the already compressed and time intensive electric rider proceedings would limit the Public Staff's and Commission's ability to thoroughly vet the Company's request.

Sixth, splitting out major items for single-item ratemaking can make it more likely that the Company will exceed its allowed or appropriate overall rate of return. The Public Staff knows from experience that it can be much more difficult to bring a utility in for a rate decrease than it is for a Company to propose and support a rate increase.

For all of these reasons, and given the particular circumstances of the costs proposed for inclusion, the Public Staff recommends that the Commission not approve the GRR Rider.

Q. IF, DESPITE THE PUBLIC STAFF'S RECOMMENDATION, THE COMMISSION DETERMINES IT IS IN THE PUBLIC INTEREST TO APPROVE SOME FORM OF A GRR RIDER IN THIS PROCEEDING, ARE THERE SPECIFIC CRITERIA THAT THE PUBLIC STAFF BELIEVES SHOULD BE INCLUDED IN THE RIDER'S STRUCTURE TO PROTECT RATEPAYERS?

A. Yes. Should the Commission find that establishment of a rider is in the public interest, the Public Staff recommends the following:

1. The rider should be effective for no longer than necessary to complete the PFC initiative, the term of which the Company has identified as 10 years.

2. The Company should only be allowed to recover reasonable and prudently incurred capital costs of projects from the categories below that are extraordinary, discrete, and non-growth related. "Capital costs" means the annual depreciation expense and pretax return on costs permitted to be

capitalized pursuant to the FERC Uniform System of Accounts, net of accumulated depreciation and accumulated deferred income taxes, using the current federal and state income tax rates and DEC's capital structure, cost of long-term debt, and return on equity approved in its most recent general rate case. Programs eligible for possible inclusion in the rider should be limited to the following programs as discussed by the Company in a presentation to the Public Staff on November 9, 2017[4], and discussed further by witness Williamson:

a. Distribution Hardening and Resiliency;

b. Transmission Improvement;

c. Self-Optimizing Grid;

d. Communications Network Upgrades; and

e. Advanced Enterprise System.

3. The rider should be structured similarly to the Water System Improvement Charge (WSIC) and Sewer System Improvement Charge (SSIC) (see Commission Rules R7-39

---

[4] "Power/Forward Carolinas, Executive Technical Overview," Duke Energy Carolinas, LLC, November 2017. Although included as part of Power/Forward Carolinas initiative, the Public Staff does not include the costs associated with AMI meters or targeted undergrounding`.

and R10-26) in which there is a two stage process, as described below:

a. DEC shall file for approval of any PFC-related projects it wishes to have ultimately recovered through the GRR Rider. Any application for approval shall include a description and purpose of the project, an estimate of the time needed to complete the project, an estimate of the capital costs, and an estimate of the ongoing operating and maintenance (O&M) costs and savings resulting from the project. Upon receiving Commission approval of the project, the project will be eligible for cost recovery through the rider.

b. DEC shall file an annual request for PFC cost recovery. Any application shall include a list of eligible projects that had previously been approved AND have been placed into service, the actual costs incurred, and the proposed rates for recovery. The allocation of any costs included in the rider should be consistent with the Company's most recently filed cost of service study.

4. The Company should be permitted to recover only the capital costs of those projects that have previously been approved by the Commission to be included in the rider and are in service. Cumulative revenues from any grid rider for eligible transmission and distribution projects of the Company pursuant to the rider should not exceed two percent (2%) of the total annual electric service revenue requirement approved by the Commission in DEC's most recent general rate case.

5. Upon the filing of a general rate case under G.S. 62-133, any remaining unrecovered capital costs in the rider should be included in the Company's rates and shall no longer be recoverable in the rider.

Q. PLEASE DESCRIBE IN MORE DETAIL THE CRITERIA YOU OUTLINED IN YOUR PREVIOUS ANSWER.

A. "Reasonable and prudently incurred" refers to the well-established regulatory analysis undertaken by the Commission when evaluating all utility investment and expenses. DEC's decision to incur capital costs under its PFC initiative must be prudent and the costs incurred in furtherance of that decision must be reasonable.

"Extraordinary" means projects that are not otherwise included in DEC's ordinary course of business of delivering safe, reliable electric service to customers.

"Discrete" means specifically identifiable eligible projects that are directly required to implement DEC's PFC initiative.

"Non-growth related" means projects that are not required to be undertaken by DEC to provide new or additional electric services due to increased demand and/or customer growth.

"Cost-effective" means that proposed projects should pass a cost-benefit analysis whereby the quantifiable benefits to customers outweigh the costs customers will incur to pay for the project.

"Primarily focused on grid modernization" means efforts to bring the current grid up to new standards of operation and reliability, not investments needed to maintain or restore the grid to historic levels of operation and reliability. Projects recovered through a GRR Rider should only reflect activities and investment over and above normal and routine application and use. To the extent a project provides only indirect or ancillary support to the PFC initiative, those costs should not be recoverable through any GRR rider.

Q. WHAT OTHER PARAMETERS SHOULD THE COMMISSION INCORPORATE INTO ANY GRR RIDER?

A. Any GRR Rider should be time limited and only effective for such period of time necessary to complete the PFC initiative. Upon the filing of a general rate case, all then-current costs flowing through the rider should be rolled into base rates and the rider reset to zero.

Q. SHOULD THE COMMISSION DETERMINE THAT IT IS IN THE PUBLIC INTEREST TO ESTABLISH A GRR RIDER, HOW DO YOU PROPOSE THE COMMISSION ADDRESS CONCERNS THAT THERE IS INSUFFICIENT INFORMATION TO ADDRESS DEC'S PFC INITIATIVE?

A. I have two recommendations. First, the Commission should require DEC to obtain pre-approval for any PFC initiative projects for which it wishes to recover costs through a GRR Rider. This will ensure that all projects are reviewed and vetted consistent with the criteria I outlined above, thus avoiding any after-the-fact disputes over whether a project is appropriate for cost recovery under the PFC initiative. My recommendation draws heavily on the WSIC Mechanism outlined in NCUC Rule R7-39 and the SSIC Mechanism outlined in NCUC Rule R10-26. While I have not been directly involved in evaluating WSIC and SSIC projects, the parameters established by the rules appear to protect customers by ensuring project review and approval within narrow categories, while also providing certainty to the utility with respect to cost recovery.

The application for approval of projects process described in the criteria protects ratepayers by limiting the types of projects that may be recovered through any GRR Rider and more closely ensure customers are receiving the benefits promised by grid modernization. The pre-approval process would protect against expanding the scope and scale of projects, which frequently leads to escalating costs. The process also protects the utility by providing greater assurance of cost recovery for specific projects, provided all costs are reasonable and prudent.

Second, if it approves a GRR Rider, I recommend that the Commission establish reporting requirements for the rider similar to those it has established for similar riders, such as the WSIC/SSIC, the Integrity Management Rider, and the Integrity Management Tracker.

CUT-OFF DATE FOR LEE NUCLEAR PROJECT DEVELOPMENT AFUDC COSTS

Q. PLEASE BRIEFLY DESCRIBE THE PUBLIC STAFF'S REVIEW OF LEE NUCLEAR PROJECT DEVELOPMENT COSTS, AND YOUR SPECIFIC ROLE.

A. Public Staff witness Dustin R. Metz is presenting testimony in this proceeding presenting the results of his findings regarding the cancellation of the W. S. Lee Nuclear project (the Project). Public

Staff witness Boswell presents testimony describing the Public Staff's recommendation of how prudently incurred and reasonable Project development costs should be treated for purposes of rate recovery. My specific role in the investigation of the Project development costs was to investigate the reasonableness of the accrual of AFUDC (the carrying costs, or return) accrued on the project balance during its life, particularly the date that AFUDC accrual began, and the date that the Company has indicated in its filing that it plans to cease accruing AFUDC.

Q. WHAT ARE THE RESULTS OF YOUR REVIEW?

A. Based on my review, I believe that for purposes of this proceeding, the time at which the Company began accruing AFUDC on the Project was reasonable and within the guidance offered in the accounting standards of the Federal Energy Regulation Commission (FERC). However, I do not agree with the proposal by the Company, as reflected in its filing and supplemental filing, to continue accruing AFUDC until the effective date of the rates approved in this proceeding (estimated to be May 1, 2018).

Q. WHY DO YOU DISAGREE WITH THE COMPANY'S PROPOSAL?

A. Based on the Company's testimony and the Public Staff's discussions with Company personnel, it appears that the Company believes that AFUDC should continue until the Commission "allows" the Company to cancel the Project pursuant to G.S. 62-110.7(d). However, while the statute allows AFUDC to be included as a nuclear project development cost, it is my opinion, based on advice of Counsel, that the statute does not mandate that AFUDC continue to be accrued up until cancellation is "allowed." Instead, I believe that the accrual of AFUDC should follow the standards set forth by the FERC, along with any requirements that might be put into place by this Commission. In other words, AFUDC is allowed to be included in project development costs, just like any other appropriately incurred cost; however, just as the Company is not required to continue spending money on "bricks and mortar" until the Commission approves cancellation, neither is the Company required to accrue AFUDC up until the date of the Commission's order allowing cancellation, nor is the Commission required to allow such accrual.

Q. BRIEFLY, WHAT ARE THE FERC STANDARDS REGARDING THE CESSATION OF AFUDC ON AN ABANDONED PROJECT?

A. FERC Accounting Release No. 5 (AR-5) states that "if construction is interrupted or suspended, AFUDC accruals must cease unless the company can justify the interruption as being reasonable under the circumstances."

Q. DO YOU BELIEVE THAT WORK ON THE PROJECT HAS BEEN "INTERRUPTED OR SUSPENDED"?

A. Yes; I believe substantive work on the Project ceased no later than December 31, 2017.

Q. PLEASE EXPLAIN WHY YOU BELIEVE THAT SUBSTANTIVE WORK CEASED BY THE END OF 2017.

A. In his direct testimony filed on August 25, 2017, Company witness Christopher M. Fallon stated, with regard to the Project, that "[n]o project development work continues." However, during further discussions with the Public Staff, Company personnel stated that after that date, certain wrap-up activities continued throughout 2017, including technical and departure reviews. However, the Company has now confirmed to the Public Staff that this work was complete by the end of the year and the Company ceased accruing AFUDC at the end of 2017 in accordance with FERC accounting requirements.

Q. BASED ON THIS INFORMATION, WHAT IS YOUR RECOMMENDATION?

A. I recommend that the estimated 2018 AFUDC of approximately $9 million (N.C. retail) be removed from the calculation of the Project development costs proposed for amortization in this proceeding. I have provided this adjustment to witness Boswell.

Q. DO YOU HAVE ANY FURTHER COMMENTS REGARDING THIS MATTER?

A. Yes. The Public Staff is still awaiting answers to certain follow-up questions asked of Company personnel regarding the wrap-up work. If these responses indicate that the AFUDC cut-off date should be before December 31, 2017, the Public Staff reserves its right to propose an earlier cut-off date.

<u>APPROPRIATE REMAINING USEFUL LIFE FOR METERS REPLACED BY EXPEDITED INSTALLATION OF AMI METERS</u>

Q. PLEASE EXPLAIN YOUR RECOMMENDATION REGARDING THE APPROPRIATE REMAINING USEFUL LIFE FOR METERS THAT HAVE BEEN OR ARE TO BE REPLACED BY AMI METERS AS PART OF THE COMPANY'S AMI DEPLOYMENT.

A. Company witness McManeus states in her testimony that the Company is requesting permission to establish a regulatory asset for meters being replaced under DEC's AMI deployment program. She further states that the depreciation study recovers the remaining net book value of the meters to be replaced over three years, the expected deployment period for the program.

I do not oppose the establishment of a regulatory asset to track the retirement and remaining depreciation of the replaced meters.

However, I do not believe that customers should be charged the entire cost of the replaced meters over a three-year period. Pursuant to information received from the Company, these meters have an average estimated remaining useful life of 15.4 years. I recommend that the meters be depreciated using this remaining useful life, not three years. There is no reason that the recovery of the remaining cost of the retired meters from the Company's customers should be accelerated.

I have provided the 15.4 year remaining useful life to Public Staff witness McCullar for her use in developing the Public Staff's recommended depreciation rates.

NUCLEAR DECOMMISSIONING EXPENSE

Q. WHAT COMMENTS DO YOU HAVE REGARDING NUCLEAR DECOMMISSIONING EXPENSE?

A. In his testimony, Public Staff witness Hinton is recommending that nuclear decommissioning expense be reduced by approximately $19.4 million on an N.C. retail basis, in order to eliminate the currently projected overfunding of decommissioning expense. However, as he notes, DEC has provided information in this proceeding that indicates that under current Nuclear Regulatory Commission and Internal Revenue Service regulations, the

Company may not be allowed to remove monies from the Nuclear Decommissioning Trust Fund (NDTF) to fund this reduction in expense. If DEC cannot remove such funds from the NDTF, its shareholders will be required to provide (i.e., loan) the funds for the expense reduction, on a temporary basis.

Q. IN THE EVENT THE SHAREHOLDERS ARE REQUIRED TO TEMPORARILY PROVIDE THE FUNDS, ARE THERE ACCOUNTING AND RATEMAKING MECHANISMS THAT CAN BE PUT INTO PLACE TO PROTECT THE SHAREHOLDERS?

A. Yes. To understand this fully, one must first take note that the NDTF represents funds put in place to eventually satisfy the Company's nuclear decommissioning obligations. Those funds have been, and will be, provided by the ratepayers over each nuclear unit's life, and will earn a return from the NDTF's investments until expended for actual decommissioning. If the decommissioning periods end without all of the funds being expended, it is appropriate and reasonable to assume that the leftover funds, having been supplied by the ratepayers, will be fully returned to them in such fashion. In other words, any excess funds take on the character of a regulatory liability, which represents funds due to the ratepayer at a future date.

In this particular case, because under the Public Staff's recommendation, the shareholders may be required to temporarily provide excess funds to the ratepayers prior to decommissioning, the ratepayers would essentially "give up" their claim on those funds at the time decommissioning is completed. However, it is important to note that the Public Staff's recommendation is not an acceleration of what one would expect to occur, leaving aside the question of whether funds can <u>currently</u> be removed from the NDTF. The expense reduction recommended by witness Hinton is simply the result of calculating nuclear decommissioning expense using the models that DEC and the Commission have used for decades, without regard to whether funds can be removed from the NDTF.

Since, under the Public Staff's recommendation, the ratepayers would currently "give up" a claim on certain projected excess future funds, I recommend that the Company be allowed to establish a regulatory asset for the difference between the credit nuclear decommissioning expense recommended by witness Hinton and the zero amount of nuclear decommissioning expense proposed by the Company, adjusted appropriately for income tax effects. This regulatory asset would increase by the expense differential each year, at least until the Company performs its next nuclear decommissioning study and cost estimate, at which time it might need to be adjusted. In this manner, if there are in fact excess funds left over when decommissioning is completed, a portion of those funds can be used to satisfy the regulatory asset, and not “double-returned” to the ratepayers.

Q. IS IT CERTAIN THAT THE REGULATORY ASSET WILL SURVIVE UNTIL DECOMMISSIONING IS COMPLETED?

A. No. Under current guidelines, DEC recalculates its nuclear decommissioning funding requirements at least every five years. If, over time, expectations regarding decommissioning costs, future earnings, discount rates, or other items change, it is possible that annual funding requirements will increase. If nuclear decommissioning expense, calculated and charged to expense in a manner that takes into account the credit decommissioning expense recommended by the Public Staff in this proceeding, exceeds nuclear decommissioning expense calculated given the actual NDTF balance, a portion of the extra expense charged as part of cost of service should be used to satisfy the regulatory asset beginning at that time.

Q. HAS THE COMPANY EXPRESSED ANY CONCERN REGARDING YOUR RECOMMENDATION?

A. Yes. The Company has expressed two related concerns, both related to how it might be required to report the effects of the

Commission's action in the financial statements it produces for investors in compliance with Generally Accepted Accounting Principles (GAAP). The first is that because decommissioning activities will not be completed and excess funds distributed until many years into the future, its GAAP auditors may not be willing to express an opinion that the regulatory asset is "probable of recovery," and thus may not allow recognition of the asset in the GAAP financial statements. The second is that even if the GAAP auditors would otherwise allow the regulatory asset to be recognized, they might find that the Commission's action actually comprised a "phase-in plan" under GAAP. Under GAAP, a phase-in plan may exist when a regulator adopts a ratemaking method "in connection with a major, newly completed plant."[5] If a phase-in plan is determined to exist, then any costs deferred in the case by the regulator for regulatory accounting and ratemaking purposes may not be allowed to be deferred for GAAP financial reporting purposes. Company personnel have stated that they believe my regulatory asset recommendation constitutes a phase-in plan.

Q. DO YOU BELIEVE YOUR RECOMMENDATION CONSTITUTES A PHASE-IN PLAN?

[5] Financial Accounting Standards Board, *Accounting Standards Codification*, Section ASC 980-340-20.

A. Although I cannot put myself in the place of the Company's external GAAP auditors, I have an element of doubt as to whether my recommendation actually constitutes a phase-in plan. The greatest reason for my doubt is the simple fact that the Public Staff recommendation is not being made for the purpose of "phasing in" the Company's proposed rate increase (or increasing a rate decrease), nor is it in any way directly related to the bringing into service of the Lee combined cycle facility. It is, instead, an attempt to determine nuclear decommissioning expense in a manner similar to the way nuclear decommissioning expense has been determined for many years and many rate cases, taking into account the fact that funds cannot be removed from the NDTF at the present time. Under the Company's strikingly broad interpretation of a GAAP phase-in plan, almost any new deferral approved by the Commission in a case in which a major generating plant was coincidentally being brought into service could be identified as a phase-in plan, and endanger every other deferral in the case. I am uncertain whether the GAAP standard is meant to be that broad.

Q. DO YOU BELIEVE THAT THE REGULATORY ASSET THAT YOU RECOMMEND, IF APPROVED BY THE COMMISSION, WOULD BE "PROBABLE OF RECOVERY"?

A. I believe that should this Commission approve the establishment of my recommended regulatory asset, the Commission would intend that it be fully recovered through recognition in cost of service, and, as appropriate, through rate changes approved as part of general rate cases, all pursuant to the North Carolina general statutes the Commission's rules and regulations, and its accounting and ratemaking policies and practices. However, as stated previously, I cannot stand in the place of the Company's external GAAP auditors, nor can I substitute my judgment for theirs.

Q. IF YOU KNEW THAT YOUR RECOMMENDATION WOULD RESULT IN A PHASE-IN PLAN, OR THAT THE REGULATORY ASSET YOU RECOMMEND WOULD BE DISALLOWED FOR GAAP PURPOSES DUE TO NOT BEING "PROBABLE OF RECOVERY," WOULD THAT CHANGE YOUR RECOMMENDATION?

A. No. I believe that the actions of this Commission do have economic substance. During my 35-year employment with the Public Staff, I have never become aware of any time that the Commission has failed to appropriately preserve the economic substance of regulatory assets which it has approved. I understand that under the rules of GAAP, and using their own professional judgment, the Company's external GAAP auditors may reach a conclusion that the regulatory assets approved by the Commission may not be recognizable for purposes of the financial statements generated for investors. However, I do not believe that the Commission should substitute the GAAP auditors' judgment regarding GAAP financial statements for investors for its own judgment regarding appropriate and reasonable rates for N.C. retail ratepayers. It is the Commission's responsibility to determine those rates; the purpose of financial reporting is simply to reflect the Commission's exercise of that responsibility. In summary, the Public Staff's recommendation regarding nuclear decommissioning expense is reasonable for the ratepayers, and using a regulatory asset or assets under the Commission's own accounting rules is also sufficient to protect the shareholders' interests.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Appendix A

MICHAEL C. MANESS

I am a graduate of the University of North Carolina at Chapel Hill with a Bachelor of Science degree in Business Administration with Accounting. I am a Certified Public Accountant and a member of both the North Carolina Association of Certified Public Accountants and the American Institute of Certified Public Accountants.

As Director of the Accounting Division of the Public Staff. I am responsible for the performance, supervision, and management of the following activities: (1) the examination and analysis of testimony, exhibits, books and records, and other data presented by utilities and other parties under the jurisdiction of the Commission or involved in Commission proceedings; and (2) the preparation and presentation to the Commission of testimony, exhibits, and other documents in those proceedings. I have been employed by the Public Staff since July 12, 1982.

Since joining the Public Staff, I have filed testimony or affidavits in several general, fuel, and demand-side management/energy efficiency rate cases of the utilities currently organized as Duke Energy Carolinas, LLC, Duke Energy Progress, LLC., and Virginia Electric and Power Company (Dominion Energy North Carolina) as well as in several water and sewer general rate cases. I have also filed testimony or affidavits in other proceedings, including applications for certificates of public convenience and necessity for the construction of generating facilities, applications for approval of self-generation deferral rates, applications for approval of cost and incentive recovery mechanisms for electric utility demand-side management and energy efficiency (DSM/EE) efforts, and applications for approval of cost and incentive recovery pursuant to those mechanisms.

I have also been involved in several other matters that have come before this Commission, including the investigation undertaken by the Public Staff into the operations of the Brunswick Nuclear Plant as part of the 1993 Carolina Power & Light Company fuel rate case (Docket No. E-2, Sub 644), the Public Staff's investigation of Duke Power's relationship with its affiliates (Docket No. E-7, Sub 557), and several applications for business combinations involving electric utilities regulated by this Commission. Additionally, I was responsible for performing an examination of Carolina Power & Light Company's accounting for the cost of Harris Unit 1 in conjunction with the prudence audit performed by the Public Staff and its consultants in 1986 and 1987.

I have had supervisory or management responsibility over the Electric Section of the Accounting Division since 1986, and also was assigned management duties over the Water Section of the Accounting Division during the 2009-2012 time frame. I was promoted to Director of the Accounting Division in late December 2016.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1146

In the Matter of Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	))))	MANESS DIRECT TESTIMONY APPENDIX B

The following legal memorandum has been provided by the Public Staff Legal Division to Public Staff witness Maness in the 2017-18 Duke Energy Carolinas (DEC) general rate case, Docket No. E-7, Sub 1146, as a legal framework to assist him in formulating his testimony and recommendations.

As a legal analysis, this document is not factual testimony or a factual exhibit sponsored by Public Staff evidentiary witnesses. However, it is attached to the testimony of witness Maness because it provides a critical part of the legal basis that informed his investigation into DEC's rate request and his evidentiary recommendations.

MEMORANDUM

TO: Mike Maness

FROM: David Drooz

RE: Equitable Sharing of Coal Ash Costs

I. Overview

Company witness Wright has argued in both the DEC and DEP cases that the coal ash disposal expenditures are "used and useful." From that premise, DEC and DEP argue that the unamortized balance of such costs is legally entitled to a return. This position is apparently based on the idea that "used and useful" costs fall under G.S. 62-133(b)(1), and therefore must receive a return under G.S. 62-133(b)(4).

The argument that coal ash disposal costs are legally entitled to a return is wrong for several reasons. If the Company intended for a portion of the costs already incurred to be considered "the public utility's property used and useful" under G.S. 62-133(b)(1), that portion should have been specifically identified and submitted as such. Instead, the Company has deferred them to an undemarcated regulatory asset, which, under normal utility regulatory accounting, most often consists of costs that otherwise would have been written off to expense, not included in rate base. In a number of past cases, discussed below, the Commission has allowed recovery of costs deferred into a regulatory asset by amortization with no return on the unamortized balance. One of those cases was appealed, and the North Carolina Supreme Court ruled that the Commission had discretion to amortize with no return. (Thornburg I) A return on the unamortized balance was not a legal right.

DEC and DEP seek to distinguish such cases by arguing the deferred costs in past equitable sharing cases were not “used and useful” whereas the coal ash costs in the pending cases are “used and useful.” This argument is misplaced because (a) the nature of many of the costs is that of expenses (e.g., truck and rail transportation of ash) rather than plant in service, (b) “used and useful” modifies “property” in the statute, not “cost,” and the Company has not identified which of its coal ash disposal costs are for “property”; (c) it makes no regulatory sense to defer to a regulatory asset a cost that could be placed in rate base – there is no need to defer “used and useful” plant in service; and (d) the need to defer costs into a regulatory asset, to be recovered through amortization, itself largely identifies those costs as an operating expense (not entitled to a return), without regard to whether the costs are for “property used and useful.”

Finally, it should be noted that G.S. 62-133(d) provides sufficient authority for the Commission to deny a return on the unamortized balance of coal ash disposal costs. This statute is particularly apt in these cases where “coal ash disposal costs” is in large part a euphemism for costs to correct environmental violations and contamination risks created by DEC’s and DEP’s coal ash impoundments. The utilities’ failure to comply with environmental regulations and laws justifies a G.S. 62-133(d) equitable sharing of the cleanup costs even more than in the past cases of environmental cleanup costs for Manufactured Gas Plant facilities. G.S. 62-133(d) may lawfully be used to adjust rates even where a cost is deemed "used and useful" and prudent.

II. The Statutes

G.S. 62-133 provides the legal framework for setting utility rates in a general rate case. It has several components that should be construed to work together. G.S. 62-133(a) states the overarching principle that rates "shall be fair both to the public utilities and to the consumer." The focus here is on the fairness of rates to all parties, not just cost recovery for the utilities.

G.S. 62-133(b) addresses utility cost recovery as a component of rates. In simplified terms, it provides that rates shall be set that allow the utility to earn a fair return on its rate base plus its "reasonable operating expenses." The rate base is defined as "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," minus the cost that has been recovered by depreciation expense. G.S. 62-133(b)(1) (emphasis added). Whether a cost of property is reasonable, or an expense is reasonable, is largely a factual determination for the Commission.

G.S. 62-133(c) provides that the costs of used and useful property and operating expenses, and the amount of revenues, used to determine rates shall be established through operational experience in a 12-month test period. The test period costs and revenues may be updated for "actual changes" through the close of hearing.

G.S. 62-133(d) states: "The Commission shall consider all other material facts of record that will enable it to determine what are reasonable and just rates." As discussed below, this provision delegates authority to the Commission to set rates based on more than just the utility's reasonable costs of property and operating expenses. As provided in G.S. 62-133(b), recovery of a fair rate of return on the reasonable costs of utility property, and recovery of reasonable operating expenses, are important parts of fair rates. Often the Commission's ratemaking determination need go no further. However, as provided in G.S. 62-133(d), there can be circumstances where other material facts must be considered. G.S. 62-133(d) is not empty surplusage; if the General Assembly had intended to limit rate-setting only to recovery of a fair rate of return on rate base and operating expenses, there would be no need for G.S. 62-133(d).

At the same time, the Public Staff recognizes that recovery of a fair return on the reasonable costs of property used and useful, plus recovery of operating expenses, is vital to maintaining reliable utility service.[1] Any rate-setting that departs from simple recovery of utility costs (including the cost of capital in the form of a fair return) must be justified by special circumstances. Examples of such circumstances are summarized below.

[1] This is not to say that the coal ash cost recovery recommendations of the Public Staff will lead to dramatic changes in the costs of financing. While Company witnesses "expressed grave concern" about how such adjustments would be received by rating agencies and investors, the cost recovery risks of coal ash have been well-publicized, known to the investment community, and presumably incorporated into their investment outlook for Duke Energy already.

III. Examples of Past Cases Where Rates Did Not Include All Reasonable Costs or Did Not Include a Return on Deferred Costs

A. Disallowance of Dominion costs that were prudent: State ex rel. Utilities Comm'n v. North Carolina Power, 338 N.C. 412 (1994)

In this case, Virginia Electric and Power Company[2] (VEPCO), providing electric service in North Carolina under the name North Carolina Power, sought a general rate increase. The Commission disallowed $1.39 million of capacity payments made by VEPCO to a co-generator. The cogenerator was a "qualifying facility" (QF) under the Public Utility Regulatory Policies Act of 1978 (PURPA), which meant VEPCO was required by law to purchase the cogenerator's capacity. VEPCO resisted the price being asked by the cogenerator, but the Virginia State Corporation Commission ordered VEPCO to pay the cogenerator at an "avoided cost" rate determined by the Virginia commission. However, the North Carolina Utilities Commission used a different, lower measure for VEPCO's avoided cost rate. The difference meant a reduction of $1.39 million in the North Carolina retail allocation of the reasonable costs for cogeneration capacity.

The Commission also disallowed 50% of the salaries of three executive officers. There was no contention that the officers were overpaid; rather, the issue was whether it was reasonable for ratepayers to be responsible for the full salaries.

The utility appealed, and the Court affirmed the Commission's disallowances. Even though VEPCO was required by a legally binding ruling in Virginia to pay a certain capacity cost to the cogenerator, and therefore VEPCO

[2] Dominion Resources, Inc., owned VEPCO, and its North Carolina operations have also gone under the names Dominion North Carolina Power and Dominion Energy North Carolina.

acted prudently, the Court held that North Carolina could disallow part of that cost as being unreasonably high. The Court reasoned that

> NC Power also argues that the Commission, in deciding the reasonableness of operating expenses, must determine whether management has acted prudently. We disagree.
>
> This Court rejected this argument in *State ex rel. Utilities Comm'n v. Carolina Power & Light Co.*, 320 N.C. 1, 358 S.E.2d 35 (1987), reasoning that:
>
>> Although management prudence may be an important factor considered by the Commission in a general rate case, management prudence vel non does not control the Commission's decision as to whether to adjust test period data to reflect abnormalities having a probable impact on the utility's revenues and expenses during the test period, in order that it may set reasonable rates in compliance with N.C.G.S. § 62-133.
>
> Id. at 12, 358 S.E.2d at 41. The conclusion that management imprudence is only one method of demonstrating that a given expense is unreasonable is also consistent with the standard applied in *State ex rel. Utilities Comm'n v. Intervenor Residents*, 305 N.C. 62, 286 S.E.2d 770 (1982).

State ex rel. Utilities Comm'n v. North Carolina Power, 338 N.C. 412, 421-22 (1994).

The Court likewise upheld the disallowance of 50% of executive salaries: "NC Power argues that absent a showing that such salaries are unreasonable or will not actually be incurred, there was no basis for the exclusion of these expenses. We disagree." The Court noted that Public Staff witness Maness had testified as to why it was not appropriate for ratepayers to bear the full cost of those salaries, and this provided substantial evidence to support the Commission's order. Id. at 423-24. This North Carolina Power decision stands for the proposition that while a cost may have been prudently and reasonably incurred by a utility, it is appropriate for the Commission to inquire further whether it is reasonable to charge that cost to customers in rates.

B. Manufactured Natural Gas cleanup costs

The Commission's ratemaking treatment of environmental compliance costs for manufactured natural gas plant (MNP) facilities is another example. The seminal decision is the Commission's 1994 order in Docket No. G-5, Sub 327. In that general rate case of Public Service Company of North Carolina, Inc., (PSNC), the Commission ordered an amortization of MGP cleanup costs that had been deferred into a regulatory asset and ordered that there be no return on the unamortized balance. The 1994 PSNC order applied to facts with striking similarities to the Duke Energy coal ash costs under current consideration. In both situations, a previously accepted practice had resulted in significant liabilities for environmental cleanup. The Commission allowed the cleanup (or "environmental compliance" in Duke Energy's words) costs to be deferred to a regulatory asset.

In the 1994 PNSC case, the relevant finding states:

> 29. The unamortized balance of MGP costs should not be included in rate base. The resulting sharing of clean-up costs between ratepayers and shareholders will provide PSNC motivation to minimize costs and to pursue contributions from other potentially responsible parties and insurers.

The supporting Evidence and Conclusion section includes the following explanation:

> Mr. Hoard also recommended that the unamortized balance of MGP costs not be included in rate base. Public Staff witness Hoard testified that he does not believe it is the responsibility of current ratepayers to absolve shareholders of all cost responsibility for cleaning up the sites. He stated that excluding the unamortized balance of deferred MGP costs from rate base would require shareholders to share in the cost by being required to bear the

carrying costs associated with the unamortized balance of MGP costs. Mr. Hoard noted that this ratemaking treatment is consistent with the Commission's treatment in the past for abandoned plant costs by electric utilities. Mr. Hoard also testified that although interest is accrued on the deferred gas cost accounts of gas utilities, the Commission does not normally allow utilities to accrue interest on expenses deferred as the result of accounting orders.

Company witness Dickey testified that if the Public Staff's ratemaking treatment is adopted, carrying costs on the uncollected balance should be allowed to lessen the impact on PSNC. He recommended that the overall cost of capital rate or 10% be applied to the uncollected balance.

….

The Commission concludes that the Company's proposed MGP tracker should not be approved. Assuming, without deciding, that the Commission would have legal authority to approve such a tracker, the Commission believes that this is not an appropriate situation for such an extraordinary rate mechanism. Provisional, non-fixed rates should be reserved for limited circumstances. Public Service is just beginning to investigate MGP clean-up. Management of the MGP sites could take decades and cost tens of millions of dollars. Approval of the proposed tracker would have far reaching consequences which cannot be known at this early stage. Further, complicated prudency issues are likely to arise in connection with the MGP clean-up. Among the factors to be considered in passing these costs on to the ratepayers are whether the Company's initial operation of each site was prudent, whether the clean-up costs were prudently incurred, and whether contributions should be provided by prior and joint owners. The Company's proposed tracker would provide a limited opportunity for review of these prudency issues. Finally, the Company's proposed tracker should be rejected because a pass through of MGP clean-up costs to current ratepayers will inevitably undermine PSNC's motivation to minimize costs and to pursue contributions from others.

Based on the foregoing concerns, the Commission rejects the Company's proposed MGP tracker.

On the other hand, the approach advocated by the Public Staff addresses all of these concerns.

….

> The Commission concludes that the Company should account for the MGP clean-up costs in the manner described by Mr. Hoard. The Commission concludes that this approach is appropriate as a matter of law and as a matter of policy. It is proper and in the public interest for the Commission to allow PSNC to recover the prudently-incurred clean-up costs from current ratepayers as reasonable operating expenses, even though the MGP sites are not used and useful in providing gas service to current customers. At the same time, however, it is not appropriate for ratepayers to relieve shareholders of all cost responsibility associated with the ratemaking treatment of MGP clean-up. We conclude that the proper balance between ratepayer and shareholder interests is achieved by amortizing the prudently-incurred costs to O&H expenses in general rate cases but denying the Company any recovery from ratepayers of the carrying costs on the deferred and the unamortized MGP clean-up cost balances. A sharing of MGP clean-up costs between ratepayers and shareholders has been adopted by several other state commissions. See, e.g., AG Dickey Cross Examination Exhibits 1 and 2; 146 PUR 4th 123; 147 PUR 4th 1. This treatment is analogous to the treatment ordered by this Commission for the costs of abandoned nuclear plants of electric utilities, which was upheld as reasonable by the North Carolina Supreme Court. See State ex. rel. Utilities Commission v. Thornburg, 325 N.C. 463 (1989). This approach will provide an appropriate forum where prudency issues can receive the regulatory oversight they deserve in the context of general rate cases. This approach will give the Company an incentive to minimize clean-up costs and to pursue contributions. Finally, the Commission concludes that this approach will result in greater rate stability. Rather than recovered over a 12-month period, the costs can be amortized over an appropriate period, determined in each case, depending upon their magnitude.

Eighty-Fourth Report of the North Carolina Utilities Commission Orders and Decisions, pp. 159 ff.

This decision is notable support for the Public Staff's recommendations in Docket Nos. E-2, Sub 1142, and E-7, Sub 1146, for several reasons. First, it involves environmental cleanup costs found to be prudent. Second, it approves an equitable sharing of those costs between ratepayers and shareholders "as a matter of law and as a matter of policy." Third, it rejects alternative recovery mechanisms, such as a tracker, in favor of the amortization of costs with no return.

Fourth, it analogizes the ratemaking treatment for environmental cleanup costs to that of abandoned nuclear plant costs. Fifth, it notes that the MGP sites are not used and useful in providing gas service to current utility customers; likewise, virtually all the use of ash impoundments as a step in the production of electricity occurred in the past (and CAMA provides for cessation of ash being sluiced to impoundments[3], guaranteeing this will not be a step in providing electricity to customers in future years). Sixth, equitable sharing incentivizes the utility to minimize its cleanup costs going forward; DEC and DEP both expect to incur substantial cost ash cost in the future so the same reasoning is applicable in their cases. Seventh, the Commission notes that the recovery period may vary with the magnitude of costs, which supports the Public Staff position in the pending cases that the magnitude is relevant to the amortization period.

In summary, the Commission in the PSNC case thoroughly considered the issues related to amortization with no return, for environmental compliance/cleanup costs, and that decision (along with ratemaking treatment of MGP in other cases) is consistent with the Public Staff's position on equitable sharing of coal ash costs in the pending DEC and DEP cases. Furthermore, as noted by Company witness Wright, the MGP facilities had prior owners before acquisition by the utilities seeking rate recovery, whereas DEC and DEP (or their predecessors) have always owned the coal ash impoundments. In this regard, DEC and DEP have greater culpability for environmental violations from those impoundments than PSNC (and other utilities that inherited MGP facilities) does

[3] See G.S. 130A-309-210(e).

for its MGP facilities. The responsibility for environmental compliance regarding surface water and groundwater was on DEC and DEP all along, they failed to comply on numerous occasions, and thus even if "prudent" it is appropriate to have the shareholders of those companies bear a greater share of the cleanup costs under an equitable sharing approach.

C. Recovery of costs for abandoned nuclear plants

By the time of its September 30, 1983, general rate case order in Docket No. E-7, Sub 358, the Commission had considered ratemaking treatment for abandoned nuclear plants in several cases. It addressed the request of Duke Power Company to recover the costs associated with the cancellation of the Cherokee plant's Units 1, 2, and 3 and to change the amortization period allowed on cancellation costs for the Perkins plant. The Commission approved an amortization of the Cherokee Units over a ten-year period, with no portion of the costs in rate base (i.e., no return on the unamortized balance). The Commission also required Duke to continue collecting the costs of the Perkins cancellation costs over a five-year period with no inclusion of the unamortized costs of the project in rate base. The Commission stated as follows:

> The proper ratemaking treatment of abandonment losses related to electric generating plants has been before the Commission in several cases and will continue to arise in future cases. The Commission has, therefore, undertaken to reexamine this important issue in order to develop a more consistent and equitable approach to it. The Commission's ultimate responsibility with respect to ratemaking is to fix rates for the service provided which are fair and reasonable both to the utility and to the consumer. G.S. 62-133(a); State ex rel. Utilities Commission v. Morgan, 277 N.C. 255, 177 S.E. 2d 405 (1970); State ex rel. Utilities Commission v. Area Development, Inc., 257 N.C. 560, 126 S.E. 2d 325 (1962).

Although the parties to this proceeding may disagree as to the proper amortization period, they generally agree that the Company should be allowed to recover the prudently invested cost of its abandonment losses through amortization over some period of time. The Commission, based upon the evidence presented, must determine what is a fair amortization period in order to fairly allocate the loss between the utility and the consumer. With regard to the Cherokee Units 1, 2, and 3, the Commission concludes that utilization of a 10-year amortization period is proper and fair in this proceeding for the reason that such an amortization period, particularly when considered in conjunction with the Commission's decision, as subsequently discussed, to allow Duke no return on the unamortized balance, will service to more reasonably and equitably share the burden of such plant cancellations between the Company's shareholders and its present and future ratepayers.

Furthermore, the Commission has determined that it is neither fair nor reasonable to include any portion of the unamortized balance of the prudently incurred abandonment losses associated with the Cherokee units in rate base and that no adjustment should be allowed which would in fact have the effect of allowing the Company to earn a return on the unamortized balance. The Commission has concluded that this treatment provides the most equitable allocation of the loss between the utility and the consumer. It would be inequitable to place the entire loss of expenditures that were prudent when made on the utility. Thus, amortization should be allowed. However, on the other hand, the ratepayer must not bear the entire risk of the Company's investment. A middle ground must be found on which the Company bears some of the risk of abandonment and the ratepayer is protected from unreasonably high rates. The losses resulting from cancellations of utility generating plants will inevitably be borne by one or a combination of three groups: the utility investors, the ratepayers, and the income taxpayer. The above referenced study on nuclear plant cancellations prepared by the United States Department of Energy indicates that a 10-year amortization of such losses will distribute costs in proportions that the Commission considers fair and equitable, even considering the effects of CWIP in rate base in North Carolina. The Commission believes, and thus concludes, that this will result in a fair and reasonable treatment for both the utility and its customers.

Seventy-Third Report of the North Carolina Utilities Commission, pp. 255 ff.

Notably, the Commission did not provide any quantification or basis for how it reached its amortization periods. The Commission does not state the "proportions" it considers fair, and the determination of both those proportions and what is equitable would vary from case to case, not the least because the authorized rate of return will have a significant impact on the sharing proportions for a given amortization period. The Public Staff approach to an amortization period in the present case is no more "arbitrary and capricious" than the approach taken by the Commission in past cases. In fact, by defining "equitable" sharing to be an equal (50%-50%) sharing, and backing into an amortization period that achieves that result, the Public Staff has explained a principled reason for its amortization period that was lacking in past cases. Ultimately, the amortization period, and thus the portion of costs shared by investors and the portion shared by ratepayers, is a qualitative judgment. It is no more conducive to formulaic quantification than other qualitative judgments the Commission must make, such as what qualifies as "reasonable," the impact of changing economic conditions on consumers when setting a rate of return, and the various amortization periods chosen for nuclear plant abandonment costs and MGP facility environmental cleanup costs.

Also notable in the Commission's 1983 Duke Power Company case is the reference to a "middle ground." Nuclear cancellation costs, as with some of the coal ash costs, were prudently incurred. At the same time, with coal ash as with nuclear abandonment costs, it is not reasonable to impose such costs on ratepayers given both the extraordinary nature and magnitude of the costs. Without a “middle ground,” or equitable sharing, rates would not be “fair” in the words of G.S. 62-133(a) or “reasonable and just” in the words of G.S. 62-133(d), even for prudently incurred costs.

In its post-hearing brief in Docket No. E-2, Sub 1142, DEP offered its interpretation of two successive cases on ratemaking treatment of plant abandonment costs for Shearon Harris Units 2, 3, and 4. Those two cases are Docket No. E-2, Sub 526, decided by the Commission on August 27, 1987, and Docket No. E-2, Sub 537, decided on August 5, 1988. Both orders were appealed, and the N.C. Supreme Court ruled on the Sub 526 case in State ex rel. Utils. Comm’n v. Thornburg, 325 N.C. 463 (1989) (labeled as “Thornburg I” in the DEP brief in Docket No. E-2, Sub 1142[4]). The Court decided the Sub 537 appeal in State ex rel. Utils. Comm’n v. Thornburg, 325 N.C. 484 (1989) (labeled as “Thornburg II” in the DEP brief).

Carolina Power & Light Company (CP&L) filed these two rate cases in close succession because the Commission had approved a phase-in of new rates for recovery of the Harris plant costs. In the first case, Sub 526, the Commission noted its previous orders on recovery of abandonment losses for Harris Units 2, 3, and 4:

> The ratemaking treatment of the Harris abandonment losses has been considered by the Commission in previous general rate cases of CP&L. In Docket No. E-2, Sub 444, the Commission allowed a recovery of the cost associated with cancelled Harris's Units 3 and 4 over a 10-year period with inclusion of the interest arising from the debt financing portion of the unamortized balance. In Docket No.

[4] In Court opinions cited herein, the Court has a different numbering convention: “Thornburg I” in the DEP brief and in this document is referred to as “Thornburg II” by the Court.

> E-2, Sub 461, the Commission reexamined the ratemaking treatment of abandonment losses in order to develop a more consistent and equitable approach. The Commission determined that CP&L should be allowed to continue amortization of the Harris abandonment losses, but that no ratemaking treatment should be allowed which would have the effect of allowing CP&L to earn a return on the unamortized balance. The Commission concluded that this treatment provided the most equitable allocation of the loss between the utility and its ratepayers. In CP&L's last general rate case, Docket No. E-2, Sub 481, the Commission dealt with CP&L's decision to cancel the construction of Harris Unit 2. Consistent with its treatment of the earlier Harris cancellations, the Commission ruled that the abandonment losses of Harris Unit 2 should be amortized over ten years with no return allowed on or with respect to the unamortized balance. Consistent with these previous orders, CP&L proposes in this case to include in operating expenses the amortization of the three abandoned Harris units.

The Attorney General challenged CP&L's request on the grounds that abandoned plant costs are capital expenditures in nature, and therefore cannot be treated as operating expenses to be amortized over a period of years. Because abandoned plant is not "used and useful," and according to the Attorney General could not be treated as an operating expense, the argument was that no recovery of abandonment losses was legal.

The Commission rejected the Attorney General's argument for two reasons. First, the Commission concluded that "operating expenses" is a concept that may be liberally applied, and it was appropriate to apply it to abandonment losses that were deferred into a regulatory asset for amortization. Second, the Commission referred to G.S. 62-133(d) for authority to allow an amortization (without a return on the unamortized balance) of abandonment losses as a way to achieve reasonable and just rates. The Commission also noted its treatment was consistent with decisions in a majority of other jurisdictions.

On appeal, the Court affirmed. Thornburg I. The Court stated that the "used and useful" test was irrelevant to abandonment costs that were deferred into a regulatory asset, as the "used and useful" requirement only applied "to the reasonable original cost of the public utility's *property*, the rate base component of which is described in N.C.G.S. § 62-133(b)(1)." Id. at 477 (emphasis in original). The nuclear plant abandonment costs included "iron in the ground" property, but nonetheless were converted to an operating expense, liberally construed, once they were deferred into a regulatory asset. The deferral drove the categorization as operating expense. The Court agreed with the Commission that "operating expense" should be liberally construed and was proper to apply to amortization of abandonment losses (and also natural gas exploration cost, as ordered in another case that was cited in Thornburg I).

Thornburg I also held that that the Commission's decision was authorized by G.S. 62-133(d) as well, and that strong public policy reasons reflected in decisions from other jurisdictions supported an equitable sharing through amortization with no return on the unamortized balance. Id. at 476-81. Finally, the Court held that the Commission acted within its discretion in approving the amortization with no return. Id. at 481.

The Public Staff relied on this holding to support the legality of its equitable sharing recommendation in the DEP rate case, Docket No. E-2, Sub 1142, and likewise relies on it for legal support in the present case, Docket No. E-7, Sub 1146. DEP's post-hearing brief argued that "The Public Staff has picked the wrong Commission Order, and the wrong *Thornburg* case." The Company's reasoning is that coal ash costs are different from abandoned plant costs. In particular, DEP argues, the coal ash costs are "used and useful" expenditures. Apparently DEP believes that the coal ash costs qualify for a return under G.S. 62-133(b)(1), and this is not discretionary with the Commission.

DEP's argument is misplaced for multiple reasons. As stated in the testimony of witness Maness in Docket No. E-7, Sub 1146, deferral of expenses incurred in the past as a regulatory asset, instead of treating them as plant in service that goes into rate base, is consistent with their character as operating expenses, as that term is liberally construed by the Commission and the Court. It does not matter whether they were abandonment losses or useful environmental cleanup costs; what matters is that the costs were deferred to a regulatory asset. Indeed, the Commission has repeatedly ordered amortization with no return for cleanup costs of environmental problems created by MGP facilities.

In addition, Company witness Bateman in her "run rate" proposal described the recovery of ongoing coal ash costs as "O&M" (Operations and Maintenance), which is an operating expense: "This adjustment increases O&M to reflect the expected ongoing annual level of expenses the Company will incur in connection with compliance with federal and state environmental requirements related to closing coal ash ponds." (Docket No. E-2, Sub 1142, T 6, pp 123-24) DEC accounting witness McManeus presents identical direct testimony in Docket No. E-7, Sub 1146. The already incurred coal ash costs are no different in character than the expected ongoing level of "expenses."

Moreover, a substantial amount of those costs include items that would be operating expenses even if not deferred into a regulatory asset, such as transportation of ash from one site to another. DEP and DEC have made no effort to distinguish coal ash costs that might be "cost of the public utility's property used and useful," entitled to rate base treatment and a return under G.S. 62-133(b), from coal ash costs that are operating expenses under G.S. 62-132(c). The idea that "used and useful" operating expenses are legally entitled to a return is contrary to the statutory requirement that applies the "used and useful" requirement only to the utility's "property."[5]

Whether construction costs of coal ash basins were previously included in the utility's rate base has no bearing on whether subsequent expenditures ("environmental compliance" costs to monitor the ash for contamination, excavate it where necessary and transport it to a safer disposal location, or otherwise remediate the risk of coal ash pollution and close the ash basins) are "used and useful." A furnace and boiler at a generating plant qualify as rate base property, but that does not convert the "used and useful" fuel burned in the furnace from operating expense to rate base property.

In its post-hearing brief, DEP next argues that Thornburg II is more relevant. This appellate decision followed the Commission's August 5, 1988, order on the second CP&L rate case to recover Harris plant costs (Sub 537 order). In that order

[5] DEP argued that some coal ash basin closure costs were directly placed into rate base, in Working Capital. As Mr. Maness explains in his testimony in this proceeding, mere classification in the Company's exhibits as "working capital" does not automatically impart to the proposed regulatory asset the true nature of "working capital," nor does it mean the outcome in the Company's accounting exhibit is the proper ratemaking treatment.

the Commission allowed most of the costs of Harris Unit 1 into rate base as property used and useful. A modest amount of the construction costs were disallowed as imprudent. In addition, the Commission allowed a recovery of, but not a return on, the cancellation (or abandonment) costs for Harris Units 2, 3, and 4, and coal-fired Mayo Unit 2. The Commission found the cancellation costs to have been prudently incurred, and that an equitable sharing between ratepayers and shareholders was appropriate. The Commission's legal reasons in support of equitable sharing included (1) its interpretation that the statutory definition of "operating expense" could include abandonment losses, and (2) that

> Further support for the Commission's conclusion is provided by G.S. 62-133(d). This section of the statute provides that the Commission "shall consider all other material facts of record that will enable it to determine what are reasonable and just rates." All sections of G.S. 62-133 must be given weight in fixing rates. "By the adoption of this statute, the legislature intended to establish an overall scheme for fixing rates and must be interpreted in its entirety in order to comply with the legislative intent." <u>State ex. rel. Utilities Commission vs. Duke Power Company</u>, 305 N.C. 1, at 12 (1982). Taking the statute as a whole, and with a view to the purposes of the Public Utilities Act, the Commission finds our previous treatment of the Harris abandonment losses to be just and reasonable and we hereby reaffirm that treatment.

(From the Evidence and Conclusions for Finding of Fact No. 11)

Also in the Sub 537 order, the Commission determined that the original four-unit cluster design had resulted in some excess plant with respect to the one unit that became operational:

> CP&L's utilization of the cluster design, while prudent in 1971 and 1975 and thereafter, has in fact resulted in the construction of excess common facilities at the Harris Plant in the fuel handling building, the waste processing building, the water treatment building, and the diesel generator and fuel oil tank building.

(Id.) The Commission concluded that $180,558,000 of costs for common facilities should be treated like abandonment costs, and thus amortized over ten years with no return.

On appeal, the Court noted that the cost of common facilities designed to serve all four units, but serving only Unit 1, was approximately $570,000,000 more than if the facilities had been designed and built just for Unit 1. (Thornburg II at 488) The Court ruled that the Commission erred when it included $389,442,000 of the excess common facilities costs in rate base, and amortized only the remaining $189,558.000. The Court held that these costs should be treated for ratemaking purposes the same as the $180,558,000 amount of excess plant costs and the abandoned plant costs. Namely, the entire $570,000,000 cost of excess plant should be amortized over ten years as an operating expense, with no return.

There was no issue about the excess plant being "property," but in reaching this decision, the Court's ruling makes clear that costs to be included in rate base must be property (as well as "prudent" and "used and useful"):

> Section 62-133 provides a step-by-step procedure for the Commission to follow in fixing these rates. We reviewed the public utility ratemaking formula in *State ex rel. Utilities Comm. v. Thornburg*, 325 N.C. 463, 385 S.E.2d 451 (1989) (*Thornburg II*).
>
> > This statute 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 REQUIREMENTS
> >
> > The rate base is the reasonable cost of the utility's property which is used and useful in providing service to the public, minus accumulated depreciation, and

> plus the reasonable cost of the investment in construction work in progress. *See* N.C.G.S. § 62-133(b)(4) (Cum. Supp. 1988 & 1982 Repl. Vol.); C. F. Phillips, Jr., *The Regulation of Public Utilities* 332 (1984). Operating expenses generally include costs for fuel, wages and salaries, and maintenance, as well as annual depreciation charges and taxes. C. F. Phillips, Jr., *The Regulation of Public Utilities* 229 (1984). The rate of return is a percentage multiplier applied to the rate base to produce the amount of money the Commission concludes should be earned by the utility, over and above its reasonable operating expenses. *See* N.C.G.S. § 62-133(b)(4) (Cum. Supp. 1988 & 1982 Repl. Vol.).
>
> 325 N.C. at 467 n.2, 385 S.E.2d at 453 n.2.
>
> In this portion of the appeal, <u>we are concerned with the procedure for determining what goes into the *rate base*</u>. In determining what goes into the rate base, the statute directs the Commission to
>
> > (1) Ascertain the reasonable original cost of the public utility's <u>property</u> 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 . . . .
>
> N.C.G.S. § 62-133(b)(1) (Cum. Supp. 1988).
>
> The statute sets out a two-part test for the Commission to use in deciding what goes into the *rate base* for all costs except costs of construction work in progress. The Commission must: (1) determine the *reasonable* original cost of the <u>property</u> and (2) determine if the <u>property</u> is "used and useful, or to be used and useful within a reasonable time after the test period." *Id.* If the costs in question do not meet both parts of the test, the costs may not be included in the *rate base* for ratemaking purposes. *See id.*; N.C.G.S. § 62-133(b)(4) and (5).

<u>Thornburg II</u> at 490-91 (<u>emphasis added</u>).[6] As described above, the reasonable cost for used and useful utility <u>property</u> goes into rate base and earns a return;

---

[6] The quoted portion cites to "Thornburg II" but it is the Court decision that DEP's brief refers to as "Thornburg I."

otherwise, reasonable costs are treated as operating expenses (which are not statutorily required to earn a return).

The DEP post-hearing brief states that Thornburg II "held that the Commission did not have the discretionary power to effectuate its 'equitable sharing' decision." This is wrong; it is not the Court's holding. The Court holding in Thornburg II is that the Commission had no legal basis to include part of the excess facilities in plant. Instead, the Court held all the $570,000,000 of excess facilities costs must be equitably shared. Equitable sharing is the result of treating these costs as operating expenses to be amortized with no return, the same as abandonment losses:

> A fair reading of the findings and conclusions of the Commission in this case makes it clear that if Harris Units 2, 3, and 4 had never been undertaken, CP&L would have avoided the approximately $570,000,000 in costs for the common facilities to serve the abandoned Units 2, 3, and 4. The Commission having found that the decision permitting the incurring of these costs was prudent, it is appropriate that these costs be treated as cancellation costs of the abandoned units and recovered as operating expenses through amortization. *Thornburg II*, 325 N.C. 463, 385 S.E.2d 451.

Thornburg II at 498.

Because the Thornburg II decision focused on whether part of the excess plant was improperly allowed into rate base, it is not particularly relevant to the question in the pending DEP and DEC cases. Thornburg I is relevant because it held that the Commission has the discretion to take a cost deferred into a regulatory asset, treat it as a form of operating expense, and provide for it to be recovered through amortization over a period of years, with no return on the unamortized balance. Under Thornburg I, the choices of whether to allow a return on the unamortized balance, and the period of amortization, are within the Commission's discretion, although of course the discretion is not unbounded.

IV. The Unconstitutional Taking Concept

The DEP post-hearing brief makes brief reference to the concept that an unconstitutional taking may occur if rates are not fixed to allow a utility to recover its costs. There is an implication here, but the Company wisely does not go so far as to state that the Public Staff's equitable sharing recommendation would be an unconstitutional taking.

Denial of cost recovery, particularly with respect to a portion of a utility's return, normally does not amount to unconstitutional taking. Equitable sharing has been ordered in several cases as discussed above. The Court directly upheld it in Thornburg I and applied it in Thornburg II. The Commission has also imposed rate of return penalties on utilities for poor service. There are few cases on unconstitutional taking claims in the arena of utility regulation; typically they involve pre-existing contracts for electricity that are overridden by Commission ratemaking. The Commission's authority has been upheld as a proper exercise of the police powers of the State. See, e.g. State ex rel. Utilities Com. v. North Carolina Natural Gas Corp., 323 N.C. 630, 643 (1989): This Court has recognized "[u]nder the police power the state has authority to enact legislation to regulate the charges and business of a public utility ...." (Citations omitted.)

V. DNCP Rate Case as Precedent

Testimony in both the pending DEC and DEP case, and the DEP post-hearing brief, state that the 2016 general rate case decision for Dominion North

Carolina Power (DNCP), Docket No. E-22, Sub 532, involved essentially identical coal ash cost recovery issues as the DEP and DEC. The Public Staff stipulated to, and the Commission approved, a five-year amortization of DNCP coal ash costs, with a return on the unamortized balance. DEP and DEC argue that a different decision in their cases would be arbitrary and capricious.

This is yet another misplaced argument. The primary reasons behind the equitable sharing recommendations of the Public Staff in the DEC and DEP rate cases are (1) the extensive environmental violations committed by the Companies, and (2) the magnitude and uniqueness of the costs. It is true that the coal ash costs are just as extraordinary, or unique, for DNCP as for DEC and DEP. However, the extent of environmental violations, and the magnitude of costs, are in no way comparable between the Duke companies versus DNCP.

On cross-examination, DNCP witness Mitchell testified:

> Q With regard to Attorney General Mitchell Cross Exhibit 2, have there been any adjudications, fines or penalties against the Company with regard to disposal of coal ash?
>
> A Not to my - -
>
> Q Not - -
>
> A Not to my knowledge - -
>
> Q Okay
>
> A - - but - -
>
> Q Thank you. And I believe - - and if Mr. McLeod is a better witness for this, I believe you have roughly $84 million in cost incurred that you're seeking recovery of in this case related to CCR disposal cleanup; is that correct?

A That's correct, subject to be checking the value, but yes, that's correct.

Q Okay.

A Eighty-four (84) million, correct.

(T 6, p 192, in Docket No. E-22, Sub 532) Mr. Mitchell clarified that the $84 million for coal ash costs was a system number. (T 6, p 193) Additionally, Public Staff witness Maness noted that while several environmental claims had been filed, there had not yet been any adjudications against the Company or fines or penalties, and the Public Staff was not aware of any significant costs resulting from the pending proceedings to date. (T 8, pp 345-46)

Most notable in the DNCP case is what does not appear in the record: there was none of the evidence of monitoring well reports showing extensive groundwater violations at every coal-fired plant, as is the case with Duke Energy. There was not the extensive evidence of unlawful discharges to surface waters, as is the case with Duke Energy. There was no criminal fine, nor multi-million dollar settlements of penalty proceedings, as is the case with Duke Energy. This is not to say DNCP's parent company is without coal ash-related environmental violations; rather, the DNCP rate case did not uncover such violations. This is a major difference from the DEC and DEP rate cases.

The magnitude of cost is also a major difference. Page 55 of the Commission's order in the DNCP rate case shows the North Carolina retail share of the coal ash costs placed into a regulatory asset for amortization is $4.3 million. This is a small fraction of the costs shown by DEC and DEP in their rate cases.

Not only do material facts about coal ash costs in the DNCP rate case differ from those for DEC and DEP, justifying a different result, but the amortization period and return approved in the DNCP case were the product of a settlement stipulation negotiated between the Public Staff and DNCP. The Stipulation states in part:

> B. Neither this Stipulation nor any of its terms or conditions shall be admissible in any court or before the Commission except insofar as the Commission is addressing litigation arising out of the implementation of the terms herein or the approval of this Stipulation. This Stipulation shall not be cited as precedent by any of the Stipulating Parties with regard to any issue in any other proceeding or docket before this Commission or in any court.
>
> C. The provisions of this Stipulation do not reflect any position asserted by any of the Stipulating Parties, but reflect instead the compromise and settlement among the Stipulating Parties as to all of the issues covered hereby. No Stipulating Party waives any right to assert any position in any future proceeding or docket before this or any other Commission and in any court.
>
> D. The Stipulation is the product of negotiation between the Stipulating Parties, and no provision of this Stipulation shall be strictly construed in favor or against any Party.

Where Duke Energy argues that it is entitled to the same ratemaking treatment as established in a negotiated settlement between other parties, or else the Commission's decision will be "arbitrary and capricious," then it is mistaken about the law. This is especially true given the factual differences between the cases. Moreover, there would be no better way to deter the Public Staff from entering into settlements than to use the settlement terms to resolve similar issues disputed in subsequent non-settled cases in the same forum.

VI. Conclusion

Contrary to the position of DEC and DEP, the Commission has legal authority to order an equitable sharing of deferred coal ash costs. An amortization with no return is allowable for two independent reasons: (1) a regulatory asset may appropriately be classified as a form of operating expense, which is not entitled by law to a return, and (2) the setting of reasonable and just rates under G.S. 62-133(d) allows the Commission to provide for recovery over time with no return, especially for extraordinary costs of great magnitude. This ratemaking treatment is even more justified when considering the impact of extensive coal ash-related environmental violations by the utility.

INDEX TO MANESS EXHIBIT 1

Duke Energy Carolinas
Docket No. E-7, Sub 1146
North Carolina Retail Operations
ADJUSTMENT TO DEFERRED
ENVIRONMENTAL COSTS
For the Test Year Ended December 31, 2016
(in Thousands)

Maness Exhibit 1
Schedule 1

Line No.	Item	NC Retail Amount	
	Income statement impact		
1	Balance for Amortization	$ 457,153	1/
2	Years to Amortize	27	2/
3	Annual amortization per Public Staff (L1 / L2)	16,932	
4	Annual amortization per Company	107,873	3/
5	Public Staff adjustment to amortization expense (L3 - L4)	$ (90,941)	
6	Statutory tax rate	23.6619%	4/
7	Public Staff adjustment to income taxes (-L5 x L6)	$ 21,518	
	Rate base impact		
8	Coal Ash Balance at May 1, 2018 per Public Staff (L1)	$ 457,153	
9	Less annual amortization (-L3)	(16,932)	
10	Annualized Coal Ash Deferral Balance per Public Staff (L8 + L9)	440,222	
11	Coal Ash Deferral Balance per Company	431,491	5/
12	Public Staff annualization adjustment to coal ash deferral balance (L10 - L11)	8,731	
13	Adjustment to remove remaining coal ash deferral balance from rate base (-L10)	(440,222)	
14	Total Public Staff adjustment to regulatory assets and liabilities (L12 + L13)	$ (431,491)	
15	Adjustment to ADIT (-L14 x Company deferred income tax rate of 37.1515% 6/)	$ 160,305	

1/ Maness Exhibit 1, Schedule 1-1, Line 41, Column (k).
2/ Amortization period recommended by Public Staff to achieve equitable sharing.
3/ McManeus Revised Supplemental Exhibit 1, Page 61, NC-1801(C), Line 8.
4/ Boswell Exhibit 1, Schedule 1-3, Line 8.
5/ McManeus Revised Supplemental Exhibit 1, Page 61, NC-1801(C), Line 22.
6/ McManeus Revised Supplemental Exhibit 1, Page 61, NC-1801(C), Line 28.

Duke Energy Carolinas
Docket No. E-7, Sub 1146
North Carolina Retail Operations
AMORTIZATION SCHEDULE FOR DEFERRED ENVIRONMENTAL COSTS
For the Test Year Ended December 31, 2016
(in Thousands)

Maness Exhibit 1
Schedule 1-1

		Duke Energy Carolinas Coal Ash Spend			Duke Energy Carolinas Coal Ash Deferral (North Carolina)							
Line No.	Description	System Spend per Company 1/	Public Staff Adjustments 2/	System Spend per Public Staff 3/	% to NC for Spend 4/	Beginning Balance 5/	NC Spend 6/	Ending Balance 7/	Deferred Cost of Debt 8/	Deferred Cost of Equity 10/	Total Return 11/	Ending Balance 12/
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Dec-14							$ -				
2	Jan-15	$ 223	$ (23)	$ 200	67.3641%	$ -	$ 135	135	$ 0	$ 0	$ 0	$ 135
3	Feb-15	1,853	(190)	1,663	67.3641%	135	1,120	1,255	1	3	4	1,260
4	Mar-15	4,025	(412)	3,613	67.3641%	1,255	2,434	3,689	3	11	14	3,708
5	Apr-15	8,354	(855)	7,499	67.3641%	3,689	5,052	8,741	8	28	36	8,795
6	May-15	28,361	(3,046)	25,315	67.3641%	8,741	17,053	25,794	22	78	100	25,948
7	Jun-15	17,519	(2,237)	15,282	67.3641%	25,794	10,294	36,088	40	139	179	36,422
8	Jul-15	23,835	(3,238)	20,597	67.3641%	36,088	13,875	49,963	55	194	249	50,545
9	Aug-15	3,365	(1,039)	2,326	67.3641%	49,963	1,567	51,530	65	229	294	52,405
10	Sep-15	19,823	(2,792)	17,031	67.3641%	51,530	11,473	63,002	73	258	331	64,209
11	Oct-15	23,529	(2,998)	20,531	67.3641%	63,002	13,831	76,833	89	315	404	78,445
12	Nov-15	16,794	(2,050)	14,744	67.3641%	76,833	9,932	86,765	105	369	473	88,850
13	Dec-15	22,429	(2,791)	19,638	67.3641%	86,765	13,229	99,994	119	421	540	102,619
14	Jan-16	18,450	(2,768)	15,682	67.4187%	102,619	10,573	113,192	139	486	625	113,817
15	Feb-16	14,603	(1,989)	12,614	67.4187%	113,192	8,504	121,696	151	529	680	123,001
16	Mar-16	20,872	(2,919)	17,953	67.4187%	121,696	12,104	133,800	164	576	740	135,845
17	Apr-16	19,049	(2,671)	16,378	67.4187%	133,800	11,042	144,842	179	628	807	147,694
18	May-16	26,256	(3,319)	22,937	67.4187%	144,842	15,464	160,306	196	687	884	164,041
19	Jun-16	23,770	(3,324)	20,446	67.4187%	160,306	13,784	174,090	215	753	968	178,794
20	Jul-16	29,884	(4,081)	25,803	67.4187%	174,090	17,396	191,486	235	823	1,059	197,249
21	Aug-16	21,504	(3,111)	18,393	67.4187%	191,486	12,400	203,886	254	891	1,145	210,794
22	Sep-16	31,102	(4,292)	26,810	67.4187%	203,886	18,075	221,961	274	959	1,233	230,102
23	Oct-16	31,010	(4,208)	26,802	67.4187%	221,961	18,069	240,030	297	1,041	1,338	249,509
24	Nov-16	35,127	(4,385)	30,742	67.4187%	240,030	20,726	260,756	322	1,128	1,450	271,686
25	Dec-16	15,564	(2,405)	13,159	67.4187%	260,756	8,871	269,628	341	1,195	1,536	282,093
26	Jan-17	13,407	(2,485)	10,922	66.6244%	282,093	7,276	289,370	370	1,287	1,657	291,027
27	Feb-17	23,549	(3,590)	19,959	66.6244%	289,370	13,298	302,667	383	1,334	1,717	306,041
28	Mar-17	28,667	(4,310)	24,357	66.6244%	302,667	16,228	318,895	402	1,400	1,802	324,071
29	Apr-17	18,861	(3,166)	15,695	66.6244%	318,895	10,457	329,352	419	1,460	1,880	336,408
30	May-17	19,580	(3,486)	16,094	66.6244%	329,352	10,722	340,075	433	1,508	1,941	349,071
31	Jun-17	17,695	(3,333)	14,362	66.6244%	340,075	9,568	349,643	446	1,554	2,000	360,639
32	Jul-17	27,445	(4,062)	23,383	66.6244%	349,643	15,578	365,221	463	1,610	2,073	378,290
33	Aug-17	25,426	(4,321)	21,105	66.6244%	365,221	14,061	379,283	482	1,677	2,159	394,510
34	Sep-17	24,679	(3,862)	20,817	66.6244%	379,283	13,869	393,151	500	1,740	2,240	410,619
35	Oct-17	28,719	(4,439)	24,280	66.6244%	393,151	16,176	409,328	519	1,808	2,327	429,122
36	Nov-17	22,147	(3,645)	18,502	66.6244%	409,328	12,327	421,655	538	1,872	2,409	443,858
37	Dec-17	-	-	-	66.6244%	421,655	-	421,655	546	1,900	2,445	446,303
38	Jan-18	-	-	-	66.6244%	446,303	-	446,303	702 9/	2,011	2,712	449,016
39	Feb-18	-	-	-	66.6244%	446,303	-	446,303	702 9/	2,011	2,712	451,728
40	Mar-18	-	-	-	66.6244%	446,303	-	446,303	702 9/	2,011	2,712	454,441
41	Apr-18	-	-	-	66.6244%	446,303	-	446,303	702 9/	2,011	2,712	457,153
42	Total	$ 707,476	$ (101,844)	$ 605,632			$ 406,564		$ 11,658	$ 38,931	$ 50,589	

1/ McManeus Revised Supplemental Exhibit 1, Page 62. NC-1802(C), Column (a) plus Column (b).
2/ Maness Exhibit 1, Schedule 1-2, Column (e).
3/ Column (a) plus Column (b).
4/ NC Retail MWH at Generation Level factor from Public Staff Coal Ash DR 20-3.
5/ Amount in Column (g) of previous line, plus return for prior 12 months at beginning of each year.
6/ Column (c) times Column (d).
7/ Column (e) plus Column (f).
8/ Column (e) plus Column (g), divided by 2, times after tax cost of debt per NC-1803, divided by 12, unless footnoted otherwise.
9/ Column (e) plus Column (g), divided by 2, times after tax cost of debt based on 2018 income tax rates of 1.8872%, divided by 12.
10/ Column (e) plus Column (g), divided by 2, times after tax cost of equity per NC-1803, divided by 12.
11/ Column (h) plus Column (i).
12/ Column (g) plus total return for year to date from Column (j).

Maness Exhibit 1
Schedule 1-2

Duke Energy Carolinas
Docket No. E-7, Sub 1146
North Carolina Retail Operations
PUBLIC STAFF ADJUSTMENTS TO
TOTAL SYSTEM COAL ASH COSTS
For the Test Year Ended December 31, 2016
(in Thousands)

Line No.	Month	Disallowances Recommended by Public Staff Witness Moore 1/	Disallowances Recommended by Public Staff Witness Garrett 2/	Remove Costs of Extraction and Treatment of Contaminated Groundwater 3/	Removal of Selenium Removal Equipment 3/	Total Public Staff Adjustment 4/
		(a)	(b)	(c)	(d)	(e)
1	Dec-14	$ -	$ -	$ -	$ -	$ -
2	Jan-15	(23)	-	-	-	(23)
3	Feb-15	(190)	-	-	-	(190)
4	Mar-15	(412)	-	-	-	(412)
5	Apr-15	(855)	-	-	-	(855)
6	May-15	(2,903)	(143)	-	-	(3,046)
7	Jun-15	(1,793)	(444)	-	-	(2,237)
8	Jul-15	(2,440)	(798)	-	-	(3,238)
9	Aug-15	(344)	(695)	-	-	(1,039)
10	Sep-15	(2,029)	(763)	-	-	(2,792)
11	Oct-15	(2,409)	(589)	-	-	(2,998)
12	Nov-15	(1,719)	(331)	-	-	(2,050)
13	Dec-15	(2,296)	(363)	-	(132)	(2,791)
14	Jan-16	(1,889)	(549)	-	(330)	(2,768)
15	Feb-16	(1,495)	(494)	-	-	(1,989)
16	Mar-16	(2,137)	(782)	-	-	(2,919)
17	Apr-16	(1,950)	(721)	-	-	(2,671)
18	May-16	(2,688)	(626)	(5)	-	(3,319)
19	Jun-16	(2,433)	(889)	(2)	-	(3,324)
20	Jul-16	(3,059)	(758)	-	(264)	(4,081)
21	Aug-16	(2,201)	(902)	(8)	-	(3,111)
22	Sep-16	(3,184)	(964)	(12)	(132)	(4,292)
23	Oct-16	(3,174)	(963)	(71)	-	(4,208)
24	Nov-16	(3,596)	(771)	(18)	-	(4,385)
25	Dec-16	(1,593)	(755)	(57)	-	(2,405)
26	Jan-17	(1,372)	(1,062)	(51)	-	(2,485)
27	Feb-17	(2,411)	(1,151)	(28)	-	(3,590)
28	Mar-17	(2,935)	(1,350)	(25)	-	(4,310)
29	Apr-17	(1,931)	(1,198)	(37)	-	(3,166)
30	May-17	(2,004)	(1,456)	(26)	-	(3,486)
31	Jun-17	(1,811)	(1,508)	(14)	-	(3,333)
32	Jul-17	(2,809)	(1,241)	(12)	-	(4,062)
33	Aug-17	(2,603)	(1,586)	(132)	-	(4,321)
34	Sep-17	(2,526)	(1,271)	(65)	-	(3,862)
35	Oct-17	(2,940)	(1,357)	(142)	-	(4,439)
36	Nov-17	(2,267)	(795)	(583)	-	(3,645)
37	Dec-17	-	-	-	-	-
38	Jan-18	-	-	-	-	-
39	Feb-18	-	-	-	-	-
40	Mar-18	-	-	-	-	-
41	Apr-18	-	-	-	-	-
42	Total	$ (72,423)	$ (27,275)	$ (1,288)	$ (858)	$ (101,844)

1/ Based on recommendation of Public Staff witness Moore, allocated to individual months proportionately to total NC Spend.
2/ Public Staff Garrett Exhibit 5.
3/ Monthly amounts provided by Public Staff witness Junis.
4/ Sum of Columns (a) thru (d).