No. 477A20

SUPREME COURT OF NORTH CAROLINA

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STATE OF NORTH CAROLINA ex rel. UTILITIES COMMISSION, ATTORNEY GENERAL JOSHUA H. STEIN, PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION,	)	
Appellees,	)	
v.	)	From the North Carolina Utilities Commission
VIRGINIA ELECTRIC AND POWER COMPANY d/b/a DOMINION ENERGY NORTH CAROLINA,	)	
Appellant.	)	

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JOINT BRIEF OF INTERVENOR-APPELLEES PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION AND ATTORNEY GENERAL

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ISSUES PRESENTED

1. Did the Commission properly exercise its discretion when it allowed Dominion to recover its coal ash costs in a manner that reasonably balanced the interests of Dominion and its ratepayers?

2. Did the Commission deny Dominion equal protection of the laws when it allowed Dominion to recover its coal ash costs in a manner that reasonably balanced the interests of Dominion and its ratepayers?

INTRODUCTION

This Court recently decided an appeal from rate case determinations of the North Carolina Utilities Commission ("Commission") concerning coal ash cost recovery by Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC (together, "Duke"). *State ex rel. Utils. Comm'n v. Stein*, 375 N.C. 870, 851 S.E.2d 237 (2020) (*Stein*). The Utilities Commission's determination was affirmed, in part, and reversed and remanded, in part, in *Stein*. Subsequently, Duke agreed to reduce its recovery of coal ash costs in a settlement that addressed the remanded cases together with later Duke rate cases.

In this appeal, Dominion Energy North Carolina also challenges a Utilities Commission rate case determination about coal ash cost recovery. Dominion challenges the Utilities Commission's determination because the same approach to coal ash cost recovery was not allowed for Dominion as was allowed in the prior Duke cases that were appealed in *Stein*.

But Dominion's arguments ignore the modifications to Duke's cost recovery adopted in the settlement that was entered following this Court's decision in *Stein*. Dominion's arguments also ignore the terms of the stipulation approved in the earlier Dominion rate case that made it clear the approach in that case would not set a precedent or recommendation about how costs should be recovered in later cases.

Moreover, Dominion's arguments fail to recognize the legislative role that the Utilities Commission plays in ratemaking. The Utilities Commission is not bound by past precedent when it decides rate cases. Instead, its determinations take into account all of the facts and circumstances of the rate case and provide a reasoned explanation for its decisions.

Dominion's arguments also misapprehend the Utilities Commission's authority regarding a proposal that would allow extraordinary cost recovery pursuant to G.S. § 62-133(d). Dominion faults the Commission's determination because it took into consideration other material facts of record, and adopted an approach that shared the coal ash costs between

Dominion's ratepayers and its shareholders. Yet, that approach is fully consistent with the requirements in as explained in *Stein*.

Accordingly, as shown below, the decision of the Commission should be affirmed.

STATEMENT OF THE CASE AND FACTS

A. Dominion stores its coal ash in unlined ponds and landfills despite the risks.

Dominion is a public utility that provides northeastern North Carolina with electrical service generated from power plants that are mostly located in Virginia. For much of the twentieth century, Dominion primarily stored the coal ash generated by its coal-fired power plants in unlined ponds and landfills. (R p 168)

By the 1980s, however, it was becoming increasingly clear that coal ash could and in many cases was leaking from unlined ponds and contaminating groundwater and surface water. (R p 175) As early as 1979, for instance, the Environmental Protection Agency determined that coal ash ponds had "the potential for contributing directly to groundwater contamination." (R p 175) Similarly, in 1982, the Electric Power Research Institute also published a manual that reported that the "use of surface impoundments has fallen into disfavor" due to environmental and public health factors. (R p 175)

Indeed, given problems with its own coal ash in the 1980s, Dominion had reason to know that coal ash could contaminate groundwater. For example, in 1986 and 1988, the EPA ordered the cleanup of pollution caused by Dominion's coal ash in Virginia after contaminants leached into groundwater from coal ash placed in sand and gravel pits by a private contractor. (R pp 176-77) The contamination caused by Dominion's coal ash affected drinking water to such an extent that Dominion had to provide replacement water to residents who drew water from wells near its pits. (R p 177) Given problems like these across the industry, some electric utilities in the 1980s began using liners and operating leachate collection systems, and began monitoring groundwater to mitigate some of the harms associated with coal ash ponds. (R p 175)

Despite the utility industry's progress, however, Dominion continued to store much of its coal ash in unlined coal ash ponds and only installed groundwater monitoring wells after state regulators required it to do so. (R pp 175, 176) In 2017 and 2018 alone, 548 groundwater exceedances were reported at Dominion's coal ash ponds. (R p 177)

B. The regulation of coal ash is strengthened in response to industry mismanagement.

In 2015, the EPA adopted a new rule—commonly referred to as the CCR Rule—to address the "environmental contamination caused by [coal ash] surface impoundments." (R pp 179, 203) The CCR Rule implements federal standards to address the harms associated with coal ash storage, in particular groundwater and surface water contamination. Among other things, its standards concern "location restrictions, operating and design criteria (including dam safety and stability), closure and post-closure care, and groundwater monitoring and corrective action requirements." (R p 167) The CCR Rule requires Dominion to close its coal ash ponds, either by capping them in place, which requires the drainage of ponds and the installation of watertight caps, or by excavating and removing the coal ash, which entails drainage and the transfer of coal ash to lined, permitted landfills. (R pp 167-68)

Later, in 2019, Virginia's General Assembly responded to industry mismanagement of coal ash by enacting Senate Bill 1355. (R p 168) The legislation requires Dominion to excavate its ponds in the Chesapeake Bay watershed and recycle or dispose of its excavated coal ash in lined landfills.

(R p 168) While S.B. 1355 does not affect the coal ash costs at issue here, it will ultimately "result in an increase of the cost of closure." (R p 168)

C. Dominion recovers certain coal ash costs in 2016 based on a stipulation with the Public Staff.

When public utilities like Dominion would like to increase their rates, they must first seek permission to do so from the Commission, which has exclusive authority to set rates for the electricity that public utilities sell to their retail customers. *See* N.C. Gen. Stat. §§ 62-3(23), 62-32, 62-130, 62-134 (2020).

In 2016, Dominion filed an application to adjust its rates and charges for North Carolina retail consumers. *See* Virginia Electric & Power, No. E-22, Sub 532, slip op. 2016 N.C. PUC LEXIS 1183 (N.C. Utils. Comm'n Dec. 22, 2016). In that application, Dominion sought to recover $4.3 million in coal ash costs. *Id.* at 53.

In all Commission proceedings that affect utility rates or service, the Public Staff intervenes to defend the interests of the using and consuming public of North Carolina. N.C. Gen. Stat. § 62-15(d)(3). To resolve Dominion's 2016 application to adjust its rates, the Public Staff and Dominion agreed to a stipulation. Under the stipulation, Dominion was allowed to amortize its coal ash costs in equal installments and recover them from consumers in rates over five years, and to earn a return—that is, the financing costs—on the unamortized balance of the unrecovered costs. *Id.* at 62.

The stipulation between Dominion and the Public Staff, however, was expressly limited in scope. It provided, for instance, that (1) "the appropriate amortization period for future [coal ash] expenditures shall be determined on a case-by-case basis," that (2) the parties reserved the right to litigate how "reasonable and prudent [coal ash] expenditures incurred . . . after June 30, 2016 should be recovered in rates," and that (3) the parties' agreement regarding "deferral and amortization of [coal ash] expenditures incurred through June 30, 2016 shall not be construed as a recommendation that the Commission reach any conclusions . . . regarding any specific expenditures other than the ones to be recovered in this case." *Id.* at 57-58.

The Commission approved the stipulation. In its order, the Commission again reiterated the limited scope of the matters before it. It explained that its "approval of [Dominion's coal ash] cost deferral [was] based on the particular facts and circumstances presented in this docket and, therefore, [would not be] precedent for the treatment of [coal ash] costs in any future proceedings." *Id.* at 63. Echoing language in the stipulation, the Commission also indicated that its approval of the stipulation should not be "construed as determining the . . . prudence and reasonableness of any specific [coal ash] expenditures other than the ones deferred and authorized to be recovered in this case." *Id*. at 63.

D. Duke Energy seeks recovery of its coal ash costs.

In 2017, Duke Energy Progress ("Progress") and Duke Energy Carolinas ("Carolinas," and collectively with Progress, "Duke") submitted general rate case applications, seeking to recover certain of Duke's own coal ash costs. *See Stein* at 880-81, 851 S.E.2d at 244-45 (2020). The Public Staff, the Attorney General, and the Sierra Club intervened in Duke's rate cases and argued that the Commission should not allow Duke to recover all or some of its coal ash costs from ratepayers because, among other reasons, Duke's mismanagement of its coal ash had polluted groundwater and caused other harm. *Id*. at 886-887, 851 S.E.2d at 248-49.[1]

[1] Like the Public Staff, the Attorney General has authority to intervene in rate cases on behalf of the using and consuming public. N.C. Gen. Stat. §§ 62-20, 114-2(8)(a).

The Commission rejected intervenors' arguments and imposed a one-time $100 million mismanagement penalty on Duke that was much smaller than the disallowances that intervenors had sought. *Id.* at 882-99, 851 S.E.2d at 245-56. Otherwise, however, the Commission allowed Duke to recover its coal ash costs. For those costs that the Commission let Duke recover, Duke was allowed to amortize the costs over five years and earn a return on the unamortized balance. *Id.*

The Attorney General, the Public Staff, and the Sierra Club all appealed from the Commission's orders, contending, on somewhat different theories, that the Commission had erred when it allowed Duke to recover most of its coal ash costs and when it granted Duke a return on the unamortized balance. Last year, in December 2020, this Court resolved those appeals in *Stein*, partly affirming the Commission's orders, but also partly reversing them and accordingly remanding Duke's cases for further proceedings.

In its opinion, this Court first addressed the argument raised by some intervenors that Duke had incurred its coal ash costs unreasonably and imprudently and that the costs should therefore be disallowed under section 62-133(b) of the Public Utilities Act. Under that section, the Commission is required to disallow recovery of any costs that utilities have incurred unreasonably and imprudently. *See* N.C. Gen. Stat. § 62-133(b)(3). This Court held that the intervenors had, in large measure, not sufficiently identified and quantified the coal ash costs that they claimed Duke had incurred unreasonably and imprudently. *Stein* at 375 N.C. at 912, 851 S.E.2d at 264. As a result, this Court concluded that the Commission had not erred when it declined to disallow any of Duke's coal ash costs under that section of the Act. *Id.*

In addition, this Court held that the Commission could permissibly exercise its discretionary authority under section 62-133(d) of the Act to grant Duke a return on its coal ash costs. *Id.* at 926, 851 S.E.2d at 273. That section allows the Commission, when it sets rates, to consider all "material facts of record that will enable it to determine what are reasonable and just rates." N.C. Gen. Stat. § 62-133(d). This Court held that the Commission could rely on this provision to grant Duke a return because Duke had incurred its coal ash costs under unusual, complex, and extraordinary circumstances. *Stein* at 926, 851 S.E.2d at 273. Those circumstances, this Court explained, justified a departure from the traditional ratemaking rules in section 62-133(b) of the Act, including the traditional rule that utilities may only receive a return on property that is used and useful in providing current service to customers. *Id.*

This Court also held, however, that when the Commission had exercised its discretion under section 62-133(d) to allow Duke to defer and amortize its coal ash costs including a return on the unamortized balance, it had not properly considered "all of the material facts of record." *Id.* at 931-32, 851 S.E.2d at 276-77. Specifically, this Court faulted the Commission for its failure to consider all material facts of record when it rejected the Public Staff's "equitable sharing" proposal. The Public Staff had argued before the Commission that both Duke's shareholders and ratepayers should share the burden of Duke's coal ash costs, given Duke's past failure to comply with environmental laws in managing its coal ash and its failure to prevent environmental contamination, along with the fact that Duke's coal ash costs would not create new electrical generating capacity. *Id.* at 885-86, 895-96, 851 S.E.2d at 247, 254. Under the Public Staff's proposal, Duke would have been denied a return while it recovered its coal ash costs over approximately twenty-six years, resulting in shareholders and ratepayers both bearing approximately half of the costs. *Id.*

In its opinion, this Court held that the Commission had improperly rejected the Public Staff's proposal. The Commission had done so, this Court noted, because it had wrongly concluded that, in setting rates, it could not take into account "the nature and extent of any environmental violations that [Duke] may or may not have committed." *Id.* at 932, 851 S.E.2d at 277. This Court clarified that because the Commission had allowed Duke to recover coal ash costs outside of section 62-133(b)'s normal rules for ratemaking, the Commission was required to review *all* material facts of record in exercising its discretion to allow recovery, including "the extent to which [Duke had] committed environmental violations," even if "any such environmental violations did not result from imprudent management."[2] *Id.* at 931, 851 S.E.2d at 277. Thus, due to the Commission's failure to fully consider the Public Staff's equitable sharing proposal, this Court reversed the Commission and remanded Duke's cases for further proceedings. *Id.* at 947, 851 S.E.2d at 286.

[2] "[G]iven that the Commission decided to invoke its statutory authority to consider 'other facts' in determining the rates that should be established for the utilities, it was required to consider *all* material factors of record in making that determination . . . ." *Stein* at 931, 851 S.E.2d at 277 (emphasis in original).

Subsequently, the Public Staff, the Attorney General, and the Sierra Club entered into a settlement agreement with Duke. *See* Duke Energy Progress, No. E-2, Sub 1142, Duke Energy Carolinas, No. E-7, Sub 1146, slip. op. 2021 N.C. PUC LEXIS 723 (N.C. Utils. Comm'n Jun. 25, 2021) (Duke Remand Order). The settlement resolved coal ash recovery issues in the two cases that this Court remanded in *Stein*. It also resolved coal ash issues in two new rate cases that Duke had filed with the Commission while *Stein* was pending, and in any future rate cases that Duke files with respect to coal ash costs through 2030. The Commission has since approved the settlement in a series of orders entered in Duke's remanded and new rate cases. *Id.* at 5; *see also* Duke Energy Progress, No. E-2, Sub 1219, slip op. 2021 N.C. PUC LEXIS 435, (N.C. Utils. Comm'n April 16, 2021) (2021 Progress Rate Case Order); Duke Energy Carolinas, No. E-2, Sub 1214, slip op. 2021 N.C. PUC LEXIS 350 (N.C. Utils. Comm'n March 31, 2021).[3]

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[3] The Commission's orders approving the Duke settlement are included in the addendum to this brief. This Court can take judicial notice of those orders, just like it routinely takes judicial notice of the decisions of other courts and administrative bodies. *See, e.g.*, *State ex rel. Utilities Comm'n v. Southern Bell Tel. & Tel. Co.*, 289 N.C. 286, 288, 221 S.E.2d 322, 323 (1976) (taking judicial notice of Commission order).

The settlement adopted a combined approach that 1) leaves in place the cost recovery that the Commission granted Duke in the two cases that this Court remanded to the Commission, along with the $100 million mismanagement penalty, Duke Remand Order at 7; 2) reduces Duke's recovery of coal ash costs in Duke's new rate cases by $485 million, 3) reduces Duke's recovery in future rate cases by $270 million, *id.* at 8; and 4) reduces the return allowed during amortization in the new cases and future cases. *Id.* Thus, by reducing Duke's recovery in its later rate cases to offset its recovery in its earlier rate cases, the "combined effect" of the settlement in Duke's various rate cases achieves just and reasonable rates by sharing coal ash costs between Duke shareholders and ratepayers. *See* Progress 2021 Rate Case Order, Clodfelter, Comm'r, concurring and dissenting in part at 11-12.

Indeed, Duke has represented to the Commission that the net present value of the cost savings to North Carolina retail customers, including the applicable return, is in excess of $900 million during the period covered by the settlement. Duke Remand Order at 9. Accordingly, under the settlement, Duke's shareholders will now bear a share of Duke's coal ash costs that is substantially larger than what they would have borne if the only disallowance that Duke incurred had been the one-time $100 million penalty that the Commission initially ordered.

E. Dominion again seeks recovery of its coal ash costs.

In 2019, after the Duke orders had been appealed but before this Court resolved the appeals, Dominion submitted another application for a general rate increase. (R p 83) In total, Dominion requested a $26,958,000 increase in its non-fuel base rates and charges for its North Carolina retail customers. (R p 86)[4] A significant portion of Dominion's requested rate increase stemmed from its coal ash costs: between July 1, 2016 and June 30, 2019, Dominion had incurred an estimated $390.4 million in such costs, of which $21.8 million were allocable to North Carolina retail customers. (R p 166) In its application, Dominion requested that it again be allowed to recover these costs over five years and receive a return on the unamortized balance.

Dominion and the Public Staff did not reach a stipulation about the treatment of coal ash costs in the 2019 case. (R p 98) The Public Staff proposed that Dominion's shareholders and ratepayers should share the burden of Dominion's coal ash costs given Dominion's culpability for

[4] Later filings by Dominion had the effect of reducing its rate increase to $24,195,000. (R p 86)

environmental contamination and based on the magnitude and nature of the costs. (R p 174-75) Under the Public Staff's equitable sharing proposal, Dominion would have been denied a return while it recovered its coal ash costs over approximately 19 years. (R p 185)

In February 2020, the Commission issued an order that partially granted Dominion's request for a rate increase. (R pp 72-238) The Commission allowed Dominion to recover its coal ash costs. It also allowed Dominion to recover the financing costs associated with its coal ash costs from the time those costs were first incurred up until its new rates became effective. But after that effective date, the Commission declined to let Dominion receive a return on the unamortized balance of the costs while they were being recovered. And it further held that Dominion should recover its costs over ten years, not five as requested by Dominion or 19 as recommended by the Public Staff. (R p 95)

In explaining its decision, the Commission initially noted that its 2016 decision that had allowed Dominion to recover its coal ash costs with a return over five years was not intended to have precedential value, given the stipulation between Dominion and the Public Staff in that rate case. (R p 203) It also explained that its prior order lacked precedential value because there was less evidence in that case on the "industry's and [Dominion's] historical [coal ash] practices and decisions." (R p 203)

The more developed evidentiary record in this case, however, weighed heavily in the Commission's assessment of the proper treatment of Dominion's coal ash costs. In its order, the Commission noted that no party had challenged the prudence of Dominion's specific coal ash costs, and for that reason, the Commission held that Dominion's coal ash costs were prudently incurred. (R pp 205, 209-210) Nonetheless, the Commission concluded that "[a] number of material facts in evidence call[ed] into question the prudence of [Dominion's] actions and inaction and the risk accepted by [Dominion] management at several of its [coal ash] sites." (R p 212) That evidence included:

- Dominion's past belief that using unlined ponds and then closing them in place without removing contaminated water provided a permanent disposal solution for coal ash;
- Dominion's almost complete failure to develop written analyses, cost-benefit analyses, or reports on alternative storage options with respect to coal ash; and

- A number of industry and government studies that provided evidence of industry best practices related to the management and disposal of coal ash, which Dominion had failed to follow.

(R pp 206-09) Based on this and other evidence, the Commission concluded that Dominion's management of coal ash, and the risks that its management accepted, were "material facts of record" that the Commission had to consider when setting just and reasonable rates. (R p 212)

Given these material facts of record, the Commission concluded that denying Dominion a return on its coal ash costs was necessary "to strike a fair and reasonable balance" between ratepayers and shareholders. (R p 214) In addition to the material facts concerning Dominion's risky management of its coal ash discussed above, a number of other material facts persuaded the Commission to deny a return. The Commission noted that this approach was consistent with its denial of a return in prior cases where utilities had sought to recover large costs from consumers, like the cost of building nuclear plants that were later abandoned, and the cost of remediating pollution caused by manufactured natural gas plants. (R pp 210-11) The Commission also noted, among other things, the inequity of requiring current ratepayers to bear all coal ash costs when those costs largely stemmed from electric service provided to past ratepayers. (R p 211)

The Commission also determined that allowing Dominion to recover its costs over ten years instead of five was appropriate. It found that a ten-year period struck a "more appropriate and fairer balance" and was also in line with its "historical treatment of major plant cancellations." (R p 215) Based on these considerations and others, the Commission determined that "[Dominion's] proposed five-year amortization period [did] not achieve a fair balance in light of the evidence in the record, the magnitude and the nature of the costs involved and the rate impact to customers." (R p 215)

After the Commission ruled, Dominion moved the Commission to reconsider its decision, again asking the Commission to let it recover its costs over five years with a return. (R pp 265-80) In its motion, Dominion argued that the Commission's ratemaking treatment of Dominion was inconsistent with the 2016 Dominion order that was based on a stipulation, and with the 2018 Duke orders that the Public Staff and Attorney General had appealed. (R pp 285-86) The Commission rejected these arguments, explaining that its orders in rate cases "are not *res judicata*" and do not fall "within the doctrine of *stare decisis*." (R p 288 (emphasis removed)) The

Commission also reiterated that its decision was based on competent, material, and substantial evidence. (R pp 288, 289-90)

Dominion then appealed to this Court. (R pp 294-304) After it filed its notice of appeal and exceptions, this Court reversed in part the 2018 Duke orders on which Dominion has largely premised this appeal. *See Stein*, 375 N.C. at 947, 851 S.E.2d at 286. Subsequently, Duke agreed in its settlement regarding the coal ash costs at issue in multiple Duke rate cases and through 2030, that its shareholders would bear a substantially larger amount in costs than the $100 million penalty the Commission had originally ordered in its 2018 Duke orders. *See supra* pp 15-16.

SUMMARY OF THE ARGUMENT

Dominion appeals on two grounds.

First, Dominion argues that the Commission's decision was arbitrary and capricious for allowing the recovery of the coal ash costs by amortizing them over ten years with no return on the unamortized balance instead of by allowing the same recovery allowed in prior cases; i.e., by amortizing costs over five years and allowing a return on the unamortized balance. To the contrary, however, the Commission is not bound to adopt the same ratemaking approach in this case as was allowed in prior cases. Moreover, Dominion's comparison to the ratemaking treatment in particular prior cases is not well supported given the limited scope of the prior Dominion case and the changes ultimately adopted in settlement of the Duke cases.

The Commission's determination below reflected fair and careful consideration of all facts and circumstances and displayed a reasoned judgment. The Commission exercised its discretion under section 62-133(d) of the Public Utilities Act, and complied with the standards set out by this Court in *Stein* with ample support for the approach that was approved for the recovery of extraordinary costs outside of the parameters of normal ratemaking rules, fairly balancing the interests of ratepayers and shareholders.

Dominion's second argument, that it was denied equal protection, is baseless. When considered in light of Duke's comprehensive settlement of its coal ash costs, Dominion cannot claim that Duke received preferential treatment.

For these reasons, the decision of the Commission should be affirmed.

ARGUMENT

Standard of Review

This Court reviews the Commission's decisions to determine whether they are:

(1) In violation of constitutional provisions,

(2) In excess of statutory authority or jurisdiction of the Commission,

(3) Made upon unlawful proceedings,

(4) Affected by other errors of law,

(5) Unsupported by competent, material and substantial evidence in view of the entire record as submitted, or

(6) Arbitrary or capricious.

N.C. Gen. Stat. § 62-94(b); *see also State ex rel. Utils. Comm'n v. Pub. Staff-N.C. Utils. Comm'n*, 322 N.C. 689, 698, 370 S.E.2d 567, 573 (1988) (reviewing decision under section 62-94).

The Commission's conclusions of law are reviewed de novo. *State ex rel. Utils. Comm'n v. N.C. Waste Awareness & Reduction Network*, 255 N.C. App. 613, 615, 805 S.E.2d 712, 714 (N.C. Ct. App. 2017), *aff'd per curiam*, 371 N.C. 109, 812 S.E.2d 804 (2018).

Its findings of fact are reviewed to determine whether they are supported by "competent, material and substantial evidence." *State ex rel. Utils. Comm'n v. Cooper*, 367 N.C. 444, 448, 761 S.E.2d 640, 643 (2014).

Its decisions can also be reversed as arbitrary or capricious if they "fail to display a reasoned judgment." *State ex rel. Utils. Comm'n v. Piedmont Nat. Gas Co.*, 346 N.C. 558, 573, 488 S.E.2d 591, 601 (1997).

Discussion of Law

I. The Commission Properly Exercised Its Discretion Under Section 62-133(d) in Setting a Ten-Year Amortization Period and Denying Dominion a Return on Its Unamortized Coal Ash Costs.

The Commission properly exercised its discretion under section 62-133(d) of the Public Utilities Act when it allowed Dominion to recover its coal ash costs over ten years without a return.

In *Stein*, this Court articulated a four-part test to assess whether the Commission has properly exercised its discretion to allow recovery of costs outside of the parameters of normal ratemaking rules. Specifically, it held that the Commission may employ section 62-133(d) in situations involving:

1. "unusual, extraordinary, or complex circumstances that are not adequately addressed in the traditional ratemaking procedures set out in [section] 62-133,"

2. “in which the Commission reasonably concludes that these circumstances justify a departure from the ordinary ratemaking standards set out in [section] 62-133,” and

3. “determines that a consideration of these ‘other facts’ is necessary to allow the Commission to fix rates that are just and reasonable to both the utility and its customers,” and then

4. “makes sufficient findings of fact and conclusions of law supported by substantial evidence in light of the whole record explaining why a divergence from the usual ratemaking standards would be appropriate and why the approach that the Commission has adopted would be just and reasonable to both utilities and their customers.”

375 N.C. at 926, 851 S.E.2d at 273.

Here, Dominion does not appear to challenge the Commission’s decision to diverge from traditional ratemaking principles in allowing it to recover its coal ash costs through deferral and amortization. Accordingly, the first three parts of the *Stein* test are not at issue in this case.

Dominion instead seems to argue that the Commission did not make "sufficient findings of fact and conclusions of law . . . explaining why . . . the approach that the Commission has adopted would be just and reasonable to both utilities and their customers." *Id.* Dominion specifically argues that the Commission's order must be reversed due to its supposed failure to adequately distinguish its treatment of Dominion's coal ash costs in the rate case below from the "precedent" that it set in its 2016 Dominion order and its 2018 Duke orders.

Dominion maintains that the Commission supposedly "failed to set forth *any* facts to support its break with its own precedent" when the Commission, in contrast to its rulings in the 2016 Dominion and 2018 Duke rate cases, denied Dominion a return and allowed recovery of its coal ash costs over ten years instead of five. Dom. Br. at 14, 11 (emphasis in original). According to Dominion, the "question before this Court is whether the Commission erred by exercising its discretion differently and to the detriment of [Dominion] in this case *after* exercising it to the benefit of Duke Energy and previously to [Dominion] when faced with similar facts." *Id.* at 16 (emphasis in original).

Dominion's argument fails because, as discussed below, the Commission is not bound by *stare decisis* when it engages in ratemaking. As a result, it need only provide a reasoned explanation for its decisions, and it has more than satisfied that requirement here.

A. The Commission exercises a legislative function when setting rates and is therefore not bound by prior decisions.

As an initial matter, the Commission's ratemaking authority is not limited by principles of *res judicata* or *stare decisis*.

This Court has explained that the Commission's ratemaking authority "is a legislative rather than a judicial function," and that in "fixing rates . . . the Commission [exercises] a function delegated to it by the legislative branch of government." *State ex rel. Utils. Com. v. Thornburg*, 325 N.C. 463, 469, 385 S.E.2d 451, 454 (1989) (holding that because the Commission was exercising a legislative function, its treatment of nuclear cancellation costs in previous rate cases was not governed by the principle of *res judicata*). As a result, *stare decisis* does not apply to the Commission when it engages in the legislative function of ratemaking. *See, e.g.*, *State ex rel. Utils. Com. v. Carolina Util. Customers Ass'n,* 348 N.C. 452, 472, 500 S.E.2d 693, 706 (1998)

("A final order of the [Commission] in a general rate case is not within the doctrine of *stare decisis*.").

Because the Commission exercises a legislative function in ratemaking and is not bound by *stare decisis* and *res judicata* principles as to its past decisions, it may vary its policies based on the particular facts presented in the case. *See State ex rel. Utils. Comm'n v. Carolina Water Serv*., 225 N.C. App. 120, 131, n. 6, 738 S.E.2d 187, 194, n. 6 (2013). In doing so, the Commission is generally required to provide a reasoned explanation for its decisions. *Id* at 130, 738 S.E. 2d at 194; *State ex rel. Utils. Comm'n v. Nantahala Power & Light Co*., 326 N.C. 190, 199-200, 388 S.E.2d 118, 124 (1990).

Dominion cites a number of federal cases to support its contention that "the Commission cannot 'arbitrarily' disregard its own precedent." Dom. Br. at 33, 33-35. It describes these cases as holding that agencies cannot "depart, without explanation, from precedent." *Id.* at 34. Here, however, as shown below, the Commission provided a sufficient explanation for its departure from its past treatment of coal ash costs.

B. The Commission's order sufficiently explains its departure from its past treatment of coal ash costs.

In its order, the Commission provided a detailed explanation for its decision to "reasonably balance" the burdens of Dominion's coal ash costs by sharing them between Dominion's shareholders and its ratepayers. It explained that its decision to allow Dominion to recover its coal ash costs over ten years without a return was based on, among other things, (1) the Commission's similar treatment of past requests to recover large, extraordinary costs, (2) Dominion's risky management of its coal ash, (3) the unfairness of requiring Dominion's current ratepayers to bear costs associated with generating electricity used by past ratepayers, and (4) Dominion's failure to seek recovery for closure and removal of its coal ash facilities in prior rate cases. (R pp 210-12, 217-23)

i. The Commission explained that its decision was in keeping with its past treatment of extraordinary, large costs.

As an initial matter, the Commission explained that its decision was justified because it had treated prior requests by utilities to recover large, extraordinary costs in a similar fashion.

The Commission discussed three cases that demonstrated its "well-established history of allocating prudently incurred costs, specifically in the context of extraordinary, large costs such as environmental clean-up and plant cancellation, between ratepayers and shareholders in order to strike a fair and reasonable balance." (*Id.* at 210-11) The Commission explained that although the costs at issue in those cases were prudently incurred, the Commission had concluded that fairness nonetheless dictated a sharing of costs. (*Id.*) The Commission further explained that in those cases, it had achieved a sharing of costs by amortizing the costs and by denying a return on the unamortized balance. (*Id.*)

In applying this history to the present case, the Commission found that the recovery that Dominion seeks here would have a marked effect on customer rates: Dominion would ask each of its customers to pay an additional $179 annually in rates for coal ash costs. (*Id.*) It concluded that, as in prior cases involving extraordinary and large costs, it would be inequitable to place the entirety of Dominion's coal ash costs on its shareholders, but likewise ratepayers alone should also not "bear the entire risk, and the rate impact, associated with [Dominion's coal ash] liabilities." (*Id.* at 211)

Dominion argues that in its 2016 Dominion order, "the Commission held that the extraordinary nature of these costs *supported* [Dominion's] ability to earn a return," and that the Commission supposedly provided no basis for changing its position. Dom. Br. at 24 (emphasis in original). Dominion likewise argues that "[i]t was arbitrary and capricious for the Commission to rely on its historical treatment of nuclear cancellation costs . . . rather than rely on its more recent and applicable precedent involving 'identical' coal ash costs." *Id.* at 19. Again, however, the Commission's ratemaking authority is not bound by *stare decisis*. *See, e.g.*, *Carolina Utilities Customers Ass'n,* 348 N.C. at 472, 500 S.E.2d at 706. As a result, it may vary its policies to address the facts and circumstances of the case as long as it provides a rationale for doing so, as it has here.

ii. The Commission explained that Dominion's failures in managing its coal ash justified its decision.

The Commission also explained that Dominion's failures in managing its coal ash justified its decision.

In its order, the Commission explained that while Dominion had made a prima facie case that the coal ash expenditures at several of its sites were prudently made, the evidence presented by the Public Staff and the facts provided by Dominion "highlight[ed] the risks taken by [Dominion] with respect to its historical management of its [coal ash] liabilities and call[ed] into question [Dominion's] prudence." (R p 206) The Commission then discussed the evidence in the record that led it to this conclusion, as well as a series of industry and government studies that provided evidence of industry best practices related to the management and disposal of coal ash. (*Id.* at 206-09) While the Commission found that Dominion's coal ash costs were prudently incurred and that it would therefore be inequitable to place the entirety of those costs on Dominion's shareholders, it also found that ratepayers should not bear the entire rate impact associated with the coal ash liabilities. This was because "[a] number of material facts in evidence call into question the prudence of [Dominion's] actions and inaction and the risks accepted by [Dominion] management at several of its [coal ash] sites." (*Id.* at 212)

Dominion argues that the Commission "erroneously relied on its inability to resolve the issue of historical prudency as the basis for allocating costs between ratepayers and [Dominion's] shareholders through denial of a return." Dom. Br. at 23. Dominion further argues that "the Commission's indecision about [Dominion's] prudency is not a factual finding," and that the Commission, "under the guise of considering 'other facts,' supplanted the prudency framework." *Id*. According to Dominion, "[t]he Commission arbitrarily and unlawfully created a separate, lower standard as a backdoor to disallow prudently incurred costs." *Id*. at 24.

This Court, however, has already rejected Dominion's argument that the Commission cannot order that costs be shared among ratepayers and shareholders unless specific costs are disallowed for imprudence. In *Stein*, this Court *reversed* the Commission because, in exercising its discretion to allow Duke to recover its coal ash costs, the Commission had failed to consider "the extent to which [Duke had] committed environmental violations." 375 N.C. at 931, 851 S.E.2d at 276-77. This Court concluded that the issue was material even if "any such environmental violations did not result from imprudent management." *Id.*

Dominion's argument seeks reversal of the Commission's decision for doing precisely what this Court demanded in *Stein*.

iii. The Commission explained that its decision was justified by the need to ensure that current ratepayers not bear excessive costs associated with past service.

The Commission next explained that its decision was justified by the "matching principle," which "dictates that customers who use an asset should pay for the asset at the time it is used." (R p 202)

The Commission explained that it "endeavors to avoid or minimize the extent to which present and future customers pay for costs incurred related to service provided in the past." (*Id.*) That practice is based on this Court's recognition that the Public Utilities Act is designed to ensure that ratepayers generally only bear "the cost of service attributable to [the] period" during which they actually used electrical service. *State ex rel. Utils. Comm'n v. Edmisten*, 291 N.C. 451, 470, 232 S.E.2d 184, 195 (1977).

Here, the Commission noted that the coal ash costs at issue were related to electric service provided to customers in the past and concluded that assigning all coal ash costs to present and future ratepayers would violate the matching principle. The Commission therefore viewed these considerations to be "material facts of record" that were relevant for "striking the appropriate balance between shareholder and customer interests to set just and reasonable rates." (R p 212)

iv. The Commission explained that its decision was justified by Dominion's past failure to recover its coal ash costs over the lives of its coal-fired plants.

Finally, the Commission explained the related point that its decision was justified by Dominion's failure to recover its coal ash costs during the useful lives of its coal-fired power plants.

The Commission referred to one of its prior orders, where it had explained that the costs of retiring an asset should be recovered over the useful life of the asset. (*Id.* at 220-21) The Commission in that order concluded that this practice "properly assigns costs to those ratepayers receiving benefit for the asset while in service." (*Id.* at 221)

Here, the Commission explained, Dominion had failed to heed that principle, by not seeking recovery of the costs of closure of its coal ash storage facilities over the useful lives of its coal-fired plants. The Commission noted that a 2004 industry report had made it "clear that the costs of closure of coal ash disposal facilities could likely range well into the tens of millions of dollars." (*Id.* at 219)

Based on these considerations, the Commission concluded that its treatment of Dominion's coal ash costs was "further supported by the failure of [Dominion] to properly account for the full decommissioning costs of its coal-fired power plants" and recover those costs in past cases. (*Id.* at 223)

v. The Commission adequately explained its divergence from the ratemaking treatment that it adopted in its 2016 Dominion order and 2018 Duke orders.

Dominion argues that, despite the Commission's extensive explanation for why it was allowing Dominion to recover its costs over ten years without a return, the Commission's order must be reversed. That is so, Dominion claims, because the Commission did not distinguish the "clear precedent" that the Commission supposedly set in its 2016 Dominion order and its 2018 Duke orders for amortizing coal ash costs over five years and allowing a full return on the unamortized balance. Dom. Br. at 37.

First, Dominion is simply mistaken that the Commission "provided no reasoned basis for departing from" its 2016 Dominion order. *Id.* at 18. The Commission expressly noted that its 2016 order did "not have precedential value with respect to the [coal ash] issues in this case" because it was premised on a stipulation between Dominion and the Public Staff. (R p 202) That stipulation, the Commission observed, had provided that it should not be viewed "as a recommendation that the Commission reach any conclusions regarding the prudence and reasonableness of [Dominion's] overall [coal ash] plan, or regarding any specific expenditures other than the ones to be recovered" there. (*Id.*)

Furthermore, the Commission also explained that the evidence that it had considered in Dominion's 2016 rate case was "far less extensive" than the evidence before it in the present case, and that "the issues of prudence and reasonableness were [therefore] not fully litigated and no significant evidentiary record was developed." (*Id.* at 203)[5] The Commission further explained that its decisions "must be based on competent, material and substantial evidence in the record of the instant proceeding," and concluded that, as a result of having had far less extensive evidence in the record in the prior rate case, "it would be inappropriate to give [its 2016 Dominion order] precedential effect for the treatment of costs [Dominion] is seeking to recover in this proceeding." (*Id.*) Accordingly, Dominion's claim that the

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[5] The record in the proceeding that resulted in the 2016 Dominion order was less extensively developed in part due to the relatively small amount of cost recovery that Dominion sought in that case. There, Dominion only asked to recover $4,417,000 of deferred coal ash costs. *See* 2016 Dominion order at 60, 62. Here, in contrast, Dominion seeks recovery with respect to $377 million in costs, of which $21.8 million are allocable to North Carolina customers. (R p 166) The Commission noted that the recovery that Dominion seeks here would require customers to pay an additional $179 annually in rates for coal ash costs. (*Id.* at p 212)

Commission "provided no reasoned basis for departing from" its 2016 Dominion order is meritless. Dom. Br. at 17-18.

Second, with respect to the 2018 Duke orders, Dominion is correct that the Commission did not expressly distinguish those orders, which were still on appeal before this Court when the Commission ruled below. Nonetheless, the Commission's extensive explanation for its treatment of Dominion's coal ash costs, described above, provided an adequate explanation for why it broke with the different policy that it had adopted in the 2018 Duke orders.

In any event, even if the Commission's failure to expressly distinguish its 2018 Duke orders could be error in other circumstances, it certainly is not error here. After the Commission issued the order that is under review in this appeal, this Court reversed the 2018 Duke orders in *Stein* because the Commission had not adequately considered a proposal by the Public Staff, which is similar to the ratemaking treatment that the Commission adopted in the present case. 375 N.C. at 931-32, 851 S.E.2d at 276-77. Later, moreover, Duke also agreed to settle multiple rate cases on terms that were markedly less favorable for Duke than the ratemaking treatment that the Commission adopted in its earlier Duke orders. Dominion's request is utterly without merit when it asks this Court to reverse the order below because the Commission failed to replicate its treatment of Duke's coal ash costs in two orders that this Court later reversed, and that Duke later resolved as part of a comprehensive settlement on different terms less favorable to Duke.

In these unusual circumstances, even if the Commission erred, reversal of the order below and remand would serve no purpose. That is so because there is now no need for the Commission to distinguish the ratemaking treatment that it afforded Duke that was later reversed and superseded. This Court has long held that, even when there is error, if a remand to correct the error "would be futile," then the decision below should be affirmed. *Arnold v. Ray Charles Enterprises, Inc.*, 264 N.C. 92, 99, 141 S.E.2d 14, 19 (1965).

Here, too, even if the Commission erred by failing to expressly distinguish the 2018 Duke orders, that error does not entitle Dominion to relief. Dominion's argument that the Commission's failure to distinguish the 2018 Duke orders requires reversal is therefore baseless.

C. Dominion's remaining statutory arguments are meritless.

Dominion also advances several additional arguments to try to show that the Commission acted arbitrarily when it ordered a "reasonable balancing" of Dominion's coal ash costs. These arguments, however, are just as meritless as Dominion's assertion that the Commission failed to provide a rationale for diverging from the policy that it adopted in its prior orders.

Dominion first contends that the Commission erred by not holding, as it did in its 2016 order, that Dominion's coal ash costs were "property used and useful" and, on that basis, granting Dominion a return on its coal ash costs. Dom. Br. at 24-25.

As an initial matter, even if Dominion's coal ash costs *were* used and useful, that point would provide no basis for reversing the order below. In *Stein*, this Court recognized that section 62-133(b)'s command that the Commission grant a return only on used and useful property does not apply where, as here, the Commission exercises its discretion to award recovery under section 62-133(d). 375 N.C. at 925-26, 851 S.E.2d at 272-73. In this context, what matters is instead whether the Commission has explained sufficiently "why the approach that [it] has adopted would be just and reasonable to both utilities and their customers." *Id.* at 926, 851 S.E.2d at 273. Here, as shown above, it has done so.

And in any event, even if that were relevant, the Commission had more than adequate grounds to conclude that Dominion's coal ash costs were not spent on used and useful property: the Commission found compelling the testimony of Dominion's own witness that, but for accounting requirements, approximately 98% of Dominion's coal ash costs would have been booked as operating expenses that would ordinarily not receive a return. (R p 214)

Dominion also argues that the Commission's denial of a return during the amortization period was arbitrary, because the Commission let Dominion recover the financing costs it incurred to support its coal ash spending during the deferral period before its new rates became effective. Dom. Br. at 26-27. [6]

Given the thoroughly reasoned explanation of the Commission's decision to deny a return during amortization and the relatively brief explanation supporting financing costs during deferral, a better argument could be that the Commission arbitrarily allowed the recovery of financing costs during the deferral period.[7] Dominion is mistaken that the

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[6] Before the Commission, the Public Staff did not oppose the recovery of financing costs during the deferral period, while the Attorney General did oppose this recovery.

[7] See the dissent of Commissioner Clodfelter on the issue of financing costs during the deferral period where he states, in part, "With respect to the allowance of what the Commission calls 'financing costs,' however, I can find no supportable basis for differentiating the Deferral Period from the amortization period." (*Id.* at 233-35)

Commission's decision to allow Dominion to recover its financing costs before recovery undermines its decision to deny a return later.

Lastly, Dominion repeatedly suggests throughout its brief that in *Stein*, this Court holds that the only appropriate ratemaking treatment of coal ash costs is amortizing costs over five years and awarding a return on the unamortized balance. *See, e.g.*, *id*. at 15, 19-20, 29. This claim is also unsupported and meritless. In *Stein*, this Court *reversed* the Commission for erroneously failing to consider the Public Staff's equitable sharing proposal, a proposal that would have required Duke to recover its coal ash costs over a quarter of a century without a return on the unamortized balance. 375 N.C. at 931-32, 851 S.E.2d at 276-77. Nothing in *Stein* suggests that the Commission lacked authority to deny Dominion a return and allow it to recover its costs over ten years instead of five.

Accordingly, like Dominion's argument that the Commission failed to provide a rationale for not following its prior orders, its other arguments are baseless as well.

II. The Commission Did Not Deny Dominion Equal Protection of the Laws.

Dominion finally argues that the Commission's different treatment of Duke and Dominion denies it equal protection of the laws under the U.S. and North Carolina Constitutions. Dom Br. at 37-39. This constitutional argument, however, is just as meritless as its statutory arguments.

This Court has repeatedly held that economic regulations, including the Commission's ratemaking decisions, should be upheld against equal-protection challenges so long as they are rationally related to a legitimate government purpose. *In re North Carolina Pesticide Bd. File Nos. IR94-128, IR94-151, IR94-155*, 349 N.C. 656, 674-75, S.E.2d 165, 177 (1998).[8] If any conceivable basis for a decision exists, it should be upheld as rational. *Rhyne v. K-Mart Corp.*, 358 N.C. 160, 181-83, 594 S.E.2d 1, 16 (2004). Moreover, even when the Commission in its orders could have drawn "finer distinctions" among differently situated regulated entities, its decisions should still be upheld, because equal protection does not require the Commission "to solve all aspects of an economic dilemma at once." *Edmisten*, 294 N.C. at 612, 242

[8] *See also Dennis v. Duke Power Co.*, 341 N.C. 91, 102, 459 S.E.2d 707, 714 (1995); *Nantahala Power*, 326 N.C. at 204, 388 S.E.2d at 126-27; *State ex rel. Utils. Comm'n v. Edmisten*, 294 N.C. 598, 611, 242 S.E.2d 862, 870-71 (1978).

S.E.2d at 871. The Commission can instead "proceed one step at a time to overcome such problems," such as finding the proper balance in sharing costs between ratepayers and shareholders. *Id*.

Here, Dominion apparently argues that it is similarly situated with Duke, and that as a result, no rational basis could possibly exist that could justify the relatively preferential treatment that Duke received in its 2018 rate cases compared to the treatment Dominion received below. Dom Br. at 39. For instance, Dominion observes that while the Commission disallowed 26% of its coal ash costs below, the Commission only disallowed 13% of Duke's costs in 2018 through its mismanagement penalty. *Id.* at 32.

After Dominion filed this appeal, however, the 2018 Duke orders that Dominion complains about were, in relevant part, reversed on appeal and remanded. Later, moreover, after Dominion filed its opening brief, Duke agreed in the settlement of multiple rate cases that its shareholders should bear a share of its coal ash costs substantially larger than what the Commission initially ordered be imposed as the penalty in its 2018 Duke orders. *See supra* pp 15-16, 21. Thus, the basis for Dominion's argument that the Commission granted preferential treatment to Duke, and thereby denied it equal protection, has simply disappeared.

Dominion's constitutional arguments are therefore just as baseless as its statutory arguments.

CONCLUSION

The Public Staff and the Attorney General respectfully request that this Court affirm the Commission's order below in all respects.

This 6th day of August, 2021.

PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

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CONTENTS OF APPENDIX

§ 62-3. Definitions.

As used in this Chapter, unless the context otherwise requires, the term:

(1) "Broadband service" means any service that consists of or includes a high-speed access capability to transmit at a rate of not less than 200 kilobits per second in either the upstream or downstream direction and either (i) is used to provide access to the Internet, or (ii) provides computer processing, information storage, information content, or protocol conversion, including any service application or information service provided over such high-speed access service. "Broadband service" does not include intrastate service that was tariffed by the Commission and in effect as of the effective date of this subdivision.

(1a) "Broker," with regard to motor carriers of passengers, means any person not included in the term "motor carrier" and not a bona fide employee or agent of any such carrier, who or which as principal or agent engages in the business of selling or offering for sale any transportation of passengers by motor carrier, or negotiates for or holds himself, or itself, out by solicitation, advertisements, or otherwise, as one who sells, provides, furnishes, contracts, or arranges for such transportation for compensation, either directly or indirectly.

(1b) "Bus company" means any common carrier by motor vehicle which holds itself out to the general public to engage in the transportation by motor vehicle in intrastate commerce of passengers over fixed routes or in charter operations, or both, except as exempted in G.S. 62-260.

(2) "Certificate" means a certificate of public convenience and necessity issued by the Commission to a public utility or a certificate of authority issued by the Commission to a bus company.

(3) "Certified mail" means such mail only when a return receipt is requested.

(4) "Charter operations" with regard to bus companies means the transportation of a group of persons for sightseeing purposes, pleasure tours, and other types of special operations, or the transportation of a group of persons who, pursuant to a common purpose and under a single contract, and for a fixed charge for the vehicle, have acquired the exclusive use of a passenger-carrying motor vehicle to travel together as a group to a specified destination or for a particular itinerary, either agreed upon in advance or modified by the chartered group after having left the place of origin.

(5) "Commission" means the North Carolina Utilities Commission.

(6) "Common carrier" means any person, other than a carrier by rail, which holds itself out to the general public to engage in transportation of persons or household goods for compensation, including transportation by bus, truck, boat or other conveyance, except as exempted in G.S. 62-260.

(7) "Common carrier by motor vehicle" means any person which holds itself out to the general public to engage in the transportation by motor vehicle in intrastate commerce of persons or household goods or any class or classes thereof for compensation, whether over regular or irregular routes, or in charter operations, except as exempted in G.S. 62-260.

(7a) "Competing local provider" means any person applying for a certificate to provide local exchange or exchange access services in competition with a local exchange company.

(8), (9) Repealed by Session Laws 1995, c. 523, s. 1.

(9a) "Fixed route" means the specific highway or highways over which a bus company is authorized to operate between fixed termini.

(10) "Foreign commerce" means commerce between any place in the United States and any place in a foreign country, or between places in the United States through any foreign country.

(11) "Franchise" means the grant of authority by the Commission to any person to engage in business as a public utility, whether or not exclusive or shared with others or restricted as to terms and conditions and whether described by area or territory or not, and includes certificates, and all other forms of licenses or orders and decisions granting such authority.

(12) "Highway" means any road or street in this State used by the public or dedicated or appropriated to public use.

(13) "Industrial plant" means any plant, mill, or factory engaged in the business of manufacturing.

(14) "Interstate commerce" means commerce between any place in a state and any place in another state or between places in the same state through another state.

(15) "Intrastate commerce" means commerce between points and over a route or within a territory wholly within this State, which commerce is not a part of a prior or subsequent movement to or from points

outside of this State in interstate or foreign commerce, and includes all transportation within this State for compensation in interstate or foreign commerce which has been exempted by Congress from federal regulation.

(16) "Intrastate operations" means the transportation of persons or household goods for compensation in intrastate commerce.

(16a) "Local exchange company" means a person holding, on January 1, 1995, a certificate to provide local exchange services or exchange access services.

(17) "Motor carrier" means a common carrier by motor vehicle.

(18) "Motor vehicle" means any vehicle, machine, tractor, semi-trailer, or any combination thereof, which is propelled or drawn by mechanical power and used upon the highways within the State.

(19) "Municipality" means any incorporated community, whether designated in its charter as a city, town, or village.

(20) Repealed by Session Laws 1995, c. 523, s. 1.

(21) "Person" means a corporation, individual, copartnership, company, association, or any combination of individuals or organizations doing business as a unit, and includes any trustee, receiver, assignee, lessee, or personal representative thereof.

(21a) "Plug-in electric vehicle" [means] a four-wheeled motor vehicle that meets each of the following requirements:

a. Is made by a manufacturer primarily for use on public streets, roads, and highways and meets National Highway Traffic Safety Administration standards included in 49 C.F.R. § 571.

b. Has not been modified from original manufacturer specifications with regard to power train or any manner of powering the vehicle.

c. Is rated at not more than 8,500 pounds unloaded gross vehicle weight.

d. Has a maximum speed capability of at least 65 miles per hour.

e. Draws electricity from a battery that has all of the following characteristics:

1. A capacity of not less than four kilowatt hours.

2. Capable of being recharged from an external source of electricity.

(22) "Private carrier" means any person, other than a carrier by rail, not included in the definitions of common carrier, which transports in intrastate commerce in its own vehicle or vehicles property of which such person is the owner, lessee, or bailee, when such transportation is for the purpose of sale, lease, rent, or bailment, or when such transportation is purely an incidental adjunct to some other established private business owned and operated by such person other than the transportation of household goods for compensation.

(23) a. "Public utility" means a person, whether organized under the laws of this State or under the laws of any other state or country, now or hereafter owning or operating in this State equipment or facilities for:

1. Producing, generating, transmitting, delivering or furnishing electricity, piped gas, steam or any other like agency for the production of light, heat or power to or for the public for compensation; provided, however, that the term "public utility" shall not include persons who construct or operate an electric generating facility, the primary purpose of which facility is either for (i) a person's own use and not for the primary purpose of producing electricity, heat, or steam for sale to or for the public for compensation or (ii) a person who constructs or operates an eligible solar energy facility on the site of a customer's property and leases such facility to that customer, as provided by and subject to the limitations of Article 6B of this Chapter;

2. Diverting, developing, pumping, impounding, distributing or furnishing water to or for the public for compensation, or operating a public sewerage system for compensation; provided, however, that the term "public utility" shall not include any person or company whose sole operation consists of selling water to less than 15 residential customers, except that any person or company which constructs a water system in a subdivision with plans for 15 or more lots and which holds itself out by contracts or other means at the time of said construction to serve an area containing more than 15 residential building lots shall be a public utility at the time of such planning or holding out to serve such 15 or more building lots, without regard to the number of actual

customers connected;

3. Transporting persons or household goods by street, suburban or interurban bus for the public for compensation;
4. Transporting persons or household goods by motor vehicles or any other form of transportation for the public for compensation, except motor carriers exempted in G.S. 62-260, carriers by rail, and carriers by air;
5. Transporting or conveying gas, crude oil or other fluid substance by pipeline for the public for compensation;
6. Conveying or transmitting messages or communications by telephone or telegraph, or any other means of transmission, where such service is offered to the public for compensation.

b. The term "public utility" shall for rate-making purposes include any person producing, generating or furnishing any of the foregoing services to another person for distribution to or for the public for compensation.

c. The term "public utility" shall include all persons affiliated through stock ownership with a public utility doing business in this State as parent corporation or subsidiary corporation as defined in G.S. 55-2 to such an extent that the Commission shall find that such affiliation has an effect on the rates or service of such public utility.

d. The term "public utility," except as otherwise expressly provided in this Chapter, shall not include a municipality, an authority organized under the North Carolina Water and Sewer Authorities Act, electric or telephone membership corporation; or any person not otherwise a public utility who furnishes such service or commodity only to himself, his employees or tenants when such service or commodity is not resold to or used by others; provided, however, that any person other than a nonprofit organization serving only its members, who distributes or provides utility service to his employees or tenants by individual meters or by other coin-operated devices with a charge for metered or coin-operated utility service shall be a public utility within the definition and meaning of this Chapter with respect to the regulation of rates and provisions of service rendered through such meter or coin-operated device imposing such separate metered utility charge. If any person conducting a public utility shall also conduct any enterprise not a public utility, such enterprise is not subject to the provisions of this Chapter. A water or sewer system owned by a homeowners' association that provides water or sewer service only to members or leaseholds of members is not subject to the provisions of this Chapter.

e. The term "public utility" shall include the University of North Carolina insofar as said University supplies telephone service, electricity or water to the public for compensation from the University Enterprises defined in G.S. 116-41.1(9).

f. The term "public utility" shall include the Town of Pineville insofar as said town supplies telephone services to the public for compensation. The territory to be served by the Town of Pineville in furnishing telephone services, subject to the Public Utilities Act, shall include the town limits as they exist on May 8, 1973, and shall also include the area proposed to be annexed under the town's ordinance adopted May 3, 1971, until January 1, 1975.

g. The term "public utility" shall not include a hotel, motel, time share or condominium complex operated primarily to serve transient occupants, which imposes charges to occupants for local, long-distance, or wide area telecommunication services when such calls are completed through the use of facilities provided by a public utility, and provided further that the local services received are rated in accordance with the provisions of G.S. 62-110(d) and the applicable charges for telephone calls are prominently displayed in each area where occupant rooms are located.

h. The term "public utility" shall not include the resale of electricity by (i) a campground operated primarily to serve transient occupants, or (ii) a marina; provided that (i) the campground or marina charges no more than the actual cost of the electricity supplied to it, (ii) the amount of electricity used by each campsite or marina slip occupant is measured by an individual metering device, (iii) the applicable rates are prominently displayed at or near each campsite or marina slip, and (iv) the campground or marina only resells electricity to campsite or marina slip occupants.

i. The term "public utility" shall not include the State, the Department of Information Technology, or the Microelectronics Center of North Carolina in the provision or sharing of switched broadband telecommunications services with non-State entities or organizations of the kind or type set forth in G.S. 143B-426.39.

j. The term "public utility" shall not include any person, not otherwise a public utility, conveying or transmitting messages or communications by mobile radio communications service. Mobile radio communications service includes one-way or two-way radio service provided to mobile or fixed stations or receivers using mobile radio service frequencies.

k. The term "public utility" shall not include a regional natural gas district organized and operated pursuant to Article 28 of Chapter 160A of the General Statutes.

l. The term "public utility" shall include a city or a joint agency under Part 1 of Article 20 of Chapter 160A of the General Statutes that provides service as defined in G.S. 62-3(23)a.6. and is subject to the provisions of G.S. 160A-340.1.

m. The term "public utility" shall not include a Ferry Transportation Authority created pursuant to Article 29 of Chapter 160A of the General Statutes.

n. The term "public utility" shall not include a person who uses an electric vehicle charging station to resell electricity to the public for compensation, provided that all of the following apply:

1. The reseller has procured the electricity from an electric power supplier, as defined in G.S. 62-133.8(a)(3), that is authorized to engage in the retail sale of electricity within the territory in which the electric vehicle charging service is provided.
2. All resales are exclusively for the charging of plug-in electric vehicles.
3. The charging station is immobile.
4. Utility service to an electric vehicle charging station shall be provided subject to the electric power supplier's terms and conditions.

Nothing in this sub-subdivision shall be construed to limit the ability of an electric power supplier to use electric vehicle charging stations to furnish electricity for charging electric vehicles. Any increases in customer demand or energy consumption associated with transportation electrification shall not constitute found revenues for an electric public utility.

(24) "Rate" means every compensation, charge, fare, tariff, schedule, toll, rental and classification, or any of them, demanded, observed, charged or collected by any public utility, for any service product or commodity offered by it to the public, and any rules, regulations, practices or contracts affecting any such compensation, charge, fare, tariff, schedule, toll, rental or classification.

(25) "Route" means the course or way which is traveled; the road or highway over which motor vehicles operate.

(26) "Securities" means stock, stock certificates, bonds, notes, debentures, or other evidences of ownership or of indebtedness, and any assumption or guaranty thereof.

(27) "Service" means any service furnished by a public utility, including any commodity furnished as a part of such service and any ancillary service or facility used in connection with such service.

(27a) "Small power producer" means a person or corporation owning or operating an electrical power production facility that qualifies as a "small power production facility" under 16 U.S.C. § 796, as amended.

(28) The word "State" means the State of North Carolina; "state" means any state.

(29) "Town" means any unincorporated community or collection of people having a geographical name by which it may be generally known and is so generally designated.

(30) "Panel" means a panel of three commissioners, a division of the Utilities Commission authorized for the purpose of carrying out certain functions of the Commission. (1913, c. 127, s. 7; C.S., s. 1112(b); 1933, c. 134, ss. 3, 8; c. 307, s. 1; 1937, c. 108, s. 2; 1941, cc. 59, 97; 1947, c. 1008, s. 3; 1949, c. 1132, s. 4; 1953, c. 1140, s. 1; 1957, c. 1152, s. 13; 1959, c. 639, ss. 12, 13; 1963, c. 1165, s. 1; 1967, c. 1094, ss. 1, 2; 1971, c. 553; c. 634, s. 1; cc. 894, 895; 1973, c. 372, s. 1; 1975, c. 243, s. 2; cc. 254, 415; 1979, c. 652, s. 1; 1979, 2nd Sess., c. 1219, s. 1; 1981 (Reg. Sess., 1982), c. 1186, s. 2; 1985, c. 676, s. 4; 1987, c. 445, s. 2; 1989, c. 110; 1993, c. 349, s. 1; 1993 (Reg. Sess., 1994), c. 777, s. 1(b); 1995, c. 27, ss. 2, 3; c. 509, s. 34; c. 523, s. 1; 1997-426, s. 8; 1997-437, s. 1; 1998-128, ss. 1-3; 2004-

199, s. 1; 2004-203, s. 37(a); 2005-95, s. 2; 2011-84, s. 2(a); 2015-241, s. 7A.4(e); 2017-120, s. 2; 2017-192, ss. 1(a), 6(b); 2019-132, s. 1(a), (b).)

§ 62-15. Office of executive director; public staff, structure and function.

(a) There is established in the Commission the office of executive director, whose salary and longevity pay shall be the same as that fixed for members of the Commission. "Service" for purposes of longevity pay means service as executive director of the public staff. The executive director shall be appointed by the Governor subject to confirmation by the General Assembly by joint resolution. The name of the executive director appointed by the Governor shall be submitted to the General Assembly on or before May 1 of the year in which the term of his office begins. The term of office for the executive director shall be six years, and the initial term shall begin July 1, 1977. The executive director may be removed from office by the Governor in the event of his incapacity to serve; and the executive director shall be removed from office by the Governor upon the affirmative recommendation of a majority of the Commission, after consultation with the Joint Legislative Oversight Committee on Agriculture and Natural and Economic Resources, the Senate Appropriations Committee on Agriculture, Natural, and Economic Resources, and the chairs of the House of Representatives Appropriations Committee on Agriculture and Natural and Economic Resources of the General Assembly. In case of a vacancy in the office of executive director for any reason prior to the expiration of his term of office, the name of his successor shall be submitted by the Governor to the General Assembly, not later than four weeks after the vacancy arises. If a vacancy arises in the office when the General Assembly is not in session, the executive director shall be appointed by the Governor to serve on an interim basis pending confirmation by the General Assembly.

(b) There is established in the Commission a public staff. The public staff shall consist of the executive director and such other professional, administrative, technical, and clerical personnel as may be necessary in order for the public staff to represent the using and consuming public, as hereinafter provided. All such personnel shall be appointed, supervised, and directed by the executive director. The public staff shall not be subject to the supervision, direction, or control of the Commission, the chairman, or members of the Commission.

(c) Except for the executive director, the salaries and compensation of all such personnel shall be fixed in the manner provided by law for fixing and regulating salaries and compensation by other State agencies.

(d) It shall be the duty and responsibility of the public staff to:

(1) Review, investigate, and make appropriate recommendations to the Commission with respect to the reasonableness of rates charged or proposed to be charged by any public utility and with respect to the consistency of such rates with the public policy of assuring an energy supply adequate to protect the public health and safety and to promote the general welfare;

(2) Review, investigate, and make appropriate recommendations to the Commission with respect to the service furnished, or proposed to be furnished by any public utility;

(3) Intervene on behalf of the using and consuming public, in all Commission proceedings affecting the rates or service of any public utility;

(4) When deemed necessary by the executive director in the interest of the using and consuming public, petition the Commission to initiate proceedings to review, investigate, and take appropriate action with respect to the rates or service of public utilities;

(5) Intervene on behalf of the using and consuming public in all certificate applications filed pursuant to the provisions of G.S. 62-110.1, and provide assistance to the Commission in making the analysis and plans required pursuant to the provisions of G.S. 62-110.1 and 62-155;

(6) Intervene on behalf of the using and consuming public in all proceedings wherein any public utility proposes to reduce or abandon service to the public;

(7) Investigate complaints affecting the using and consuming public generally which are directed to the Commission, members of the Commission, or the public staff and where appropriate make recommendations to the Commission with respect to such complaints;

(8) Make studies and recommendations to the Commission with respect to standards, regulations, practices, or service of any public utility pursuant to the provisions of G.S. 62-43; provided, however, that the public staff shall have no duty, responsibility, or authority with respect to the enforcement of natural gas pipeline safety laws, rules, or regulations;

(9) When deemed necessary by the executive director, in the interest of the using and consuming public, intervene in Commission proceedings with respect to transfers of franchises, mergers, consolidations, and combinations of public utilities pursuant to the provisions of G.S. 62-111;

(10) Investigate and make appropriate recommendations to the Commission with respect to applications for certificates by radio common carriers, pursuant to the provisions of Article 6A of this Chapter;

(11) Review, investigate, and make appropriate recommendations to the Commission with respect to

contracts of public utilities with affiliates or subsidiaries, pursuant to the provisions of G.S. 62-153;

(12) When deemed necessary by the executive director, in the interest of the using and consuming public, advise the Commission with respect to securities, regulations, and transactions, pursuant to the provisions of Article 8 of this Chapter.

(e) The public staff shall have no duty, responsibility, or authority with respect to the laws, rules or regulations pertaining to the physical facilities or equipment of common, contract and exempt carriers, the registration of vehicles or of insurance coverage of vehicles of common, contract and exempt carriers; the licensing, training, or qualifications of drivers or other persons employed by common, contract and exempt carriers, or the operation of motor vehicle equipment by common, contract and exempt carriers in the State.

(f) The executive director representing the public staff shall have the same rights of appeal from Commission orders or decisions as other parties to Commission proceedings.

(g) Upon request, the executive director shall employ the resources of the public staff to furnish to the Commission, its members, or the Attorney General, such information and reports or conduct such investigations and provide such other assistance as may reasonably be required in order to supervise and control the public utilities of the State as may be necessary to carry out the laws providing for their regulation.

(h) The executive director is authorized to employ, subject to approval by the State Budget Officer, expert witnesses and such other professional expertise as the executive director may deem necessary from time to time to assist the public staff in its participation in Commission proceedings, and the compensation and expenses therefor shall be paid by the utility or utilities participating in said proceedings. Such compensation and expenses shall be treated by the Commission, for rate-making purposes, in a manner generally consistent with its treatment of similar expenditures incurred by utilities in the presentation of their cases before the Commission. An accounting of such compensation and expenses shall be reported annually to the Joint Legislative Oversight Committee on Agriculture and Natural and Economic Resources, the Senate Appropriations Committee on Agriculture, Natural, and Economic Resources, and the chairs of the House of Representatives Appropriations Committee on Agriculture and Natural and Economic Resources and to the Speaker of the House of Representatives and the President Pro Tempore of the Senate.

(i) The executive director, within established budgetary limits, and as allowed by law, shall authorize and approve travel, subsistence, and related necessary expenses of the executive director or members of the public staff, incurred while traveling on official business. (1949, c. 1009, s. 3; 1963, c. 1165, s. 1; 1977, c. 468, s. 4; 1981, c. 475; 1983, c. 717, s. 12.1; 1985, c. 499, s. 4; 1989, c. 781, s. 41.3; 1989 (Reg. Sess., 1990), c. 1024, s. 13; 1999-237, s. 28.21A; 2011-291, ss. 2.8, 2.9; 2017-57, s. 14.1(p).)

§ 62-20. Participation by Attorney General in Commission proceedings.

The Attorney General may intervene, when he deems it to be advisable in the public interest, in proceedings before the Commission on behalf of the using and consuming public, including utility users generally and agencies of the State. The Attorney General may institute and originate proceedings before the Commission in the name of the State, its agencies or citizens, in matters within the jurisdiction of the Commission. The Attorney General may appear before such State and federal courts and agencies as he deems it advisable in matters affecting public utility services. In the performance of his responsibilities under this section, the Attorney General shall have the right to employ expert witnesses, and the compensation and expenses therefor shall be paid from the Contingency and Emergency Fund. The Commission shall furnish the Attorney General with copies of all applications, petitions, pleadings, order and decisions filed with or entered by the Commission. The Attorney General shall have access to all books, papers, studies, reports and other documents filed with the Commission. (1949, c. 989, s. 1; c. 1029, s. 3; 1959, c. 400; 1963, c. 1165, s. 1; 1977, c. 468, s. 8.)

§ 62-32. Supervisory powers; rates and service.

(a) Under the rules herein prescribed and subject to the limitations hereinafter set forth, the Commission shall have general supervision over the rates charged and service rendered by all public utilities in this State.

(b) Except as provided in this Chapter for bus companies, the Commission is hereby vested with all powers necessary to require and compel any public utility to provide and furnish to the citizens of this State reasonable service of the kind it undertakes to furnish and fix and regulate the reasonable rates and charges to be made for such service. (1913, c. 127, s. 7; C.S., s. 1112(b); 1933, c. 134, s. 3; 1937, c. 108, s. 2; 1941, cc. 59, 97; 1959, c. 639, s. 12; 1963, c. 1165, s. 1; 1985, c. 676, s. 5.)

Article 7.

Rates of Public Utilities.

§ 62-130. Commission to make rates for public utilities.

(a) The Commission shall make, fix, establish or allow just and reasonable rates for all public utilities subject to its jurisdiction. A rate is made, fixed, established or allowed when it becomes effective pursuant to the provisions of this Chapter.

(b) Repealed by Session Laws 1985, c. 676, s. 15.

(c) The Commission may make, require or approve, after public hearing, for intrastate shipments what are known as milling-in-transit, processing-in-transit, or warehousing-in-transit rates on grain, lumber to be dressed, cotton, peanuts, tobacco, or such other commodities as the Commission may designate.

(d) The Commission shall from time to time as often as circumstances may require, change and revise or cause to be changed or revised any rates fixed by the Commission, or allowed to be charged by any public utility.

(e) In all cases where the Commission requires or orders a public utility to refund moneys to its customers which were advanced by or overcollected from its customers, the Commission shall require or order the utility to add to said refund an amount of interest at such rate as the Commission may determine to be just and reasonable; provided, however, that such rate of interest applicable to said refund shall not exceed ten percent (10%) per annum. (1899, c. 164, ss. 2, 7, 14; 1903, c. 683; Rev., ss. 1096, 1099, 1106; 1907, c. 469, s. 4; Ex. Sess. 1908, c. 144, s. 1; 1913, c. 127, s. 2; 1917, c. 194; C.S., ss. 1066, 1071, 3489; Ex. Sess. 1920, c. 51, s. 1; 1925, c. 37; 1929, cc. 82, 91; 1933, c. 134, s. 8; 1941, c. 97; 1953, c. 170; 1963, c. 1165, s. 1; 1981, c. 461, s. 1; 1985, c. 676, s. 15(1).)

§ 114-2. Duties.

Pursuant to Section 7(2) of Article III of the North Carolina Constitution, it shall be the duty of the Attorney General:

(1) To defend all actions in the appellate division in which the State shall be interested, or a party, and to appear for the State in any other court or tribunal in any cause or matter, civil or criminal, in which the State may be a party or interested. The duty to represent the State in criminal appeals shall not be delegated to any district attorney's office or any other entity.

(2) To represent all State departments, agencies, institutions, commissions, bureaus or other organized activities of the State which receive support in whole or in part from the State. Where the Attorney General represents a State department, agency, institution, commission, bureau, or other organized activity of the State which receives support in whole or in part from the State, the Attorney General shall act in conformance with Rule 1.2 of the Rules of Professional Conduct of the North Carolina State Bar.

(3) Repealed by Session Laws 1973, c. 702, s. 2.

(4) To consult with and advise the prosecutors, when requested by them, in all matters pertaining to the duties of their office.

(5) To give, when required, his opinion upon all questions of law submitted to him by the General Assembly, or by either branch thereof, or by the Governor, Auditor, Treasurer, or any other State officer.

(6) To pay all moneys received for debts due or penalties to the State immediately after the receipt thereof into the treasury.

(7) To compare the warrants drawn on the State treasury with the laws under which they purport to be drawn.

(8) Subject to the provisions of G.S. 62-20:

a. To intervene, when he deems it to be advisable in the public interest, in proceedings before any courts, regulatory officers, agencies and bodies, both State and federal, in a representative capacity for and on behalf of the using and consuming public of this State. He shall also have the authority to institute and originate proceedings before such courts, officers, agencies or bodies and shall have authority to appear before agencies on behalf of the State and its agencies and citizens in all matters affecting the public interest.

b. Upon the institution of any proceeding before any State agency by application, petition or other pleading, formal or informal, the outcome of which will affect a substantial number of residents of North Carolina, such agency or agencies shall furnish the Attorney General with copies of all such applications, petitions and pleadings so filed, and, when the Attorney General deems it advisable in the public interest to intervene in such proceedings, he is authorized to file responsive pleadings and to appear before such agency either in a representative capacity in behalf of the using and consuming public of this State or in behalf of the State or any of its agencies.

(9) To notify the Speaker of the House of Representatives and the President Pro Tempore of the Senate whenever an action is filed in State or federal court that challenges the validity of a North Carolina statute or provision of the North Carolina Constitution under State or federal law.

(10) Pursuant to G.S. 120-32.6, to represent upon request and otherwise abide by and defer to the final decision-making authority exercised by the Speaker of the House of Representatives and the President Pro Tempore of the Senate, as agents of the State through the General Assembly, in defending any State or federal action challenging the validity or constitutionality of an act of the General Assembly or a provision of the North Carolina Constitution. If for any reason the Attorney General cannot perform the duty specified herein, the Attorney General may recuse personally from such defense but shall appoint another attorney employed by the Department of Justice to act at the direction of the Speaker of the House of Representatives and the President Pro Tempore of the Senate. (1868-9, c. 270, s. 82; 1871-2, c. 112, s. 2; Code, s. 3363; 1893, c. 379; 1901, c. 744; Rev., s. 5380; C.S., s. 7694; 1931, c. 243, s. 5; 1933, c. 134, s. 8; 1941, c. 97; 1967, c. 691, s. 51; 1969, c. 535; 1973, c. 702, s. 2; 1977, c. 468, s. 17; 1979, c. 107, s. 9; 1983, c. 913, s. 15; 2014-100, s. 17.3A(b); 2017-57, s. 6.7(m); 2017-212, s. 5.2(a).)

CONTENTS OF ADDENDUM

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-7, SUB 1213
DOCKET NO. E-7, SUB 1214
DOCKET NO. E-7, SUB 1187

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1213 In the Matter of Petition of Duke Energy Carolinas, LLC, for Approval of Prepaid Advantage Program DOCKET NO. E-7, SUB 1214 In the Matter of Application by Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina DOCKET NO. E-7, SUB 1187 In the Matter of Application of Duke Energy Carolinas, LLC for an Accounting Order to Defer Incremental Storm Damage Expenses Incurred as a Result of Hurricanes Florence and Michael and Winter Storm Diego	ORDER ACCEPTING STIPULATIONS, GRANTING PARTIAL RATE INCREASE, AND REQUIRING CUSTOMER NOTICE

HEARD: Wednesday, January 15, 2020, at 7:00 p.m., in Courtroom A, Macon County Courthouse, 5 West Main Street, Franklin, North Carolina

Thursday, January 16, 2020, at 7:00 p.m., in the Burke County Courthouse, 201 South Green Street, Morganton, North Carolina

Wednesday, January 29, 2020, at 7:00 p.m., in the Alamance County Historic Courthouse, 1 SE Court Square, Graham, North Carolina

Thursday, January 30, 2020, at 7:00 p.m., in Courtroom 5350, Mecklenburg County Courthouse, 832 East 4th Street, Charlotte, North Carolina

Monday, August 24, 2020, at 2:00 p.m., held via video conference, and reconvened on Thursday, September 3, 2020, at 9:00 a.m., via video conference

BEFORE: Chair Charlotte A. Mitchell, Presiding; and Commissioners ToNola D. Brown-Bland, Lyons Gray, Daniel G. Clodfelter, Kimberly W. Duffley, Jeffrey A. Hughes, and Floyd B. McKissick, Jr.

APPEARANCES

For Duke Energy Carolinas, LLC:

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For Carolina Utility Customers Association, Inc.:[1]

Robert F. Page, Crisp & Page, PLLC, 4010 Barrett Drive, Suite 205, Raleigh, North Carolina 27609

[1] On January 12, 2021, the Commission granted the motion of Mr. Page, Marcus Trathen, and Craig Schauer to allow Mr. Page to withdraw as CUCA's counsel and to substitute Mr. Trathen and Mr. Schauer as counsel for CUCA.

For North Carolina Sustainable Energy Association:

Peter H. Ledford, General Counsel, and Benjamin Smith, Regulatory Counsel, North Carolina Sustainable Energy Association, 4800 Six Forks Road, Suite 300, Raleigh, North Carolina 27609

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For Apple Inc., Facebook, Inc., and Google LLC:

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For North Carolina Justice Center, North Carolina Housing Coalition, Natural Resources Defense Council, and Southern Alliance for Clean Energy:

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North Carolina Clean Energy Business Alliance:

Karen Kemerait, Fox Rothschild LLP, 434 Fayetteville Street, Suite 2800, Raleigh, North Carolina 27601

For North Carolina League of Municipalities:

Deborah Ross, Fox Rothschild LLP, 434 Fayetteville Street, Suite 2800, Raleigh, North Carolina 27601

For Center for Biological Diversity and Appalachian Voices:

Howard M. Crystal, Senior Attorney, and Jean Su, Staff Attorney and Energy Director–Biological Diversity, 1411 K Street NW, Suite 1300, Washington, DC 20005

For the Using and Consuming Public:

Dianna W. Downey, Chief Counsel; and Elizabeth D. Culpepper, Layla Cummings, Tim R. Dodge, Lucy E. Edmondson, William E. Grantmyre, Gina C. Holt, Megan Jost, John D. Little, and Nadia L. Luhr, Staff Attorneys, Public Staff–North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

Teresa Townsend, Special Deputy Attorney General, and Margaret A. Force, Assistant Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27603

INDEX TO SUBSTANTIVE ISSUES

BY THE COMMISSION: On August 29, 2019, pursuant to Commission Rule R1-17(a), Duke Energy Carolinas, LLC (DEC or Company), filed notice of its intent to file a general rate case application.

On September 30, 2019, DEC filed an Application to Adjust Retail Rates and Request for an Accounting Order (Application), along with the required Rate Case Information Report, Form E-1 (Form E-1), and the direct testimony and exhibits of numerous witnesses.

PROCEDURAL HISTORY AND JURISDICTION

Procedural History

The Commission has issued a multitude of procedural orders in these dockets, all of which are a matter of record herein. The following is a summary of the most pertinent filings by the parties and the Commission's procedural orders.

On various dates petitions to intervene were filed by the following parties and were granted by orders of the Commission: Carolina Industrial Group for Fair Utility Rates III (CIGFUR); Carolina Utility Customers Association, Inc. (CUCA); North Carolina Sustainable Energy Association (NCSEA); Vote Solar; Sierra Club; Center for Biological Diversity and Appalachian Voices (CBD/AV); North Carolina Waste Awareness and Reduction Network (NC WARN); Commercial Group; Apple Inc., Facebook, Inc., and Google LLC (collectively, the Tech Customers); North Carolina Justice Center (NCJC), North Carolina Housing Coalition (NCHC), Natural Resources Defense Council (NRDC), and Southern Alliance for Clean Energy (SACE; together with NCJC, NCHC, and NRDC, NCJC et al.); Harris Teeter LLC; North Carolina Clean Energy Business Alliance (NCCEBA); and North Carolina League of Municipalities (NCLM). In addition, a Notice of Intervention was filed by the North Carolina Attorney General's Office (AGO). The Public Staff's intervention is recognized pursuant to N.C. Gen. Stat. § 62-15(d) and Commission Rule R1-19(e).

On October 29, 2019, the Commission issued an Order Establishing General Rate Case, Suspending Rates, Scheduling Hearings, and Requiring Public Notice (Scheduling Order).

On November 20, 2019, the Commission issued an order consolidating DEC's petition for approval of its Prepaid Advantage Program in Docket No. E-7, Sub 1213 with DEC's rate case.

In January 2020, the Commission held four public hearings as scheduled by the Commission's October 29, 2019 Order for the purpose of receiving the testimony of public witnesses.

On February 18, 2020, the Public Staff and numerous other parties filed the direct testimony and exhibits of their witnesses.

On March 4, 2020, DEC filed the rebuttal testimony and exhibits of several witnesses.

The expert witness hearing in this matter was initially set to commence on March 23, 2020. However, due to the novel coronavirus (COVID-19) pandemic and the declared State of Emergency issued by Governor Roy Cooper, on March 16, 2020, the Commission issued an order postponing the expert witness hearing until further order of the Commission and accepting DEC's prospective waiver of its right to implement its original proposed rates by operation of N.C.G.S. § 62-134(b).

On March 25, 2020, DEC and the Public Staff filed their Agreement and Stipulation of Partial Settlement (First Partial Stipulation).

On May 6, 2020, DEC, Duke Energy Progress, LLC (DEP), and the Public Staff filed a motion to consolidate for hearing DEC's Application and DEP's application for a rate increase filed in Docket No. E-2, Sub 1219 (DEP Application). Their motion stated that many of the issues in the two general rate case proceedings were based on substantially similar testimony and that efficiencies could be gained by consolidating the expert witness hearings for DEC and DEP (collectively, the Companies), particularly in light of logistical challenges related to the COVID-19 State of Emergency.

On June 17, 2020, the Commission issued an order revising the schedule for the DEC expert witness hearing and consolidating the DEC hearing with the expert witness hearing in the DEP Application on several topics, with the hearing to be held remotely by video conference.

On June 22, 2020, DEC filed a Petition for an Accounting Order to Defer Impacts of Its Suspended Rate Case in Lieu of Implementing Temporary Rates Under Bond requesting to defer the revenue impacts of the postponement of the expert witness hearing.

On June 26, 2020, the Commission entered an order consolidating DEC's rate case and Prepaid Advantage Program dockets with the Company's application in Docket No. E-7, Sub 1187 for an accounting order to defer incremental storm damage expenses incurred as a result of Hurricanes Florence and Michael and Winter Storm Diego.

On July 9, 2020, the Commission issued an order denying DEC's Petition for an Accounting Order.

On July 24, 2020, DEC filed a Motion for Approval of Notice Required by N.C. Gen. Stat. § 62-135 to Implement Temporary Rates, Subject to Refund, and Authorization of EDIT Rider together with a Motion for Approval of Undertaking Required by N.C.G.S. § 62-135(c) to Implement Temporary Rates, Subject to Refund. The Commission issued an order on August 6, 2020, approving DEC's financial undertaking and proposed public notice of temporary rates.

On July 31, 2020, DEC and the Public Staff filed their Second Agreement and Stipulation of Partial Settlement (Second Partial Stipulation).

On August 10, 2020, the Commission issued an order scheduling a separate expert witness hearing on DEC's Application to address issues that would not be addressed in the DEC/DEP consolidated hearing.

On August 24, 2020, the matter came on for the consolidated expert witness hearing. Testimony and exhibits were presented for DEC, DEP, and several parties on financial issues, including cost of capital, capital structure, and credit quality, as well as Excess Deferred Income Taxes (EDIT), Grid Improvement Plan (GIP), and rate affordability. The DEC-specific (nonconsolidated) expert witness hearing commenced on September 3, 2020, and DEC and the parties presented testimony and exhibits on numerous additional issues.

In accordance with orders of the Commission, several parties submitted post-hearing briefs and proposed orders on November 4, 2020.

On January 25, 2021, the Companies, the Public Staff, the AGO, and Sierra Club (collectively, CCR Settling Parties) filed the Coal Combustion Residuals (CCR) Settlement Agreement (CCR Settlement) in these dockets and in the dockets in which the DEP Application is pending.

On January 29, 2021, DEC filed the testimony and exhibits of several witnesses supporting the CCR Settlement; DEC filed correction to certain of that testimony on February 1, 2021. Also on January 29, 2021, the CCR Settling Parties filed a Joint Motion to Reopen Record, Consolidate Consideration of CCR Settlement Agreement, and for Approval of CCR Settlement Agreement.

On February 5, 2021, the Public Staff filed the testimony and exhibits of several witnesses supporting the CCR Settlement.

On February 12, 2021, the Commission issued an Order Reopening Records, Allowing Testimony or Comments on Proposed Settlement, and Allowing Requests for Hearing. No such testimony or comments were filed by any party, and no party requested a hearing.

Lastly, on February 17, 2021, the Commission issued an Order Requiring Responses to Commission Questions specifically related to the CCR Settlement, responses to which were filed by the Companies on February 23, 2021.

Jurisdiction

No party has contested the fact that DEC is a public utility subject to the Commission's jurisdiction pursuant to the Public Utilities Act, Chapter 62 of the North Carolina General Statutes. The Commission concludes that it has personal jurisdiction over DEC and subject matter jurisdiction over the matters presented in DEC's Application.

Application

In summary, DEC requested in its September 30, 2019 Application an annual North Carolina retail base rate increase of approximately $445.3 million, an approximately 9.2% increase over its current North Carolina retail base rates. DEC also proposed to return to ratepayers approximately $154.6 million annually of EDIT.

In its Application, DEC stated that its need for a rate increase is driven primarily by costs of improving the reliability and safety of its operations, costs of restoring service after Hurricanes Florence and Michael and Winter Storm Diego, costs of coal ash remediation, an increase in depreciation expense due to accelerated retirement dates for coal-fired generation units, and upgrades to generating plants and transmission assets. DEC witnesses testified that the appropriate test period in this case is the 12 months ended December 31, 2018, with updates to costs, revenues, and rate base through May 31, 2020. As a result of the updates to DEC's costs, revenues, and rate base, on July 2, 2020, DEC revised its requested rate increase to approximately $414.5 million.

Pursuant to the authority granted to public utilities under N.C.G.S. § 62-135 to implement temporary rates, subject to refund, on August 24, 2020, DEC implemented temporary rates pending a final order in this proceeding.

Whole Record

The Commission held four public witness hearings, as noted above. The following public witnesses appeared and testified:

Franklin: Victoria Estes, Elsa Enstrom, Patricia Bailey, Al Bernard, William Thomas, Callie Moore, Tamara Zwinak, Pat McGee, Katie Breckheimer, and Debra Uccetta

Morganton: Rory McIlmoil, Henry Belada, Phil Bisesi, Chris Kanipe, Matt Wasson, and Jeff Deal

Graham: Beth McKee-Huger, Carolina Armijo, Deborah Graham, Harry Phillips, Leonard Williams, John Merrell, Bobby Jones, Ron Namest, Heather Sanchez, Rachel Velez, Linda Nelson, Anne Cassebaum, Timothy Greene, Carole Troxler, Peggy Wilson, Herald Voss, Jillian Riley, John Loftis, Harry Clapp, Abigail Rosenthal, John Wagner, John Martin, Deborah Smith, Joseph Alston, and Wendy Wilson

Charlotte: Steve Allinger, Nicholas Rose, Steve Copulsky, Kenneth Kneidel, Dave Walsh, Sally Kneidel, Beth Henry, Kent Moore, Kent Crawford, Holli Adams, Tina Katsanos, Dennis Testerman, Maya Wells, Andrew Goff, Jim Backman, Allen Smit h, Shawn Richardson, Louri Fox, Lucas Blanco, Nancy Carter, Jerome Wagner, Nancy Duncan, Cate De Mallie, John Hudspeth, Bethany Menut, Katherine Sparrow, Ricardo Arevalo, Doug Swaim, Kate Lewin, and Corbin Steele

In summary, almost all the public witnesses stated their opposition to DEC's proposed rate increase. *See generally*, tr. vols. 1-4. Many witnesses testified that they were on fixed incomes and about the poverty in some of the counties served by DEC. They specifically mentioned high medical bills, student debt, lost pensions, and displaced workers as causes of poverty and difficulty in paying electric bills. In addition, many public witnesses stated concerns about coal ash, including the health effects on people located in proximity to coal ash basins and contamination of water supplies. Further, witnesses expressed their view that it is unfair for the cost of the coal ash cleanup to burden ratepayers rather than coming out of the Company's or shareholders' profits. They also spoke of the insurance companies not paying for the coal ash cleanup costs. Moreover, public witnesses testified to their concerns regarding DEC's use of fossil fuels, including coal and natural gas power plants, fracking, and DEC's not adequately increasing the use of clean energy and renewables. Some witnesses connected these concerns with the increased effects of hurricanes, storm recovery, and the proposed Atlantic Coast Pipeline. Finally, some public witnesses voiced their view that DEC's executive compensation and shareholder dividends are excessive.

In addition to the public witness testimony, the Commission received numerous written consumer statements of position, all of which were filed in the docket. *See generally*, Docket No. E-7, Sub 1214CS. The public witness testimony and consumer statements of position have been considered by the Commission in its deliberations on DEC's rate case Application.

In the Scheduling Order the Commission took judicial notice pursuant to N.C.G.S. § 62-65 of all evidence, decisions, and matters of record on the issues of coal ash remediation, Power Forward, and Advanced Metering Infrastructure (AMI) in DEC's last general rate case, Docket No. E-7, Sub 1146 (Sub 1146). Said evidence, decisions, and matters of record were accepted into evidence in the present docket and are hereby incorporated by reference into this Order. The judicially noticed evidence will not be repeated in full or summarized, but portions of the testimony and exhibits are referenced throughout this Order.[2]

The testimony and exhibits in this proceeding are voluminous. The Commission has carefully considered all of the evidence and the record as a whole. However, the Commission has not attempted to recount every statement of every witness in this Order. Rather, the Commission has summarized the evidence that is in the record. Likewise, while the Commission has read and fully considered the parties' post-hearing briefs, it has not in this Order attempted expressly to summarize or discuss every contention advanced or authority cited in the briefs.

[2] The form of the transcript reference in this Order for the Sub 1146 evidence is, for example, "2018 Tr. vol. 8, 209." The form of the exhibits reference for the Sub 1146 exhibits is, for example, "2018 Public Staff Maness Direct Ex. 4." Additionally, the form of the transcript reference in this Order for the consolidated hearing held August 24, 2020, through August 31, 2020, is, for example, "Consolidated Tr. vol. 3, 194," and the exhibits reference is, for example, "Consolidated DEC Pirro Rebuttal Ex. 2."

Based upon the foregoing and the entire record in this proceeding the Commission makes the following

FINDINGS OF FACT

Stipulations

1. On March 25, 2020, DEC and the Public Staff filed the First Partial Stipulation resolving some of the issues between the two parties, and on July 31, 2020, the Public Staff and DEC filed the Second Partial Stipulation resolving several additional issues.

2. On various dates during this proceeding, DEC entered into and filed stipulations and amendments thereto with Harris Teeter (HT Stipulation), Commercial Group (CG Stipulation), CIGFUR (CIGFUR Stipulation), and Vote Solar (Vote Solar Stipulation), and entered into and filed a joint stipulation with NCSEA and NCJC et al. (NCSEA/NCJC et al. Stipulation), each of which resolved some of the issues in this proceeding between DEC and these parties.

3. The stipulations with the Public Staff, Harris Teeter, Commercial Group, CIGFUR, Vote Solar, NCSEA, and NCJC et al. are products of the give-and-take settlement negotiations between DEC the respective parties.

Base Fuel and Fuel-Related Cost Factors

4. Consistent with Section IV.N of the Second Partial Stipulation, the total base fuel and fuel-related cost factors, by customer class, represented by the sum of the respective base fuel and fuel-related costs factors set in Sub 1146 and the annual non-EMF fuel and fuel-related costs riders approved in Docket No. E-7, Sub 1228 (Sub 1228) are just and reasonable to all parties.

Amortization of Loss on Hydro Station Sale

5. Amortization of the Company's loss on the sale of hydro stations over the overall remaining depreciable life of the assets of 20 years reasonably spreads the loss on sale over the years in which customers would have otherwise received service from the hydro stations.

6. It is just and reasonable to adopt the 20-year amortization period for the Company's loss on the sale of hydro stations recommended by the Public Staff as opposed to the seven-year period recommended by the Company.

7. It is appropriate for DEC to earn a return on the unamortized balance related to the loss on the sale of hydro stations.

Depreciation Study

8. Use of a 10% contingency for future “unknowns” in the estimate of future terminal net salvage costs is reasonable.

9. Use of an interim net salvage percentage of zero for Accounts 342, 343, 344, 345, and 346 is reasonable.

10. Use of escalation of terminal net salvage cost and the straight-line method of depreciation in determining escalation as performed in the Decommissioning Study is reasonable.

11. Use of the Company’s proposed future net salvage for mass property Account 366, Underground Conduit, is reasonable.

12. Use of an average service life of 15 years for the new AMI meters is reasonable.

13. Except where specifically addressed in this Order, the depreciation rates proposed by DEC, which are based on the Depreciation Study filed by the Company as Spanos Direct Exhibit 1 and the Decommissioning Cost Estimate Study filed by the Company as Doss Direct Exhibit 4 in Sub 1146, are just and reasonable.

Early Retirement of Coal Plants

14. The integrated resource planning (IRP) proceeding is the appropriate proceeding for a thorough review of generating plant retirements.

15. The depreciation rates for the Allen Units 4 and 5 and Cliffside Unit 5 generating plants should be based upon the remaining lives of the plants.

Alleged Uneconomical Coal Plant Costs

16. DEC’s investments in its coal fleet were reasonably and prudently incurred to enable DEC to meet its obligation to provide safe, adequate, and reliable electric service.

17. It is not necessary or appropriate to impose a limit on DEC’s future investments in its coal-fired generating assets.

18. DEC’s costs associated with the Belews Creek Unit 1 dual fuel optionality (DFO) project resulted in used and useful property and should be recovered.

CCR Cost Recovery

19. North Carolina enacted the Coal Ash Management Act (CAMA) in 2014, which was amended in 2016, and the United States Environmental Protection Agency

(EPA) promulgated its final rule, the Coal Combustion Residuals Rule (CCR Rule), in 2015. Together, these state and federal laws and regulations introduced new requirements for the management of coal ash and mandated the closure of the coal ash basins at all of the Company's coal-fired power plants.

20. Since its last rate case, DEC has incurred significant additional costs to continue the closure and compliance efforts related to these federal and state legal requirements and its management and storage of CCR. On a North Carolina retail jurisdictional basis, as of July 31, 2020, the CCR costs DEC incurred for which it seeks recovery in this rate case amount to $378,464,403, $341,658,176 of which are the actual deferred coal ash basin closure and compliance costs incurred by the Company during the period from January 1, 2018, through January 31, 2020, and the remaining $36,806,227 of which are the financing costs incurred by the Company upon the deferred costs through July 2020.

21. The January 25, 2021 CCR Settlement, which is the product of give-and-take settlement negotiations in resolving the issues among the CCR Settling Parties related to CCR cost recovery, is material evidence in this proceeding and is entitled to be given appropriate weight in this proceeding along with other evidence adduced by the Company and intervenor parties.

22. Section III.E of the CCR Settlement provides that the amount of CCR costs and financing costs sought for recovery in this case will be reduced by $224 million. Additionally, Section III.E provides for the recovery of financing costs sought for recovery in this case during the deferral period, calculated at the weighted average cost of capital, as well as during a five-year amortization period, calculated using: (1) DEC's cost of debt as previously stipulated by the Company and the Public Staff in the Second Partial Stipulation adjusted as appropriate to reflect the deductibility of interest expense; (2) a cost of equity 150 basis points below the 9.60% stipulated to in the Second Partial Stipulation; and (3) a 48% debt and 52% equity capital structure.

23. Section III.F of the CCR Settlement provides that the amount to be recovered of CCR costs incurred by DEC from February 1, 2020, through January 31, 2030, along with associated financing costs incurred during the deferral period, will be reduced by $108 million but allows for recovery of any remaining CCR costs, subject to determination by the Commission that such costs were reasonably and prudently incurred. Additionally, Section III.F provides for recovery of financing costs during the applicable deferral period, calculated at the weighted average cost of capital, and provides for recovery of financing costs during the applicable amortization period, calculated using a reduced cost of equity.

24. Section III.D.i of the CCR Settlement provides that the CCR Settling Parties waive their right to assert that future CCR costs should be shared between the Company and ratepayers through equitable sharing of the costs or other adjustment except as provided in the CCR Settlement. Section III.D.ii provides that the CCR Settling Parties waive their right to challenge future CCR costs on the basis that the Company's historical coal ash management practices were inadequate and led to unreasonable CCR costs

being incurred or led to CCR costs being unreasonably higher than otherwise would have been incurred. Section III.D.iii of the CCR Settlement provides that the CCR Settling Parties reserve their right to propose an adjustment to future CCR costs on the grounds that the costs were otherwise unreasonable or were imprudently incurred.

25. Section III.G of the CCR Settlement provides for an allocation between the Companies and their customers of any proceeds from ongoing coal ash insurance litigation.

26. The provisions of the CCR Settlement are just and reasonable in light of all of the evidence presented. It is appropriate for the Company to reduce the balance of deferred CCR costs sought to be recovered in this rate case by $224 million. It is appropriate that the $224 million reduction reduce the deferred CCR costs as of December 31, 2020, and that DEC cease to accrue financing costs on that amount after December 31, 2020, and not seek to recover such financing costs from customers, as set forth in Section E of the CCR Settlement. After such reduction and updating financing costs through June 2021, the net amount for which the Company seeks recovery in this case is $169,528,066. It is further appropriate for the Company to defer CCR costs incurred since February 1, 2020, and to reduce the balance of deferred CCR costs sought to be recovered in its next general rate case by $108 million as set forth in Section III.F of the CCR Settlement. It is appropriate that no financing costs accrue on the $108 million as of December 31, 2020, as set forth in Section III.F of the CCR Settlement. The reduced financing costs agreed upon in Sections III.E and III.F of the CCR Settlement are appropriate.

ARO Accounting

27. DEC is required to comply with Generally Accepted Accounting Principles (GAAP), specifically, Accounting Standards Codification 410, Asset Retirement and Environmental Obligations (ASC 410), and ASC 980, Regulated Operations.

28. DEC is required to comply with the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts (USOA), specifically, General Instruction No. 25, Accounting for Asset Retirement Obligations.

29. Neither GAAP nor FERC accounting drives cost recovery for North Carolina retail ratemaking purposes; rather, the ratemaking treatment determined by the Commission drives financial accounting.

Capital Structure, Cost of Capital, and Overall Rate of Return

30. As set forth in Section III.B of the Second Partial Stipulation, the Public Staff and the Company agreed on a capital structure consisting of 52% common equity and 48% long-term debt.

31. The Company’s embedded cost of debt is 4.27%, as set forth in Section III.B of the Second Partial Stipulation.

32. As set forth in Section III.B of the Second Partial Stipulation, the Company and the Public Staff agreed that the Company should be allowed the opportunity to earn a rate of return on common equity (ROE) of 9.60%.

33. The overall rate of return that the Company should be allowed the opportunity to earn on the cost of the Company's used and useful property is 7.04%.

34. The overall rate of return and ROE are supported by competent, material, and substantial evidence; are consistent with the requirements of N.C.G.S. § 62-133 in light of changing economic conditions; and appropriately balance the Company's need to maintain the safety, adequacy, and reliability of its service with the benefits received by DEC's customers from safe, adequate, and reliable electric service.

35. The capital structure, ROE, and overall rate of return set by this Order will result in just and reasonable rates.

Cost of Service Adjustments

36. The agreed-upon accounting adjustments outlined in McManeus Supplemental Rebuttal Exhibit 3, McManeus Second Settlement Exhibit 3, Boswell Supplemental and Stipulation Exhibit 1, Schedule 1, and Boswell Second Supplemental and Stipulation Exhibit 1, Schedule 1 (Partial Stipulation Revenue Requirement Exhibits) are just and reasonable to all parties in light of all the evidence presented.

Deferral of Grid Improvement Plan Capital Costs

37. DEC requested deferral of approximately $1.3 billion in spending to occur from January 2020 through 2022 on its GIP.

38. As a result of DEC's Second Partial Stipulation with the Public Staff and settlements with other parties, DEC narrowed the scope of the programs for which the Company seeks capital cost deferral and reduced its request to approximately $800 million in GIP spending from June 2020 through 2022.

39. DEC's reduced GIP deferral request as set forth in the Second Partial Stipulation is reasonable and should be approved subject to limitation.

40. DEC has the burden of proving that its GIP spending is reasonable and prudent when it seeks to recover, in any future proceeding, GIP costs from customers.

41. GIP expenditures beyond those covered by the GIP deferral approved herein are to be informed by the Integrated System Operations Planning (ISOP) process.

Tax Act Issues

42. Federal protected EDIT should be removed from DEC's proposed rider and amortized through base rates in accordance with the Internal Revenue Service (IRS) normalization rules as DEC agreed in the First Partial Stipulation.

43. The federal unprotected EDIT should be flowed back to customers using a levelized five-year rider as DEC agreed in the Second Partial Stipulation.

44. The federal provisional revenues should be flowed back to customers using a levelized two-year rider as DEC agreed in the Second Partial Stipulation.

45. State EDIT should be flowed back to customers using a levelized two-year rider as DEC agreed in the Second Partial Stipulation.

46. The provisions of the CIGFUR Stipulation regarding the appropriate methodology to flow back unprotected EDIT and provisional revenues are not just and reasonable and should not be approved.

47. All federal unprotected EDIT and provisional revenues should be refunded to customers using the methodology based on the amounts each class paid, and specifically, as a credit by specific customer class divided by the adjusted class' test year sales, as recommended by Public Staff witness Floyd.

48. The agreement between DEC and the Public Staff in the Second Partial Stipulation concerning how to address changes in the federal corporate income tax rate and the North Carolina state corporate income tax rate which may occur during the respective amortization periods is reasonable and appropriate.

Cost Allocation Methodology

49. In the Second Partial Stipulation the Company and the Public Staff agreed to calculate and allocate the Company's cost of service based on a Summer Coincident Peak (SCP) cost-of-service methodology to determine the Company's North Carolina jurisdictional and retail customer class cost allocation and responsibility.

50. As set forth in the CIGFUR Stipulation, the Company has committed to file in its next general rate case the results of a class cost-of-service study with production and transmission costs allocated on the basis of the Summer/Winter Coincident Peak method and to consider such results for the sole purpose of apportionment of the change in revenue to the customer classes.

Rate Design

51. It is appropriate for the Company to conduct a comprehensive rate design study as agreed to in the Second Partial Stipulation and expanded on in this Order.

Affordability

52. It is appropriate for the Company to convene a stakeholder process tasked with addressing affordability issues for low-income residential customers as DEC agreed in the NCSEA/NCJC et al. Stipulation and the Second Partial Stipulation.

53. It is appropriate for the Company to provide, in conjunction with the concurrent commitment of DEP, an aggregate combined shareholder-funded contribution to the Helping Home Fund of $3 million per year for two years (for a total of $6 million) which will not affect rates as DEC agreed in the NCSEA/NCJC et al. Stipulation.

54. It is appropriate for the Company to make an annual $2.5 million shareholder contribution to the Share the Warmth Fund in 2021 and 2022 (for a total of $5 million) which will not affect rates as DEC agreed in the Second Partial Stipulation.

Storm Costs

55. The costs incurred by DEC to respond to Hurricanes Florence and Michael and Winter Storm Diego (Storm Costs) as presented by the Company and agreed to in the First Partial Stipulation are just and reasonable and were prudently incurred to the extent such costs represent actual amounts as of May 31, 2020. Any estimated costs as of that date or incurred afterward remain subject to review pursuant to the provisions of N.C.G.S. § 62-172(a)(14)(c).

56. DEC's Storm Costs total $213.1 million, consisting of approximately $169.8 million in actually incurred or projected storm response operations and maintenance (O&M) costs, approximately $18.6 million in capital investments, and approximately $24.7 million in carrying costs calculated using the Company's approved weighted average cost of capital through July 31, 2020.

57. Consistent with the First Partial Stipulation and the testimony of witness De May, DEC has withdrawn the Storm Costs, including capital investments, from the current rate case, except for purposes of the prudence determination reached in Finding of Fact No. 55.

58. It is appropriate that DEC continue to defer the Storm Costs in a regulatory asset account until the date storm cost recovery bonds are issued pursuant to an approved financing order in accordance with N.C.G.S. § 62-172 or until the Company seeks recovery of the Storm Costs through an alternative method of cost recovery.

59. It is appropriate that DEC continue to accrue and record carrying costs at the Company's approved weighted average cost of capital on the deferred balances in its storm cost recovery deferral account pending recovery through securitization, subject to the assumptions and conditions agreed to in the First Partial Stipulation.

60. A ten-year normalized adjustment to DEC's revenue request to account for anticipated storm expenses that are too small to securitize is appropriate for use in this proceeding.

61. It is appropriate to establish a Storm Cost Recovery Rider for the Company and to set the initial balance for that rider at $0 in conformance with the provisions of the First Partial Stipulation.

Adjustments to Plant in Service

62. The capital costs associated with the Lincoln County Combustion Turbine 17 (LCCT 17) project should be removed from the rate base.

63. The capital costs associated with Project Focal Point 12 should be removed from rate base.

Prepaid Advantage Program

64. The Company's proposed Prepaid Advantage Program, with conditions as set forth herein, is reasonable and in the public interest.

AMI and Green Button Connect

65. DEC's costs of deploying AMI meters were prudently incurred and are reasonable.

66. It is appropriate for DEC to recover from all customers Rider MRM costs not recovered from customers opting out of AMI meters.

67. The question of whether DEC should implement Green Button "Connect My Data" should be addressed in the ongoing investigation and rulemaking in Docket No. E-100, Sub 161.

Service Regulations, Vegetation Management, and Quality of Service

68. The amendments to the service regulations proposed by the Company are reasonable and should be approved.

69. DEC's annual target for distribution system vegetation management has increased from 6,177 to 6,187 miles. DEC's annual target for distribution system vegetation management of 6,187 miles is an increase from the 5,559 miles trimmed in the test year. DEC's outside labor expense for vegetation management contract work has increased by 3%. It is therefore appropriate to adjust DEC's vegetation management annual expense for these factors, subject to the Public Staff's corrected cost per mile adjustment.

70. With the adjustment in Finding of Fact No. 69, DEC's vegetation management plan is reasonable.

71. The overall quality of service provided by DEC is good.

Accounting for Deferred Costs

72. The Company is authorized to receive a specific amount of revenue for each of the deferred costs approved by this Order. If DEC receives revenue for any deferred cost for a longer period of time than the amortization period approved by the Commission for that deferred cost, the Company shall continue to record all revenue received for that deferred cost in the specific regulatory asset account established for that deferred cost until the Company's next general rate case.

Just and Reasonable Rates

73. The base non-fuel and base fuel revenues and rates approved herein are just and reasonable for the customers of DEC, DEC, and all parties to this proceeding, and serve the public interest.

Revenue Requirement

74. After giving effect to the portions of the settlement agreements approved herein and the Commission's decisions on contested issues, the annual revenue requirement for DEC will allow the Company a reasonable opportunity to recover its operating costs and earn the rate of return on its rate base that the Commission has found to be just and reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1–3

Stipulations

The evidence supporting these findings of fact is found in the verified Application and Form E-1, the stipulations between DEC and other parties, the testimony and exhibits of DEC witness De May and Public Staff witness Boswell, and the entire record in this proceeding.

Summary of the Evidence

Public Staff First and Second Partial Stipulations

On March 25, 2020, DEC and the Public Staff entered into and filed the First Partial Stipulation resolving some of the issues in this proceeding between the two parties and delineating those issues for which they had not reached compromise (Unresolved Issues). On July 31, 2020, the Public Staff and the Company entered into and filed the Second Partial Stipulation resolving several additional issues in this proceeding.

The First Partial Stipulation is based on the same test period as the Company's Application, adjusted for certain known changes in revenue, expenses, and rate base through January 31, 2020. The Second Partial Stipulation is based upon the same test period as the Company's Application, adjusted for certain known changes in revenue, expenses, and rate base through January 31, 2020, and May 31, 2020 (May 2020 Updates).

The Second Partial Stipulation outlines the remaining Unresolved Issues as follows: (1) cost recovery of the Company's coal ash costs, recovery amortization period, and return during the amortization period; (2) amortization period for the loss on the sale of the hydro stations; (3) depreciation rates appropriate for use in this case; and (4) any other revenue requirement or nonrevenue requirement issue other than those issues specifically addressed in the Second Partial Stipulation, the First Partial Stipulation, or agreed upon in the testimony of DEC and the Public Staff. Second Partial Stipulation, § II.

Witness De May explained that the First Partial Stipulation resolves several of the revenue requirement issues between the Company and the Public Staff. Tr. vol. 11, 879. Revenue requirement adjustments were agreed upon in the First Partial Stipulation for Storm Costs, aviation expenses, executive compensation and benefits, board of directors, lobbying, sponsorships and donations, rate case expenses, severance, incentive compensation, retired hydro O&M expenses, credit card fees, advertising, weather normalization, growth and usage, and protected federal EDIT. *Id.* These accounting and ratemaking adjustments and the resulting revenue requirement effect of the First Partial Stipulation are shown in Schedule 1 of Boswell Supplemental and Stipulation Exhibit 1, and McManeus Supplemental Rebuttal Exhibit 3, which provide sufficient support for the annual revenue required on the issues agreed to in the First Partial Stipulation. The revenue requirement impact of the issues settled in the First Partial Stipulation is a reduction of the base revenue requirement from that requested in the Application of approximately $78,878,000 to $81,049,000, depending on the resolution of the Unresolved Issues.

The Public Staff's prefiled testimony expressed concerns about certain aspects of the Company's recordkeeping and reporting practices. The stipulating parties resolved these concerns in the Second Partial Stipulation. Section IV.J provides that within 90 days after the Commission issues its final order herein the Company will work with the Public Staff on document retention, project reporting, and other reasonably applicable matters to better assist the Public Staff in future audits of plant. In addition, Section IV.K states that DEC will have its internal Corporate Audit Services conduct an independent review/audit of its materials and supply inventory, and that the terms of the audit should, at a minimum, meet those recommended in the direct testimony of Public Staff witness Metz. Further, Section IV.L of the Second Partial Stipulation provides that DEC and the Public Staff will meet to discuss the Company's plant unitization policies and reach agreement on the Company's reporting obligations.

Witness De May testified that the Second Partial Stipulation resolves most, but not all of the remaining revenue requirement issues between DEC and the Public Staff. Tr. vol. 11, 884. Witness De May provided an overview of the major components of the

Second Partial Stipulation, including an agreement regarding shareholder contributions to the Share the Warmth Program, cost of capital, return of state and federal EDIT to customers, deferral accounting treatment of certain GIP programs, cost-of-service methodology for this case, inclusion of the May 2020 Updates to certain pro forma adjustments subject to the Public Staff's audit of the updates and other terms concerning the May 2020 Updates, the amount of recovery for the Clemson CHP project, and the amortization period for non-ARO environmental costs. *Id.* at 884-87.

In addition, witness De May outlined other areas of agreement, including terms governing the start date of the evidentiary hearings to allow time for the Public Staff to audit the May 2020 Updates, ongoing assessments of the cost effectiveness of GIP-related projects, clarification of GIP costs that are eligible for deferral, commitments to future cost-of-service studies, rate design issues, and commitments to conduct audits and reporting obligations regarding plant and materials and supplies inventory. *Id.* at 887. These accounting and ratemaking adjustments and the resulting revenue requirement effect of the Second Partial Stipulation are shown in Boswell Second Supplemental and Stipulation Exhibit 1, Schedule 1, and McManeus Second Settlement Exhibit 2, which provide sufficient support for the annual revenue required on the issues agreed to in the Second Partial Stipulation. The Company's calculation of the revenue requirement impact of the issues settled in the Second Partial Stipulation is an increase in the base revenue requirement of approximately $46,798,000, to be further adjusted by the Public Staff's recommendations in its September 8, 2020 testimony, and pending resolution of the Unresolved Issues. However, the stipulating parties could not determine the total impact to base rate revenues without the Commission's final determination of the Unresolved Issues.

Witness De May testified that he attended public hearings held by the Commission in this matter and personally heard from dozens of customers who are concerned about the impacts of any rate increase on their families and businesses, and he noted that the Company is very mindful of these concerns. *Id.* at 881-82, 887-88. Witness De May stated that the concessions the Company has made in the First and Second Partial Stipulations fairly balance the needs of customers with the Company's need to recover investments made to continue to comply with regulatory requirements and safely provide high quality electric service to its customers, particularly so in the Second Partial Stipulation in light of the current economic conditions of many of the Company's customers due to the COVID-19 pandemic. *Id.* at 882, 888.

Public Staff witness Boswell testified that from the perspective of the Public Staff, the most important benefits provided by the Public Staff Partial Stipulations are: (1) an aggregate reduction in the Company's proposed revenue increase as to specific expense items agreed to by DEC and the Public Staff in this proceeding, and (2) the avoidance of protracted litigation between DEC and the Public Staff before the Commission and possibly the appellate courts. Tr. vol. 17, 276, 286. Based on these ratepayer benefits, as well as the other provisions of the Public Staff Partial Stipulations, the Public Staff believes the Public Staff Partial Stipulations are in the public interest and should be approved. *Id.*

Section III of the First Partial Stipulation outlines a number of accounting adjustments to which DEC and the Public Staff have agreed as well as Section III.J. of the Second Partial Stipulation. These accounting adjustments are fully discussed later in this Order.

CIGFUR Stipulation

On May 29, 2020, the Company and CIGFUR entered into and filed the CIGFUR Stipulation. No testimony supporting the settlement was filed.

As part of the CIGFUR Stipulation, DEC initially agreed that the revenues to be approved in this proceeding should be adjusted to provide the Company, through sound management, the opportunity to earn an ROE of 9.75% and that this ROE will be applied to the common equity component of the ratemaking capital structure consisting of 52% equity and 48% long-term debt. CIGFUR Stipulation, § II. Subsequently, on August 6, 2020, the Stipulation was amended to state that should the Commission approve an ROE of 9.60% applied to a capital structure of 52% equity, 48% debt, this section of the stipulation should be deemed to be fulfilled.

In addition, CIGFUR agreed to support the Company's request for a deferral of GIP costs over three years. CIFGUR Stipulation, § III.A. Because the three-year GIP plan contains estimates, CIGFUR's support for the GIP deferral will be subject to a reservation of its rights to review and object to the reasonableness of specific project costs in future rate cases. To the extent that DEC enters into an agreement with other intervening parties agreeing to a cost cap or to otherwise limit the maximum allowed amount of the three-year GIP deferral, CIGFUR supports such cost containment measures.

Section III.B of the CIGFUR Stipulation provides that in the next rate case DEC will propose to allocate the deferred GIP costs among classes consistent with its distribution cost allocation methodologies proposed in this docket, including use of the minimum system methodology (MSM) and voltage-differentiated allocation factors for distribution plant. Additionally, with Commission approval, the Company will use this methodology to allocate GIP costs during the three years for which it may seek recovery in future rate cases.

Under Section IV, the parties agreed to refund unprotected EDIT on a uniform cents per kilowatt-hour (cents/kWh) basis.

Under Section V, DEC and CIGFUR agreed to five conditions related to cost of service and rate design. The first condition would obligate DEC to discuss and consider potential cost-of-service methodologies and to consider the results of a cost-of-service study based on the Summer/Winter Coincident Peak method. The second condition would require DEC in its next rate case to adjust peak demand to remove curtailable/non-firm load, even when the load reduction is not requested. The third condition would require DEC in its next two fuel proceedings to propose the uniform percentage average bill adjustment methodology. The fourth condition would require DEC in its next three rate cases to allocate distribution expenses using the MSM unless the Commission rejects the method. The fifth condition would require the Company to explore certain rate designs and file the rates if there is interest from CIGFUR customers.

Harris Teeter/Commercial Group Stipulations

DEC and Harris Teeter entered into and filed the HT Stipulation on May 28, 2020, and DEC and the Commercial Group entered into and filed the CG Stipulation on June 1, 2020. These settlements are substantially similar, and they resolve several issues between DEC and these two parties, including ROE and capital structure, GIP, and some rate design issues. No testimony supporting either settlement was filed.

As part of the HT and CG Stipulations, DEC initially agreed that the revenues to be approved in this proceeding should be adjusted to provide the Company, through sound management, the opportunity to earn an ROE of 9.75% and that this ROE will be applied to the common equity component of the ratemaking capital structure consisting of 52% equity and 48% long-term debt. HT Stipulation, § 4; CG Stipulation, § 4. Subsequently, both stipulations were amended to state that should the Commission approve an ROE of 9.60% applied to a capital structure of 52% equity, 48% debt, this section of each stipulation should be deemed to be fulfilled.

As part of its stipulation with DEC, the Commercial Group neither opposes nor specifically supports the approval of the Company's requested GIP deferral. CG Stipulation, § 1. Harris Teeter supports the approval of the Company's requested GIP deferral with certain conditions detailed therein, including a reservation of Harris Teeter's right to take any position as to the reasonableness of specific GIP costs in a future rate case. HT Stipulation, § 1.

Further, DEC, Commercial Group, and Harris Teeter agreed that any GIP costs allocated to OPT-V customers will be recovered through OPT-V demand charges. They also agreed that the OPT-VSS off-peak energy charge shall be set at 3.0222 cents/kWh and the on-peak energy charge shall be increased by a percentage amount that is equal to half of the overall percentage increase for the OPT-VSS rate schedule. HT Stipulation, § 3; CG Stipulation, § 3. In addition, the settlements provide that the demand charges for the OPT-VSS rate schedule shall be adjusted by the amount necessary to recover the final OPT-VSS revenue target. *Id.*

Pursuant to Section 5 of the CG Stipulation, Commercial Group agreed that the Company has met with its representatives and adequately addressed its concerns.

NCSEA/NCJC et al. Stipulation

On May 29, 2020, DEC, NCSEA, and NCJC et al. entered into and filed the NCSEA/NCJC et al. Stipulation resolving some of the issues in this proceeding between these parties. No testimony supporting the settlement was filed.

As part of the NCSEA/NCJC et al. Stipulation, the parties initially agreed that the revenues to be approved in this proceeding should be adjusted to provide the Company, through sound management, the opportunity to earn an ROE of 9.75% and that this ROE will be applied to the common equity component of the ratemaking capital structure consisting of 52% equity and 48% long-term debt. NCSEA/NCJC et al. Stipulation, § II. Subsequently, on August 10, 2020, the parties filed an amendment to their stipulation providing that should the Commission approve an ROE of 9.60% applied to a capital structure of 52% equity, 48% debt, this section of the stipulation should be deemed to be fulfilled.

NCSEA and NCJC et al. also agreed to support the Company's request for an accounting order for approval to defer GIP costs for investments in ISOP, Integrated Volt Var Control (IVVC), Self-Optimizing Grid (SOG), Distribution Automation, Transmission System Intelligence, the Distributed Energy Resources (DER) Dispatch Tool, and the 44-kV Line Rebuild. NCSEA and NCJC et al. believe that these investments will directly enable and support the greater utilization of DERs on the Company's system. For all other GIP investments proposed by DEC, NCSEA and NCJC et al. do not oppose the requested deferral accounting treatment. To the extent that DEC enters into an agreement with other intervening parties agreeing to a cost cap or to limit the amount of any GIP investment category specified for deferral treatment, NCSEA and NCJC et al. support such cost containment measures, subject to a reservation of their rights to review and object to the reasonableness of specific project costs in future rate cases.

Pursuant to other provisions of the NCSEA/NCJC et al. Stipulation, DEC agreed:

(1) to provide, in conjunction with the concurrent commitment of DEP, an aggregate combined shareholder-funded contribution to the Helping Home Fund of $3 million per year for two years (for a total of $6 million);

(2) that within six months of the effective date of the stipulation, in addition to the low-income collaborative proposed by DEC, to collaborate with NCSEA and NCJC et al. to design additional low-income EE/DSM program pilots to present to the DEC and DEP EE/DSM Collaborative for consideration; and further, on the condition that the majority of EE/DSM Collaborative participants and DEP and DEC support the program pilots, to file for approval of the program pilots in North Carolina and South Carolina; and

(3) within six months of the effective date of the stipulation, to collaborate with NCSEA and NCJC et al. to design a tariffed on-bill pilot program, which shall include a Pay-As-You-Save or other mutually agreeable alternative program design, for customers in North Carolina, addressing several listed issues; and further, within 18 months of the effective date of the agreement, to either (i) file the pilot for approval with the Commission, provided the parties mutually agree to the terms of the pilot program that is not less than three years in length and, in conjunction with the concurrent commitment of DEP, includes a combined total of no fewer than 700 but no more than 1000 residential customers, or (ii) file a status report with the Commission in this docket.

In addition, DEC agreed to preview a Distributed Generation Guidance Map for North Carolina with the DER Interconnection Technical Standards Review Group (TSRG) in the TSRG meeting during the third quarter of 2020, as well as in the August 2020 ISOP stakeholder meeting, after which DEC will incorporate TSRG and ISOP stakeholder input as appropriate and publish the Distributed Generation Guidance Map for North Carolina.

Further, DEC agreed to include in its 2021 IRP details about how both existing and new DERs and non-wires applications will be examined in its ISOP as means to defer traditional capital investments in the system. DEC also agreed to implement the basic elements of the ISOP process in the 2022 IRP. Following the 2024 IRP, but no later than December 31, 2024, DEC agreed to provide hosting capacity analyses for a representative sample of DEC North Carolina circuits with other provisions and contingencies.

In addition, DEC agreed that it will reasonably include NCSEA and NCJC et al. for input and feedback at material points in its selection process as it identifies the tools and capabilities necessary for ISOP implementation. DEC also agreed to reasonably consider and, where appropriate, incorporate input from the parties with regard to the parameters that ISOP will use to assess issues such as distribution investment needs, the use of existing and future distributed energy resources and non-wires applications, load forecasts, pricing assumptions, and modeling inputs, keeping in mind the overall objective of developing investment plans that meet customer needs and preferences by capturing efficiencies from being a vertically integrated electric utility.

Vote Solar Stipulation

DEC and Vote Solar entered into and filed the Vote Solar Stipulation on June 9, 2020, resolving some of the issues in this proceeding between these parties. No testimony supporting the settlement was filed.

As part of the Vote Solar Stipulation, DEC initially agreed that the revenues to be approved in this proceeding should be adjusted to provide the Company, through sound management, the opportunity to earn an ROE of 9.75% and that this ROE will be applied to the common equity component of the ratemaking capital structure consisting of 52% equity and 48% long-term debt. Vote Solar Stipulation, § II. Subsequently, on August 5, 2020, the parties filed an amendment to the Vote Solar Stipulation, providing that should the Commission approve an ROE of 9.60% applied to a capital structure of 52% equity, 48% debt, this section of the stipulation should be deemed to be fulfilled.

Further, Vote Solar agreed to support the Company's request for an accounting order for approval to defer GIP costs for investments in ISOP, IVVC, SOG, Distribution Automation, Transmission System Intelligence, the DER Dispatch Tool, and the 44-kV Line Rebuild. Vote Solar believes that these investments will directly enable and support the greater utilization of DERs on the Company's system. For all other GIP investments proposed by DEC, Vote Solar does not oppose the requested deferral accounting treatment. To the extent that DEC enters into an agreement with other intervening parties agreeing to a cost cap or to limit the amount of any GIP investment category specified for deferral treatment, Vote Solar supports such cost containment measures. Further, Vote Solar's support for the GIP deferral is subject to a reservation of its rights to review and object to the reasonableness of specific project costs in future rate cases.

In addition, DEC committed with Vote Solar to develop potential pilot customer programs prior to the submission of the 2022 IRP to optimize the capability of the GIP investments to support greater utilization of DERs, including customer-sited solar and/or storage facilities (e.g., net metering successor), microgrid systems that benefit and would be paid for by specific benefitted customers, and programmable and load controllable devices or appliances for use in residential and nonresidential demand response programs. If DEC and Vote Solar mutually agree that these programs are cost-effective and meet appropriate Commission requirements, DEC agreed to file such pilot programs for approval by the Commission, and Vote Solar agreed to support such approval by the Commission.

Moreover, DEC agreed that within six months from the effective date of the Commission's order in this docket, DEC will convene a Climate Risk & Resilience Working Group (Working Group) governed by several parameters set out in the stipulation. Within 60 days of the effective date of the Commission's order the Company will make an informational filing in the docket to describe its scoping plan and proposed schedule for the Working Group and will give notice of such filing to all interested parties in all North Carolina and South Carolina dockets and stakeholder processes to which it is a party related to climate or decarbonization policy, the GIP, IRP, and ISOP. DEC further agreed to fund a third-party consultant with experience developing models or analyses for quantifying climate-related impacts on the electric grid to assist stakeholders and the Company with the Working Group, subject to the contingency that DEC will recover the cost of the third-party consultant from ratepayers.

Discussion and Conclusions

As none of the partial stipulations have been adopted by all of the parties to this docket, the Commission's determination of whether to accept or reject each of the stipulations is governed by the standards set out by the North Carolina Supreme Court in *State ex rel. Utilities Commission v. Carolina Utility Customers Ass'n, Inc.*, 348 N.C. 452, 500 S.E.2d 693 (1998) (*CUCA I*), and *State ex rel. Utilities Commission v. Carolina Utility Customers Ass'n, Inc.*, 351 N.C. 223, 524 S.E.2d 10 (2000) (*CUCA II*). In *CUCA I*, the Supreme Court held:

> [A] stipulation entered into by less than all of the parties as to any facts or issues in a contested case proceeding under chapter 62 should be accorded full consideration and weighed by the Commission with all other evidence presented by any of the parties in the proceeding. The Commission must consider the nonunanimous stipulation along with all the evidence presented and any other facts the Commission finds relevant to the fair and just determination of the proceeding. The Commission may even adopt the recommendations or provisions of the nonunanimous stipulation as long as the Commission sets forth its reasoning and makes "its own independent conclusion" supported by substantial evidence on the

record that the proposal is just and reasonable to all parties in light of all the evidence presented.

348 N.C. at 466, 500 S.E.2d at 703.

However, as the Court made clear in *CUCA II*, the fact that fewer than all of the parties have adopted a settlement does not permit the Court to subject the Commission's Order adopting the provisions of a nonunanimous stipulation to a "heightened standard" of review. 351 N.C. at 231, 524 S.E.2d at 16. Rather, Commission approval of the provisions of a nonunanimous stipulation "requires only that the Commission ma[k]e an independent determination supported by substantial evidence on the record [and] . . . satisf[y] the requirements of chapter 62 by independently considering and analyzing all the evidence and any other facts relevant to a determination that the proposal is just and reasonable to all parties." *Id.* at 231-32, 524 S.E.2d at 16.

The Commission finds and concludes that the provisions of the First and Second Partial Stipulations, as well as the stipulations with CIGFUR, Harris Teeter, Commercial Group, Vote Solar, NCSEA, and NCJC et al. result from the give-and-take between DEC and the stipulating parties and represent a compromise that is fair and adequate to each stipulating party. Pursuant to *CUCA I* and *II*, these nonunanimous stipulations are some evidence to be considered by the Commission in reaching its decision in this case. The Commission has fully evaluated the provisions of these stipulations and concludes, in the exercise of its independent judgment, that the stipulations should be accepted, in part, and rejected, in part, consistent with the specific discussion and resolution of the various issues discussed below. The parties are free to enter into stipulated provisions that pertain to actions or positions to be taken outside the confines of this proceeding; however, to the extent that DEC committed to certain actions or positions in future proceedings, the Commission concludes that they are not relevant to any issue before the Commission in this case and do not tie the Commission's hands or limit future investigations.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

Base Fuel and Fuel-Related Cost Factors

The evidence supporting this finding of fact is found in the verified Application and Form E-1, the Public Staff Second Partial Stipulation, the testimony and exhibits of DEC witnesses McGee and McManeus and Public Staff witnesses Metz and Boswell, and the entire record in this proceeding.

Summary of the Evidence

In her direct testimony Company witness McGee supported the fuel component of the proposed base rates for all customer classes and the fuel pro forma adjustments to the test year operating expenses contained in McManeus Direct Exhibit 1. Tr. vol. 11, 749-50. Witness McGee proposed to use the total prospective fuel and fuel-related costs factors proposed on February 26, 2019, in Docket No. E-7, Sub 1190. *Id.* at 749. Witness

McGee explained that DEC's intent in using the fuel-related costs factors that were proposed at the time the Company's Application was prepared as a component of its proposed new rates was to make it clear that the Company is requesting a rate increase that relates to non-fuel revenues only. *Id.* at 749-50.

In his direct testimony Public Staff witness Metz testified that based on his review of the Company's base fuel factor, the base fuel factor was appropriate and aligned with the Company's proposed and Commission-approved previous annual fuel filing, Docket No. E-7, Sub 1190. Tr. vol. 16, 675.

The Company filed its subsequent fuel factor adjustment case in Sub 1228 on February 25, 2020. Section IV.N of the Second Partial Stipulation provides that should a final Commission order be issued in the fuel rider proceeding prior to the due date for proposed orders in this general rate case proceeding, the total of the approved base fuel and fuel-related costs factors, by customer class, will be the sum of the respective base fuel and fuel-related costs factors set in Sub 1146 and the annual non-EMF fuel and fuel-related costs riders approved by the Commission in Sub 1228. Company witness McManeus and Public Staff witness Boswell supported the provision for the total approved base fuel and fuel related costs factors through their testimony in support of the Second Partial Stipulation. Tr. vol. 11, 581-82; tr. vol. 17, 284-86.

The Commission issued a final Order in the Sub 1228 fuel rider proceeding on August 19, 2020. In that order the Commission concluded that effective for service rendered on and after September 1, 2020, DEC shall reduce the base fuel and fuel-related costs in its North Carolina retail rates of 1.7828 cents/kWh, 1.9163 cents/kWh, and 2.0207 cents/kWh for the residential, general service/lighting, and industrial classes, respectively, as approved in Sub 1146, by amounts equal to (0.1801) cents/kWh, (0.1580) cents/kWh, and (0.3555) cents/kWh for the residential, general service/lighting, and industrial classes, respectively. These adjustments result in total base fuel and fuel-related costs of 1.6027 cents/kWh, 1.7583 cents/kWh, and 1.6652 cents/kWh for the residential, general service/lighting, and industrial classes, respectively.

According to witness McGee, the Company will continue to bill customers the fuel rates authorized by the Commission in its 2020 annual fuel proceeding. Tr. vol. 11, 751. As such, there will be no change in customers' bills as a result of including these fuel cost factors in the proposed base rates. *Id.*

Discussion and Conclusions

No intervenor offered any evidence contesting the testimony of Company and Public Staff witnesses in support of the base fuel and fuel-related costs factors therein or the provision in the Second Partial Stipulation for the Company's base fuel and fuel-related costs factors. Further, the Commission gives significant weight to Section IV.N of the Second Partial Stipulation regarding the base fuel and fuel-related costs factors. Accordingly, the Commission finds and concludes for purposes of this proceeding that the total of the approved base fuel and fuel-related costs factors, by customer class — the sum of the respective base fuel and fuel-related costs factors set in Sub 1146 and the annual non-EMF fuel and fuel-related costs riders approved by the Commission in Sub 1228 — are just and reasonable to all parties in light of all the evidence presented.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5–7

Amortization of Loss on Hydro Station Sale

The evidence supporting these findings of fact is found in the verified Application and Form E-1, the testimony and exhibits of DEC witness McManeus and Public Staff witness Boswell, and the entire record in this proceeding.

Summary of the Evidence

In her direct testimony Company witness McManeus explained that the Company had removed test period operating expenses and rate base amounts related to five hydro stations that were sold on August 16, 2019. Tr. vol. 11, 484. She testified that the Commission approved the sale of the facilities and the transfer of the related certificates of public convenience and necessity in Docket Nos. E-7, Sub 1181, SP-12478, Sub 0, and SP-12479, Sub 0 (Sub 1181). *Id.* In addition, the Commission in those dockets approved the establishment of a regulatory asset for the estimated loss on disposition of the facilities and ordered that the amortization of the regulatory asset begin at the time the sale is closed. *Id.* In an effort to closely align the revenue requirement associated with the loss on the sale to the revenue requirement amount associated with ownership of the facilities, the Company proposed to amortize the estimated loss on the sale over a seven-year period. *Id.* at 485. In her supplemental direct testimony, witness McManeus updated the adjustment, which was based on estimated values, to reflect final accounting entries related to completion of the sale. *Id.* at 508.

Public Staff witness Boswell recommended the deferred loss on the sale of the hydro assets be amortized over 20 years, which would have been the remaining depreciable life of the assets if they had remained in service. Tr. vol. 17, 257. Witness Boswell noted that in its filing for deferral accounting in Sub 1181, the Company asserted that the sale transaction would allow the facilities to continue to serve the customers with clean renewable energy, but at a lower cost. Witness Boswell also noted that the cost-benefit analysis provided by the Company in the Sub 1181, docket was based on the 20-year costs to maintain and operate the facilities and that in the Public Staff's comments and testimony in that docket, the Public Staff had also recommended a 20-year amortization period. *Id.* According to witness Boswell, at the time the Public Staff's comments were filed in Sub 1181, the average remaining life of the facilities was 22.49 years; as of the end of 2019 the remaining depreciable life was 19.95 years. *Id.*

In her rebuttal testimony Witness McManeus stated that she believes the Company's recommended seven-year period is fair because "[t]he revenue requirement resulting from the annual amortization expense using the 7-year amortization period as proposed by the Company closely aligns with the amount of revenue requirement associated with test period annual O&M expense and annual depreciation expense of the hydro units being sold, resulting in minimal change to existing rates." Tr. vol. 11, 523.

Witness McManeus was asked during cross-examination whether customers would experience a decrease in rates in the present proceeding if the loss on the sale of the hydro units was amortized over 20 years as proposed by the Public Staff as opposed to seven years. Witness McManus responded that if something is amortized over seven years the amortization amount is higher than amortizing it over 20 years. Tr. vol. 15, 124. Witness McManeus further testified that the seven-year period was "backed into," taking a bit of guidance from the Commission's order in Sub 1181. *Id*. at 123. In that order, when the Commission approved the deferral of the loss, it also indicated that the amortization amount should be equal to the depreciation expense and thereby provide rate neutrality. *Id*. at 123-24.

On request of counsel for the Public Staff, the Commission took judicial notice of the Commission's June 5, 2019 order in Sub 1181. Tr. vol. 15, 120. In Sub 1181 the Commission noted that it would address the amortization period for the remaining regulatory asset and whether the regulatory asset should earn a return in DEC's next general rate case. No party provided testimony in this proceeding opposing a return.

Discussion and Conclusions

Based on the foregoing and the record, the Commission finds that it is appropriate to accept and adopt the recommendation of the Public Staff. In reaching this conclusion the Commission gives significant weight to Public Staff witness Boswell's testimony and the Commission's June 5, 2019 order issued in Sub 1181. It is undisputed that the purpose of the sale of the hydro units was to enable the Company to supply its customers with electric service based on least-cost principles. The Commission ordered in Sub 1181 that the Company amortize the loss on sale (i.e., the "stranded cost" of the hydro facilities) over the 20-year remaining depreciation period until further order of the Commission. The rationale underlying that decision was the fact that the Company was already recovering costs of the plants in its rates based on the 20-year period. However, in its Sub 1181 order, the Commission held that it would decide the amortization period for the remaining regulatory asset and whether a return on the unamortized balance would be authorized in DEC's next general rate case.

The current case is that next general rate case and presents the Commission with a different situation than in Sub 1181 — an opportunity to change DEC base rates to reflect a fair and reasonable distribution of the net benefits of the hydro sale. The Commission concludes that amortizing the stranded costs over a seven-year period in this case will not reflect a fair and reasonable distribution. Amortizing the stranded costs, recovery of which reduces the net benefits to be enjoyed by customers, over a seven-year period rather than a 20-year period would unreasonably skew the benefits from the sale of the assets toward customers in later years at the expense of customers in earlier years. The Commission finds that the Company has not presented evidence in the present case that amortization over a seven-year period would provide ratepayers with the reasonable benefits of the sale and deferral presented in Sub 1181. The Commission finds and concludes that a 20-year amortization period will result in a more just and fair distribution of benefits over the years that the overall transaction is expected to produce net benefits. The Commission thus concludes that the 20-year amortization period as recommended by the Public Staff should be approved in this proceeding.

Regarding the question of a return, the Commission will allow the Company to earn a return on the unamortized balance as the hydro stations were sold to Northbrook to provide a benefit to customers. Significantly, in its Sub 1181 order, the Commission found that "as part of the Transaction DEC has agreed to purchase all of the energy and RECs generated by the Facilities for five years following the Transaction through renewable power purchase power agreements (RPPAs) with Northbrook. As such, the Facilities will continue to serve customers with clean renewable energy, but at a lower cost over time." Furthermore, no party has opposed the Company's earning a return on the unamortized balance in this proceeding. For these reasons, the Commission finds it is appropriate to allow a return on the unamortized balance of the regulatory asset representing the hydro stations that were sold.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 8–13

Depreciation Study

The evidence supporting these findings of fact is found in the verified Application and Form E-1, the testimony and exhibits of DEC witness Spanos and Public Staff witness McCullar, and the entire record in this proceeding.

Summary of the Evidence

DEC Direct Testimony

DEC witness Spanos provided a copy of the new deprecation study he prepared for DEC for use in this proceeding as Exhibit 1 to his prefiled direct testimony. Witness Spanos testified as to how he determined the depreciation rates included in the depreciation study. He further testified that he used the same methods and procedures to produce the current depreciation study as he has done in previous DEC depreciation studies. Tr. vol. 12, 140.

Next, witness Spanos discussed the life span estimates for DEC's production facilities. Id. at 139-41. He stated that the life span estimates are based on informed judgment that incorporates factors for each facility such as the technology of the facility, management plans and outlook for the facility, and the estimates for similar facilities for other utilities. For nuclear and hydro facilities that have operating licenses, the life span estimates are based on the license dates for each facility. *Id*. at 140. Witness Spanos further explained that since the last study was conducted, the life spans for several plant facilities for DEC have changed. He stated that Allen Units 4 and 5, Cliffside Unit 5, and Marshall Units 1 and 2 have life spans that are planned to be shorter than currently approved. *Id*. He noted, however, given that the depreciation rates are developed at the location level for Allen and Marshall, the individual life span dates are not presented in the results section of the Depreciation Study. Witness Spanos stated that he believes the revisions for the Allen, Cliffside, and Marshall units to be appropriate.

Witness Spanos additionally testified regarding DEC's replacement of its legacy electric meters. He stated that DEC has a program to replace its existing legacy electric meters with new technology meters. This replacement project is planned to be completed by the end of 2019. In accordance with the Commission's June 22, 2018 order in Sub 1146 (2018 DEC Rate Order), the net book value ($154 million) of the legacy meters will be amortized over 15 years.

Witness Spanos also testified regarding net salvage. Tr. vol. 12, 142-44. He testified that net salvage is a component of the service value of capital assets that is recovered through depreciation rates. The service value of an asset is its original cost less its net salvage. Net Salvage is the salvage value received for the asset upon retirement less the cost to retire the asset. When the cost to retire exceeds the salvage value, the result is negative net salvage. Witness Spanos testified that the net salvage percentages estimated in the Depreciation Study were based on informed judgment that incorporated factors such as the statistical analyses of historical net salvage data, information provided by the Company's operating personnel, general knowledge and experience of industry practices, and trends in the industry in general. The statistical net salvage analyses incorporate the Company's actual historical data for the period 2003 through 2018 and considers the cost of removal and gross salvage ratios to the associated retirements during the 16-year period. Trends of these data are also measured based on three-year moving averages and the most recent five-year indications.

Another topic discussed by witness Spanos was that of dismantlement or decommissioning costs. *Id*. at 144-45. Witness Spanos stated that he included a dismantlement or decommissioning component in the net salvage percentage for steam, hydro, and other production facilities. Witness Spanos explained that the dismantlement component is part of the overall net salvage for each location within the production assets. Based on studies for other utilities and the cost estimates of DEC, it was determined that the dismantlement or decommissioning costs for steam and other production facilities is best calculated by dividing the dismantlement cost by the surviving plant value at final retirement. These amounts at a location basis are added to the interim net salvage percentage of the assets anticipated to be retired on an interim basis to produce the weighted net salvage percentage for each location. Witness Spanos pointed out that the decommissioning cost estimates are based on the decommissioning studies of each generating site performed by Burns and McDonnell. Witness Spanos noted that these costs tend to increase over time and that for this reason, to allow DEC to recover the full decommissioning costs for each site, he believes these costs need to be escalated to the time of retirement. He included calculations of these escalated costs in the deprecation study.

Public Staff Direct Testimony

Witness McCullar testified that DEC was proposing an increase of $108.5 million in annual depreciation accrual. Tr. vol. 16, 595. She summarized the Public Staff's adjustments to reduce DEC's requested depreciation by $48.5 million, which is an increase of $60 million to depreciation accrual compared to the depreciation rates that were approved in the DEC 2018 Rate Order. She noted that the Public Staff is proposing changes to DEC's requested depreciation rates in the following functional categories: (1) Steam Production Plant (DEC is proposing 4.40% and Public Staff is proposing 3.90%); (2) Hydraulic Production Plant (DEC is proposing 2.00% and the Public Staff is proposing 1.99%); (3) Other Production Plant (DEC is proposing 3.21% and the Public Staff is proposing 3.12%); and (4) Distribution Plant (DEC is proposing 2.28% and the Public Staff is proposing 2.24%). She noted that total depreciable plant as proposed by DEC is 3.12% and 2.99% as recommended by the Public Staff. *Id*. at 596.

Witness McCullar specifically addressed the following additional issues in her testimony.

Contingency

Witness McCullar testified that DEC was again including a 20% contingency for future "unknowns." She proposed to eliminate the 20% contingency for future "unknowns" and noted that in the 2018 DEC Rate Order the Commission ordered that a 10% contingency factor be used. *Id*. at 603-04.

Terminal Net Salvage

Witness McCullar noted that in its 2018 DEC Rate Order the Commission found that DEC's proposal to escalate estimated future terminal net salvage costs to the assumed year of final retirement was reasonable and that the Public Staff was not recommending a change to DEC's proposed escalation of the estimated future net salvage costs in this proceeding. She explained that DEC was inflating the estimated future terminal salvage costs to the year of final retirement and that the future terminal net salvage costs are estimated in DEC's 2016 Decommissioning Study provided in Sub 1146. She further noted that the 2016 Decommissioning Study provides the estimated future terminal net salvage costs in year-2016 dollars. *Id*. at 606. Witness McCullar testified that in the 2018 Depreciation Study, these estimated future terminal net salvage costs are escalated to the year of the assumed retirement of the production plant, and that DEC proposes to collect a portion of these future inflated estimated costs from the current ratepayers in today's more valuable dollars (meaning with inflation the retirement-year dollars will have a lower purchasing power than today's nominal dollar). She further explained that it is these escalated retirement-year dollars that DEC is proposing to include in the calculation of rates to be charged to ratepayers. Witness McCullar stated that the concern is not that retirement-year dollars are worth less than current-year dollars. Rather, determining the cost of removal in retirement-year dollars and then collecting the inflated costs from current customers in more valuable current dollars is unreasonable since it imposes on today's ratepayers too much of the risk associated with a significantly long period of estimated future inflation. *Id*. at 607.

Public Staff witness McCullar testified that inflating the DEC estimated terminal net salvage cost to year 2023 would be a reasonable approach as an escalation year for estimated terminal net salvage costs. *Id*. at 610. Witness McCullar testified that five years is generally consistent with the period of time before the next rate case. The depreciation rates approved in this proceeding are expected to go into effect in 2018 — the year 2023 would be five years later — by which time depreciation rates would have been reviewed in a new base rate case. Therefore, her recommendation in this case is to inflate the terminal net salvage costs to the level of the dollars collected from the ratepayers for the time period the rates set in this proceeding are expected to be effective. This reduces the risk placed on today's ratepayers without exposing the Company to a risk that it will not be able to collect its actual net salvage costs over the long-term.

Interim Net Salvage

Witness McCullar testified that in the 2018 DEC Rate Order the Commission found that the interim net salvage percentages could be re-examined for accounts 342, 343, 344, 345, and 346 in a future rate case proceeding. *Id*. at 612-13. Witness McCullar testified that for interim net salvage costs, DEC is proposing a -5% interim net salvage percentage. Witness McCullar testified that for the last 3 years DEC has shown a positive net salvage, meaning that DEC has booked gross salvage amounts that have more than covered the incurred cost of removal costs. Therefore, witness McCullar proposed a 0% interim net salvage amount because DEC has not incurred interim net removal costs. *Id*. at 614. She noted, however, that 0% interim net salvage includes only the net salvage costs of retirements that occur prior to the final decommissioning of the plants — not the final decommissioning costs.

Mass Property Future Net Salvage

Witness McCullar testified that she had reviewed the reasonableness of DEC's proposed future net salvage for a mass property account and she was recommending -10% for Account 366, Underground Conduit, which is different than DEC's proposed -15% for this account. Witness McCullar noted that salvage ratios are a function of inflation and that the calculation of the historic net salvage ratio includes the impact of high historic inflation rates since the net salvage amount in the numerator is in current dollars and the cost of the plant (which may have been installed decades before) in the denominator is in historic dollars. *Id*. at 617. In other words, due to inflation the amounts in the numerator and denominator of the net salvage ratio are at different price levels. Witness McCullar testified that her proposed future net salvage accrual amounts consider DEC's historic practices and the impact of inflation, and builds a reserve for reasonable estimated future net removal costs associated with future retirements based on the type of investments in the account and her previous experience. *Id*. at 624.

DEC Rebuttal Testimony

Witness Spanos testified that witness McCullar's recommendations for net salvage are not established in a manner that will allow DEC to fully recover its future net salvage amounts. Tr. vol 22, 178. Witness Spanos testified that net salvage is estimated as the cost to retire an asset, net of any gross salvage, at the time the asset is expected to be retired. Net salvage is not estimated as today's cost to retire an asset. He stated that the reason for this is that if today's costs were estimated, then the application of straight-line depreciation would typically fail to recover the full cost to retire the asset because costs tend to increase over time. Witness Spano noted that the Commission ruled on this issue in the 2018 DEC Rate Order and found that full future net salvage costs should be included in rates and that estimating net salvage as the future costs to retire an asset is consistent with authoritative texts and depreciation practices. Witness Spanos further testified that witness McCullar's actual proposed depreciation rates incorporate the escalation concept consistent with the Commission's 2018 DEC Rate Order and that she makes one proposal for net salvage for distribution plant that is not consistent with that order. *Id*. at 181. Witness Spanos stated that witness McCullar proposed a less negative net salvage estimate for Account 366, Underground Conduit. He stated that while overall her proposal for this account does not have as significant an impact as her proposals for other accounts, she does not provide any statistical basis for her proposal other than to compare her results to the Company's recently recorded costs. Additionally, he noted that witness McCullar supported her proposal by arguing against including future inflation in net salvage estimates. Witness Spanos further testified that witness McCullar provided four cases where other state commissions removed the escalation of estimated future terminal net salvage costs. Witness Spanos refuted this by noting that one of these cases was a settlement, two are more than a decade old, and since those cases a number of power plants have been retired or decommissioned, many before they were fully depreciated and without full recovery of terminal net salvage. *Id*. at 185. Witness Spanos further refuted the testimony of witness McCullar by quoting the Commission's 2018 DEC Rate Order:

> The fact is the vast majority of jurisdictions use a method for net salvage in which future net salvage is estimated at its future cost and recovered through straight-line depreciation (also known as the traditional method). Approximately 46 out of 50 jurisdictions recover future costs using the straight-line depreciation method.

Id. at 186 (quoting 2018 DEC Rate Order at 175). Witness Spanos testified that witness McCullar only cites to a handful of cases to support her claim and that the vast majority of jurisdictions use the Company's approach to net salvage.

DEC witness Spanos also discussed coal ash closure costs. Witness Spanos testified that net salvage costs were included in the depreciation studies he performed for DEC as of 2003, 2007, and 2011 for most production plant accounts. *Id*. at 206. He stated that the issue is not that the Company has not included net salvage in its depreciation rates, but rather that the information DEC has today shows that the costs will be higher than anticipated. He stated that in addition to the background discussed above, the higher costs are function of the challenge in estimating future costs, which the Commission has recognized in noting that even though DEP included coal ash costs in its decommissioning studies, these estimates were too low compared to actual costs. Witness Spanos additionally stated that the prior DEC depreciation studies included terminal net salvage. *Id*. However, the terminal net salvage costs were not based on a decommissioning study as was the case in the last two depreciation studies (i.e., Sub 1146 and the instant case). *Id*. Due to factors such as the uncertainty of decommissioning costs, the tasks involved in decommissioning, and the timing of these costs the Company did not have similar decommissioning studies performed for the 2011 depreciation study and earlier studies. Instead, the estimates in those studies were based on the analysis of historical net salvage and retirements for production plant accounts. Because these estimates were implied to the entire account (rather than just the portion to be retired as interim retirements), they implicitly included a terminal net salvage component. Thus, although the specific cost elements were not defined, DEC has been recovering terminal net salvage costs since at least 2003. Witness Spanos noted that in Sub 1146 the specific decommissioning costs were more certain and therefore could be included at a greater level of detail.

Witness Spanos additionally testified that in the deprecation study he recommended an interim net salvage percentage of -6% for other production accounts, except for rotable parts at combined cycle plants. Witness Spanos noted that in the Commission's 2018 DEC Rate Order the Commission adopted an estimate of 0% for these accounts. He stated that since that time the data has changed and indicates a negative net salvage estimate. *Id*. at 194.

Discussion

Contingency Factor

Public Staff witness McCullar recommended that the currently approved 10% contingency for future "unknowns" included in DEC's estimate of future terminal net salvage costs continue to be used as opposed to the 20% proposed by the Company. Tr. vol. 16, 603. Witness McCullar noted that in the 2018 DEC Rate Order the Commission approved the use of a 10% contingency factor instead of the 20% contingency factor requested by DEC and included in the DEC Decommissioning Cost Estimate Study filed as Doss Exhibit 4 in that docket. She noted that in 2018 DEC Rate Order the Commission stated:

> The Commission is confident that a 10% contingency factor, while less than DEC's requested factor of 20%, should protect the Company from additional costs it will incur but cannot specify at the present date. The Commission also finds that a 10% contingency factor properly reflects the inclusion of items that should push unknown costs downward (i.e., increase in scrap prices, etc.) thereby protecting the ratepayers as well. Based on the foregoing, the Commission concludes that including a contingency factor of 10% should be utilized by the Company.

Id. at 603 (quoting 2018 DEC Rate Order at 172-73). Witness McCullar noted that DEC's proposed future terminal net salvage costs are again supported by the same DEC Decommissioning Cost Estimate Study reviewed in the 2018 DEC Rate Order.

DEC witness Spanos disagreed with witness McCullar's proposal to continue to use the 10% contingency previously approved by the Commission, stating that DEC has learned over the two years since the last Decommissioning Study was performed that the contingency estimates were understated. Tr. vol. 22, 259. He did not, however, provide any specific breakdown of costs to support the statement, other than to indicate that it was supported by experience from other industry participants and because more facilities have been decommissioned in recent years. *Id.*

The Commission agrees with DEC that inclusion of a contingency is often a standard industry practice to cover potential unknown costs that may or may not occur. However, the Commission agrees with the Public Staff that DEC has presented no new information or data supporting the need for a contingency percentage greater than the 10% contingency most recently approved by the Commission in the 2018 DEC Rate Order. As quoted above, in that proceeding the Commission expressed some concern regarding the accuracy of the decommissioning study, finding that DEC failed to consider certain factors, but concluded that a 10% contingency was fair to all parties.

The Commission acknowledges witness Spanos's experience and expertise, yet it notes that the contingency percentage utilized in the Depreciation Study and recommended in his testimony is based on the same Decommissioning Study used in the 2018 DEC Rate Order. In addition, witness Spanos does not provide any new data or information to support his claims regarding recent industry experience supporting an increased contingency percentage. This unsupported position would inappropriately shift a greater portion of the risk of future unknown, unidentified costs on current ratepayers.

The Commission finds that the increased contingency proposed by DEC in this proceeding is not supported by substantial evidence and therefore concludes that it is reasonable and appropriate for DEC to continue to use a contingency factor of 10% for net terminal salvage.

Other Production Interim Net Salvage

DEC witness Spanos testified that he recommended an interim net salvage percent of -6% for Other Production accounts, except for rotable parts at combined cycle plants. Tr. vol. 22, 193. He recognized that the Commission adopted an estimate of 0% for these accounts in Sub 1146 but stated that data over the past two years supports a negative net salvage estimate for each of these accounts. *Id.* Witness Spanos contended that the higher gross salvage numbers in DEC's previous depreciation study were related to the rotable parts of combined cycle facilities that are regularly refurbished and typically experience positive net salvage. *Id.* at 195. He noted that since the previous study, DEC has begun to account for rotable parts in a separate sub-account, resulting in the non-rotable parts accounts experiencing negative net salvage. *Id.* at 196.

Public Staff witness McCullar recommended an adjustment to the interim net salvage percentages of -5% proposed by DEC for Other Production Accounts 342, 343, 344, 345, and 346. Tr. vol. 16, 613. Witness McCullar pointed out that the historical analyses for these accounts show that, on average, the net salvage has been a positive $6,404,164 per year for the last three years and a positive $7,593,793 per year for the last five years. She explained that these positive net salvage amounts indicated that DEC's booked gross salvage exceeded the Company's incurred costs of removal and thus, DEC did not need to collect interim removal costs for these accounts. Therefore, witness McCullar proposed the continued use of a 0% interim net salvage, consistent with the Commission's finding in Sub 1146 and based on DEC's actual experience since that time. She noted that the 0% interim net salvage would not include the final decommissioning costs. *Id.*

Public Staff witness McCullar testified that in addition to relying on historic net salvage ratios, which are influenced by historic inflation levels, she also reviewed future net salvage costs included in DEC's proposed depreciation accrual and the actual net salvage costs incurred by DEC on average over the recent five-year period. Tr. vol. 16, 22. Witness McCullar noted cases in several jurisdictions that have adopted future net salvage percentages that recognized the inflated dollars included in the historic net salvage ratio and adopted future percentages that recognized the time value of cost of removal due to inflation. *Id.* at 619-21. Table 3 included in Witness McCullar's testimony provided a comparison of the actual net salvage costs incurred by DEC on average over the recent five-year period to future net salvage costs included in DEC's and the Public Staff's proposed depreciation accruals. Witness McCullar testified that her analysis provides a "reasonableness check" of the proposed future net salvage percentages, and that her "proposed future net salvage accrual amounts consider DEC's historic practices, the impact of inflation, and builds a reserve for reasonable estimated future net removal costs associated with future retirements, based on the type of investments in the account, and my previous experience." *Id.* at 624. As a result of her analysis, for Account 366, Underground Conduit, Witness McCullar recommended a future net salvage percent of -10%, which differs from DEC's proposed -15%. *Id.* at 615. Witness McCullar noted that even under her recommendation, the annual accrual for Account 366, Underground Conduit net salvage would still be $231,716, which is about 14.3 times the average annual amount DEC actually incurred. She further testified that her recommendation provides recovery of the expected cost of removal in the near future and builds the reserve for the future cost of removal associated with future retirements. *Id.* at 625.

DEC witness Spanos in rebuttal stated that the existence of a small number of instances where different approaches were used does not indicate that DEC's approach is consistent with the method used in the vast majority of jurisdictions. Tr. vol. 22, 184. He also testified that he did not believe that witness McCullar's analysis provides a reasonable basis to estimate future net salvage because it is based on the premise that depreciation accruals for net salvage should be similar to, if not the same as, the net salvage occurred each year. He stated that the goal of depreciation is to recover capital costs, including net salvage, over the service life of the assets and that there is not necessarily alignment between depreciation accruals for net salvage and incurred net salvage. Lastly, he noted that expressing historical net salvage as a percentage of historical retirements as he proposes properly recognizes the relationship between net salvage and retirements. *Id.* at 191-92.

On cross-examination, DEC witness Spanos testified that because the net salvage percent should reflect what is expected to happen going forward, sole focus on historical analysis is not sufficient. *Id.* at 262. He noted that with regard to Account 366, however, based on informed judgment, relying on historic salvage over a longer period of time is more representative than the most recent five-year period of time. *Id.* at 264. Witness Spanos acknowledged that the Kansas State Corporation Commission (KSCC) in a recent decision found that a net salvage analysis that estimates appropriate levels of future net salvage and does not rely solely on historic expense levels is appropriate. *Id.* at 265-67 (citing Order on Atmos Energy Corporation's Application for a Rate Increase; No. 19-ATMG-525-RTS, at ¶¶ 52-54 (K.S.C.C. Feb. 24, 2020). He also acknowledged that the KSCC found that the approach recommended by the KSCC Staff in that proceeding, which in part considered the level of net salvage in recent years, not as a percentage of retirements, best balanced the interests of the utility's current and future ratepayers. *Id.*

Based on the above evidence, the Commission finds that the Public Staff's proposal of a future net salvage percent of -10% for Account 366, Underground Conduit, is reasonable since it is within the range of the historic net salvage percentage, Spanos Ex. 1 at 342, and builds a reserve for future removal costs, tr. vol. 16, 623-24, while balancing the interests of current versus future ratepayers.

Terminal Net Salvage

Establishing the service value of the Company's assets requires determining the net salvage costs of those assets that will be incurred in the future. As DEC witness Spanos explained, using the straight-line method of depreciation, these costs are recovered ratably, or in equal amounts, each year over the life of the Company's plant. Tr. vol. 12, 146. This approach is consistent with the USOA, which specifies that the cost of removal is the actual amount paid at the time the transaction takes place. Tr. vol. 22, 187. As such, including the future cost of net salvage for plant accounts is consistent with established depreciation concepts. *See* 2018 DEC Rate Order at 173. In developing decommissioning cost estimates it is necessary to escalate the estimates to the time period in which the cost is expected to be incurred. *Id.* at 173.

Witness McCullar testified that net salvage estimates for decommissioning the Company's power plants are escalated to the date of final retirement, consistent with the 2018 DEC Rate Order. Tr. vol. 16, 605. Confusingly, however, witness McCullar proceeded to discuss the concept of escalation and appeared to advocate instead for only escalating costs to the year 2023. Witness McCullar testified that she selected 2023 because it "would inflate the terminal net salvage costs to the level of the dollars collected from the ratepayers for the time period the rates set in this proceeding are expected to be reasonable." *Id.* at 610. Witness McCullar contended that it would be unreasonable to collect inflated costs of removal in current dollars because it imposes too much risk on ratepayers due to the significant period of time over which the inflation is estimated. *Id.* at 607. Additionally, Witness McCullar noted that four other jurisdictions have removed the escalation of estimated future terminal net salvage costs. *Id.* at 611-12.

As explained by witness Spanos, the Commission reviewed this concept in Sub 1146 and determined that "the escalation of terminal net salvage cost and the use of the straight-line method of depreciation in determining escalation as performed in the DEC Decommissioning Study is just and reasonable, appropriate for use in this case, and is adopted." Tr. vol. 22, 180 (quoting 2018 DEC Rate Order at 175). The Commission also concluded that estimating net salvage as the future cost to retire an asset is consistent with sound depreciation practices and authoritative texts. *Id*. (quoting 2018 DEC Rate Order at 174). Specifically, the Commission cited the National Association of Regulatory Utility Commissioners (NARUC) Public Utility Depreciation Practices for the principle that "[n]et salvage is the difference between gross salvage that will be realized when the asset is disposed of and the costs of retiring it." *Id*. (quoting 2018 DEC Rate Order at 174). The Commission also cited Wolf and Fitch, another highly regarded authoritative depreciation text, for the position that inflation is appropriately a part of the future cost of net salvage. *Id*. at 189-90 (quoting 2018 DEC Rate Order at 174). In his testimony, Witness Spanos provided the following passage from Wolf and Fitch:

> The matching principle specifies that all cost incurred to produce a service should be matched against the revenue produced. Estimated future costs of retiring an asset currently in service must be accrued and allocated as part of the current expenses.

Id. at 189. Wolf and Fitch also make clear that inflation is part of the future cost of net salvage. Witness Spanos pointed out that Wolf and Fitch state the following:

> Negative salvage is a common occurrence. With inflation, the cost of retiring long-lived property, such as a water main, may exceed the original installed cost.

Id. Additionally, with respect to intergenerational equity, Witness Spanos noted that Wolf and Fitch state:

> The accounting treatment of these future costs is clear. They are part of the current cost of using the asset and must be matched against revenue. While the current consumers would say they should not pay for future costs, it would be unfair to the future users if these costs were postponed.

Id. at 189-90. Finally, Wolf and Fitch also argue against a present value or current value concept. Witness Spanos provided the following excerpt from Wolf and Fitch:

> Some say that although the current consumers should pay for the future costs, the future value of the payments, calculated at some reasonable interest rate, should equal the retirement cost. Studies show that the salvage is often "more negative" than forecasters had predicted.

Id. at 190.

Accordingly, witness Spanos contended that Commission precedent, authoritative texts, and sound depreciation practices all support escalating terminal net salvage costs to the date the costs are expected to be incurred rather than some artificially foreshortened date and that while witness McCullar claimed that four other jurisdictions removed the escalation of estimated future terminal net salvage costs, none of the cases witness McCullar cited change the fact that the Commission has already decided this issue in Sub 1146. *Id.* at 185. Further, witness Spanos explained that of the four cases witness McCullar cited, one is a settlement agreement and two are from more than a decade ago. *Id.* at 185. Since that time, a number of power plants have been retired and decommissioned — many prior to being fully depreciated and without full recovery of terminal net salvage. Accordingly, the cases witness McCullar cites are not particularly relevant to the instant proceeding. Moreover, in Sub 1146 the Commission found that the Company's approach to net salvage is used by the vast majority of regulatory jurisdictions. *Id.* at 185 (quoting 2018 DEC Rate Order at 175). Specifically, the Commission stated:

> The fact is the vast majority of jurisdictions use a method for net salvage in which future net salvage is estimated at its future cost and recovered through straight-line depreciation (also known as the traditional method). Approximately 46 out of 50 jurisdictions recover future costs using the straight-line depreciation method.

Id. at 186 (quoting 2018 DEC Rate Order at 175).

North Carolina is one of those majority jurisdictions that uses the traditional method. The cases cited by witness McCullar are in the minority and for that reason should not be afforded any weight in this proceeding. *Id*. at 186. Finally, the Commission previously found witness McCullar's approach to estimating terminal net salvage to be deficient. *Id.* at 182. In the 2018 DEC Rate Order, witness McCullar challenged the inclusion of the full future net salvage cost in depreciation and instead proposed to include only estimates of net salvage costs at current cost levels. *Id.* at 180. As witness Spanos explained above, the Commission already reviewed this concept in Sub 1146 and did not find witness McCullar's arguments persuasive. *Id.* at 181. In the 2018 DEC Rate Order, the Commission stated the following:

> Witness McCullar's approach is not supported by sound depreciation methods and would likely result in the under recovery of net salvage costs over the life of the asset. To that end, other state utility commissions have rejected witness McCullar's alternative approach as unsupported. For example, in a recent case before the Washington Utilities and Transportation Commission (WTC), witness McCullar advanced similar arguments against the escalation of terminal net salvage costs along with other recommendation related to depreciation. In rejecting the recommendation, the WTC noted that Public Counsel and witness McCullar provided no response to the critique that witness McCullar's approaches were not supported by authoritative accounting literature. The WTC found witness McCullar's net salvage proposal "[v]ague in its methodology, not supported by authoritative accounting literature, and supported by unwarranted assumptions."

Id. at 182 (quoting 2018 DEC Rate Order at 175).

Considering all the evidence, the Commission finds and concludes that the escalation of terminal net salvage cost and the use of the straight-line method of depreciation in determining escalation as performed in the Decommissioning Study is just and reasonable, appropriate for use in this case, and is adopted.

Mass Property Future Net Salvage

Net salvage estimates are expressed as a percentage of the original cost retired. *Id*. The method for determining the estimated net salvage percent depends on the type of property. *Id.* at 183. For power plants, the estimate is typically based on a decommissioning study, with additional net salvage incorporated for interim retirements. For mass property accounts such as those for transmission and distribution plant, net salvage estimates are based in part on statistical analyses of historical net salvage data. *Id.* In this case, the statistical net salvage analyses incorporate the Company's actual historical data from 2003 through 2018 and considers the cost of removal and gross salvage ratios to the associated retirements during the 16-year period. *Id*. at 143.

Witness Spanos in his Depreciation Study recommends a net salvage percentage of -15% for Account 366, Underground Conduit. Witness McCullar recommends a future net salvage percent of -10% for Account 366, Underground Conduit. Tr. vol. 16, 615. Witness McCullar expressed concern with the Company's historic net salvage ratios calculated in the Depreciation Study. Specifically, witness McCullar took issue with using a net salvage ratio that includes inflated dollars in the numerator and historic dollars in the denominator. Witness McCullar explained that due to inflation, the amounts in the numerator and denominator of the net salvage ratio are at different price levels. *Id.* at 617-18. Witness McCullar noted that five other jurisdictions have adopted future net salvage percentages that recognized the inflated dollars included in the historic net salvage ratio and adopted future net salvage percentages that recognize the time value of cost of removal due to inflation. *Id.* at 618-21.

In response, witness Spanos testified that witness McCullar's proposal is not consistent with the Commission's decision in Sub 1146 and is unsupported by the record. Tr. vol. 22, 181-82. Witness McCullar supports her treatment of Account 366 by arguing against including future inflation in net salvage estimates. As witness Spanos previously testified, the Commission has already decided against witness McCullar's position on this concept and found that the Company's approach was widely supported. Overall, while witness McCullar's proposal for Account 366 does not have as significant an impact as her proposals for other accounts, she does not provide any statistical basis for her proposal. *Id.* The only analytical method witness McCullar provides in support of her proposal is a comparison of the net salvage costs included in the proposed depreciation rates to the amount of net salvage DEC has incurred, on average, over the past five years. This type of analysis performed by witness McCullar does not provide a reasonable basis to estimate net salvage. Additionally, NARUC and Wolf and Fitch do not support witness McCullar's approach for mass property accounts. *Id.* at 191-92. In fact, the Company is unaware of any authoritative texts that support witness McCullar's analysis. *Id.* Witness Spanos also notes that witness McCullar adopted this backward looking "recent history" approach for calculating net salvage only with regard to Account 366 and not to other property accounts. Tr. vol. 23, 70. At the hearing in this matter, witness Spanos testified extensively that relying solely on recent historical data, as witness McCullar does for her mass property Account 366 recommendation, is inappropriate. Tr. vol. 22, 261-63. He testified to the following:

> So in each category depending on the assets and on what you learned from the Company and doing studies within the industry, you're able to come up with the most appropriate net salvage percentage that would incorporate not only the overall but also the most recent as well as what's expected in the future. Because the net salvage percent that you determine is what we expect to happen going forward, so we can't just focus on the past.

Id. at 262.

In this regard, witness Spanos also testified that conduit is not typically an asset that is removed upon retirement and that this further supports a more negative net salvage value as proposed by the Company. *Id.* at 264. Witness Spanos was also asked on cross-examination about the net salvage calculation in an Atmos Energy rate proceeding in Kansas in which witness McCullar testified. Public Staff Spanos Cross-Examination Ex. 1. This testimony did not undermine witness Spanos' position on net salvage, however, because it was clear from the face of the order in that proceeding that the KSCC explicitly rejected a proposed negative salvage calculation based on a "recent history" approach similar to that offered by witness McCullar in this case. *Id.* at ¶ 54.

Considering all of the evidence, the Commission finds and concludes that the Company's proposed future net salvage for mass property Account 366, Underground Conduit, is just and reasonable, appropriate for use in this case, and is adopted.

Fifteen-Year Service Life for AMI Meters

DEC requested a 15-year depreciation life for AMI meters in this proceeding. As explained by witness Spanos, a 15-S2.5 survivor curve was recommended by DEC for AMI meters. Tr. vol. 22, 197. Spanos testified that DEC's position is consistent with the manufacturer's recommendation for the physical life of the AMI meters and accounted for alternative reasons for retirement such as damage or obsolescence. *Id.*

Public Staff witness McCullar recommended a 17-year service life for AMI meters. Witness McCullar testified that a 17-year life is in the middle of the manufacturer's range, is a reasonable estimate based on the manufacturer's expected life of the AMI meters, and is fair to the Company and the ratepayer. Tr. vol. 16, 615.

In response witness Spanos pointed out that the Commission approved the 15-year service life for AMI meters in the 2018 DEC Rate Order. DEC used a 15-year average service life in its previous depreciation study in Sub 1146. The 2018 DEC Rate Order adopted the depreciation rates proposed by DEC, except for certain depreciation rates discussed in the decision. As witness Spanos explained, because the 15-year average service life was not specifically identified and modified in the 2018 DEC Rate

Order, the 15-year average service life was adopted by the Commission. Tr. vol. 22, 196-97. Moreover, DEC's cost-benefit analysis for AMI meters was based on a 15-year average service life and the Commission had specifically requested that such analysis include the "cost of replacing AMI meters at the end of their 15-year useful life." *Id*. at 197 (quoting 2018 DEC Rate Order at 117).

On cross-examination by Public Staff counsel, witness Spanos further bolstered the reasonableness of a 15-year average service life for AMI meters by indicating that this period is the most common service life used for this type of asset in the industry and based on the type of asset, this survivor curve most appropriately reflects the manufacturer's expectations. Tr. vol. 12, 174.

Witness McCullar provided no new evidence in the instant case that supports changing the 15-year average service life approved by the Commission. Witness Spanos noted that witness McCullar's arguments are almost identical to those she presented in Sub 1146, which were not persuasive to the Commission. Tr. vol. 22, 197-98. Additionally, witness McCullar simply took the mid-range of the manufacturer's life without considering issues like technological obsolescence. In that regard, witness McCullar made no attempt to distinguish the type of asset, which is a critical consideration when there is limited historical experience.

Based upon all the evidence, the Commission finds and concludes that the Company's request to establish a 15-year average service life for AMI meters is just and reasonable and appropriate for use in this case.

Conclusions

Based on the foregoing conclusions regarding the Depreciation Study filed by DEC in this proceeding as Spanos Direct Exhibit 1, the Commission finds that DEC shall: (1) continue to use a 10% contingency for future "unknowns" in the estimate of future terminal net salvage costs; (2) use an interim net salvage percentage of zero for Accounts 342, 343, 344, 345, and 346, (3) use the straight-line method of depreciation in determining escalation as performed in the Decommissioning Study; (4) use its proposed future net salvage for mass property Account 366, Underground Conduit; and (5) use an average service life of 15 years for new AMI meters being deployed. The Commission further concludes that except where specifically addressed in this Order, the remaining depreciation rates as proposed by DEC in this case shall be used in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 14–15

Early Retirement of Coal Plants

The evidence supporting these findings of fact is found in the verified Application and Form E-1, the testimony and exhibits of DEC witnesses De May, Spanos, and McManeus and Public Staff witnesses Metz and Boswell, and the entire record in this proceeding.

Summary of the Evidence

Within the context of its new Depreciation Study, DEC altered the life spans of Allen Units 4 and 5 and Cliffside Unit 5 to be shorter than what is currently approved. DEC witness De May explained that “[a]s part of our strategy to reduce our reliance on coal, we have taken a fresh look at the viability of several of our coal-fired plants and have concluded that making shifts in the expected remaining depreciable lives of some of our coal-fired assets is a reasonable action to take now, while we continue to monitor the changing industry landscape and impacts of markets forces.” Tr. vol. 11, 859.

DEC witness Spanos testified that DEC intends to retire Allen Units 4 and 5 in 2024 and Cliffside Unit 5 in 2026. Tr. vol. 22, 198. He testified that the new life span for Allen Units 4 and 5 is 67 years and the new life span for Cliffside Unit 5 is 54 years. Tr. vol. 12, 141. Witness Spanos incorporated these shortened life spans into the Depreciation Study and recommended depreciation rates using these retirement dates. Tr. vol. 22, 198. DEC witness Spanos stated that the revised life spans are reasonable because in recent years original life spans for steam production facilities have been shortened due to unit efficiencies and environmental regulations. Tr. vol. 12, 141.

Public Staff witness Metz testified that these retirement dates are earlier than shown in DEC’s 2018 IRP and 2019 Update filed on September 3, 2019, in Docket No. E-100, Sub 157. Witness Metz further testified he believes that the Company’s IRP proceeding is the appropriate venue for a thorough review of early, or any, generation retirements. Tr. vol. 16, 671-73.

Public Staff witness Boswell noted the planned retirement dates of Allen Units 4 and 5 and Cliffside Unit 5, and she recommended a five-year depreciation rate for the plants. Witness Boswell, however, testified that she recommended that Public Staff witness McCullar restore the depreciation rate of these units to the depreciation rates approved in the Company’s last general rate case in Sub 1146. Tr. vol. 17, 245. Witness Boswell testified that her recommendations regarding the depreciation change were based on the following reasons: (1) although the Company has stated in its testimony that it intends to retire these plants, it has not presently done so; (2) the Public Staff has consistently recommended leaving the depreciation rates set at the original retirement date of the plant, and, at the date of actual physical retirement, any remaining net book value be placed in a regulatory asset account and amortized over an appropriate period, to be determined in a future general rate case; and (3) the Public Staff believes it is appropriate to continue this consistent treatment of retired plants. *Id.*

Company witness McManeus testified in her rebuttal testimony that the Company disagrees with the Public Staff’s adjustment. Company witness Spanos testified that as a matter of principle, the concept witness Boswell sets forth does not comport with the USOA or with generally accepted depreciation principles. Witness Spanos further stated that while the Public Staff may have taken this position in the past, it is inequitable by definition because the costs that would be placed in a regulatory asset account and amortized over a given period will be recovered after the facility is retired. He further stated that the Public Staff's proposal will, by design, result in intergenerational inequity. Tr. vol. 22, 200-01.

During cross-examination, witness Spanos accepted that under N.C.G.S. § 62-35 the Commission sets the rules for DEC's North Carolina retail accounting practices. Witness Spanos further agreed that Commission Rule R8-27 provides for the FERC USOA to be the default system of accounts for electric utilities that are regulated by the Commission. Tr. vol. 22, 282-83. Finally, witness Spanos testified that the Commission has historically provided for costs to be recovered from customers after assets have been retired. During cross-examination, witness Spanos was presented with two examples in which the depreciation expense of DEP's plants were recovered from ratepayers in the years after they were retired. Tr. vol. 22, 287-92; Public Staff Doss Spanos Rebuttal Cross-Examination Ex. 2.

Discussion and Conclusions

Based on the foregoing and the record, the Commission finds that it is appropriate to require DEC to continue to depreciate the Allen Units 4 and 5 and Cliffside Unit 5 generating plants based upon their remaining useful lives as approved in Sub 1146. In reaching this conclusion the Commission gives significant weight to Public Staff witnesses Boswell's and Metz's testimonies. The Commission agrees with witness Metz that the Company's IRP proceeding is the appropriate venue for a thorough review of early, or any, generation retirements. Moreover, the Company did not file the requested accelerated depreciation for the plants in either its 2018 IRP or the 2019 Update, the latter of which was filed one month prior to DEC's filing of the present rate case.

Witness Boswell testified that the Public Staff has consistently recommended leaving the depreciation rates set at the original retirement date of the plant. Further, she stated that at the date of actual physical retirement any remaining net book value should be placed in a regulatory asset account and amortized over an appropriate period to be determined in a future general rate case. The Commission determines that this methodology is supported by the examples that the Public Staff provided during cross-examination of Company witness Spanos. When presented with Public Staff Doss Spanos Rebuttal Cross-Examination Exhibit 2, witness Spanos affirmed that DEP used the same methodology as proposed by witness Boswell in this proceeding in its last rate case, Docket No. E-2, Sub 1142 (Sub 1142). Witness Spanos further confirmed this same treatment was approved by the Commission in Docket No. E-2, Sub 1023 for retirement of DEP's Cape Fear, Lee, Robinson, Weatherspoon, and Morehead City coal plants.

The Commission has strived consistently to balance allowing utilities the full recovery of early generating plant retirement costs while not unduly burdening ratepayers. In the present case the Company's proposed accelerated depreciation would unduly burden the ratepayers for the next several years as they would be paying more for electric service. On the other hand, DEC would be recovering the plants' costs more quickly than last supported by its IRP, which is where generation mix and service lives of DEC's assets are fully vetted. As DEC has not updated its IRP for the service life changes of the Allen Units 4 and 5 and Cliffside Unit 5 generating plants, the Commission and other parties have not had the chance to fully examine the issue within the context of an IRP. For these reasons, the Commission finds using the Company's approach at this time would yield an unbalanced disproportionate result.

Therefore, in light of the foregoing, the Commission finds that the depreciation for the Allen Units 4 and 5 and Cliffside Unit 5 generating plants should be based upon their remaining lives as presented in Sub 1146, and upon the actual retirement of each unit, the remaining net book value should be placed in a regulatory asset account to be amortized over an appropriate period which will be determined in a future rate case.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 16–18

Alleged Uneconomical Coal Plant Costs

The evidence supporting these findings of fact is found in the verified Application and Form E-1; the testimony and exhibits of DEC witness Immel, Public Staff witness Metz, NC WARN witness Powers, Sierra Club witness Wilson, and Tech Customers witness Strunk; and the entire record in this proceeding.

Summary of the Evidence

DEC Application and Direct Testimony

In its Application, DEC stated that since its previous rate case it has made capital investments in its coal fleet to meet environmental regulations to allow for the continued operation of active coal units, and to allow certain coal units to burn natural gas. The Company stated that by enabling natural gas co-firing (dual fuel optionality or DFO), it can increase fuel flexibility and further reduce carbon emissions across the Carolinas to benefit customers. Application at 4-5, 7.

Company witness Immel described the Company's Fossil/Hydro/Solar Operations (FHO) fleet and provided operational performance results for those assets during the test period. Tr. vol. 12, 53-54, 59-61. Witness Immel also addressed major FHO capital additions DEC has completed since the previous rate case. Witness Immel explained that the Company has made significant investments in the coal fleet to meet environmental regulations to allow for the continued operation of active plants. Witness Immel also discussed the DFO conversion projects at Cliffside Station and Belews Creek Unit 1, which he stated allow the Company to utilize the most cost-effective fuel and provide fuel flexibility. Witness Immel testified that the Company prudently incurred all of these costs. Furthermore, he stated that these investments are used and useful in providing electric service and benefit customers as they have enabled DEC to continue to provide safe, efficient, and reliable service at least reasonable cost and have reduced DEC's environmental footprint by adding state-of-the-art technology for reducing emissions and expanding the use of natural gas generation at a time when the natural gas market is providing low prices. *Id.* at 56-59.

Public Staff Direct Testimony

In his direct testimony Public Staff witness Metz discussed his review of DEC's capital additions to the FHO fleet. Witness Metz noted that his investigation included, in addition to reviewing the Company's testimony, an audit of specific expenditures, initial and follow-up discovery, teleconferences between and interviews with the Company and Public Staff, site visits, and review of the overall projects with Company management. Tr. vol. 16, 660-61. Witness Metz recommended an adjustment to remove the capital project costs related to the DFO conversion project at Belews Creek. Upon further review, witness Metz reversed that recommendation in his supplemental testimony. Based on the Company's prudence in capital investments in its FHO generation assets he recommended no disallowance. *Id.* at 661-64,680.

NC WARN Direct Testimony

NC WARN witness Powers recommended disallowance of the Company's costs for the DFO conversion projects. Witness Powers contended that the investments in these projects were not reasonable or prudent based on his assertion that DEC could have avoided them by relying on regional merchant combined cycle, hydroelectric plants, and the addition of battery storage at existing North Carolina solar facilities. *Id.* at 51-57. Witness Powers also stated that burning natural gas in steam boilers formerly fired on coal reduces the thermal efficiency of the combustion process and compared the production cost at coal-fired units to approximations of production cost at a combined cycle facility and hydroelectric unit. *Id*.

Sierra Club Direct Testimony

Sierra Club witness Wilson recommended disallowance of all of the Company's capital expenditures made during the time between the Sub 1146 case and the current case. Her recommendation is based on her contention that the net value of each of the coal units was negative for the 2016-2018 time period and that said costs should be disallowed until DEC provides evidence of an analysis demonstrating the value of the investment that was performed at the time the investment decision was made. Witness Wilson also claimed that the coal units only have positive net value in years with extreme weather, and she recommended that DEC consider operating these units seasonally and only during months of peak demand to minimize losses to ratepayers until the plant's retirement dates. Tr. vol. 18, 150, 156-62. Based on her projection of the future energy value of the DEC coal fleet and citing the Georgia Public Service Commission (GPSC) as having taken similar action, she recommended that the Commission cap future capital expenditures intended to prolong the lives of these units and require DEC to obtain Commission approval of any expenditure that exceeds the cap before it can be recovered from customers. *Id.* at 162-67. Witness Wilson acknowledged the advancement of the probable retirement dates of certain units based on the Company's updated depreciation study. *Id.* at 151). She stated that retirement of the entire coal fleet at once would likely lead to reliability issues in DEC's service territory. She suggested that the used and useful standard could be interpreted to mean that if there was a power plant construction project planned in a prudent manner that operates at costs significantly higher than the economic value of the output for reasons beyond the utility's control and ability to reasonably foresee, that plant may be found prudent and used, but not economically useful. *Id.* at 166-68.

Tech Customers Direct Testimony

Tech Customers witness Strunk recommended disallowance of the incremental capital expenditures at Allen Units 4 and 5 and Cliffside Unit 5 between the Sub 1146 case and this case absent further justification of these investments. Focusing on general coal trends and these units' capacity factors, he took issue with these investments in light of DEC's current proposal to accelerate the units' depreciable lives. Tr. vol. 16, 146-51. Witness Strunk also questioned the Company's prior decision not to retire these units early but did not independently assess the retrospective economics of potential retirement decisions. *Id.* at 151-55. Witness Strunk contended that a primary reason for DEC's previous decisions regarding these units was the risk to investors of early retirement, although he recognized the reasonableness of this consideration. *Id.* at 153-54, 156. Witness Strunk acknowledged that much of the Company's recent coal-related investments involved compliance with coal ash regulations but questioned whether earlier retirement of these units could have reduced the amount of these investments. He stated that he has not performed a detailed IRP-type analysis but suggested that DEC could replace a coal unit's energy and capacity with purchased power, surplus capacity, utility-scale renewables, and energy efficiency and demand response. *Id.* at 159-61.

DEC Rebuttal Testimony

With regard to witness Metz's recommended disallowance of the Belews Creek DFO project costs, DEC witness Immel explained that the project is used and useful as it was placed in service on January 10, 2020, and began serving electric power to customers at that time. Tr. vol. 12, 64-66.

Witness Immel also described the voluminous information that DEC provided through discovery in this case in addition to the evidence presented in his direct and rebuttal testimonies. *Id.* at 66, 68-70. Addressing arguments concerning the economic value of the coal fleet, he explained that such contentions fail to recognize the full picture of how DEC dispatches its coal fleet to maximize value for customers, and he noted that witness Wilson's study did not appear to account for the requirement of day-ahead planning reserves. Witness Immel acknowledged that the capacity factors of the coal fleet are declining but explained that DEC requires cycling resources, which operate at lower capacity factors, to provide reliable service to customers in periods of high demand. Witness Immel explained further that a coal unit will provide energy and capacity during the peak and that if a needed coal unit is not online, then the Company must start additional combustion turbines and/or purchase energy and capacity from the market, if capacity is available during such a time. *Id.* at 73-74.

Witness Immel also testified that witness Wilson's forward-looking analysis of the coal fleet is not a valid exercise for a general base rate case. Witness Immel noted that witness Wilson did not explain how her proposed cap on future coal fleet investments would be determined. He testified that these investments were not made to "prolong" the life of particular units but rather to maximize their remaining useful life. Witness Immel stated that the Company cannot recover such costs from customers unless and until the Commission permits it to do so. Finally, he clarified that estimates of future capital investments are not relevant to this proceeding. *Id.* at 75-76.

In response to witness Strunk, witness Immel testified that DEC studied the potential early retirement of Cliffside Unit 5 and Allen Station in 2016 and 2017, respectively, in order to make a timely decision regarding completion of upgrades at those units that were required by state and federal laws and regulations in order to maintain the units' environmental compliance and continue reliably serving customers. Witness Immel stated that given the knowledge the Company had at the time, the studies did not show a compelling economic case for early retirement versus making the required capital investments. Witness Immel concluded that DEC therefore made the prudent decision in both cases to invest in the projects. *Id.* at 70-71. Witness Immel stated that the suggestion that DEC's previous retirement decisions were based primarily on the risk to investors disregarded the many factors considered by the studies, including needed transmission upgrades, replacement power needs, and timing of environmental compliance. Witness Immel also explained that net book value is not part of the economic analysis of early retirement but rather an additional separate consideration, and that the Allen Station retirement study on its own did not support early retirement. *Id.* at 72, 104. Witness Immel noted that DEC's subsequent decision, with the benefit of new and updated information about costs and risks, to propose accelerated depreciation of Allen Units 4 and 5 and Cliffside Unit 5 indicates that the Company is making prudent decisions based on the information available at the time. *Id.* at 73.

In response to witness Powers, witness Immel testified that the DFO project costs were reasonably and prudently incurred. Witness Immel noted that DEC conducted multiple cost-benefit analyses of these projects, which indicated that they would provide the Company and its customers economic value in the form of optionality with fluctuating coal and natural gas commodity prices and resulting lower fuel costs for customers. Regarding efficiency, he explained that while thermal efficiency does decline with DFO, auxiliary load also decreases due to the elimination or reduction of the need for coal processing systems, ash systems, and wastewater treatment systems. Therefore, in response to questions from NC WARN's counsel, he testified that the overall efficiency of the generating unit is minimally impacted. *Id.* at 77-78, 84-85. Witness Immel also explained that the majority of the DFO investment at Cliffside Station was for Unit 6, which can run 100% on natural gas, and that the Company has already realized savings for customers from these projects. *Id.* at 87, 112. On redirect examination, he described the faster ramping capability these projects provide, which in addition to helping DEC follow load throughout the day, helps enable increasing levels of intermittent renewable generation as well as savings related to startup costs. *Id.* at 110-11.

Finally, in response to suggestions that the Company could provide reliable electric service through purchased power and renewable resources without the continued availability of its coal fleet, witness Immel testified that no witness offered a credible and specific explanation of how DEC could have replaced the reliable generation provided by

Belews Creek, Cliffside, or Allen with these resources. Witness Immel stated that neither witness Strunk nor witness Powers credibly challenged DEC's reasonable and prudent decisions to maintain operations at Allen Units 4 and 5 and Cliffside Unit 5 and to invest in the DFO projects. *Id.* at 78-79.

At the hearing in response to questioning by Sierra Club counsel, witness Immel explained that in studying the early retirement of Allen Station and Cliffside Unit 5 in 2016, DEC assumed natural gas fired generation would replace these units because recent IRP filings indicated that was the most economical dispatchable replacement resource. He noted the importance of the voltage support provided by Allen Station during the study timeframe. *Id*. at 92-93, 97-98. Witness Immel clarified that a significant portion of the coal fleet environmental investments would have been required regardless of whether the units were retired, and he testified that even if a variance of such requirements were obtained for Allen Station, the units would not have been able to retire early due to transmission concerns. *Id.* at 100-01. He further noted that witness Wilson's analysis did not consider the capacity value provided by the coal units, even if they are not running. *Id.* at 106-08, 118, 120.

With respect to witness Wilson's testimony regarding the profitability of the coal fleet during peak hours, witness Immel testified that in order to run units during peak hours DEC must maintain them so that they can be available when needed. *Id.* at 120. Addressing the changes in plans for the coal fleet from the time of the earlier retirement studies to this case and going forward, witness Immel stated that DEC continues to look for opportunities to retire coal plants in the most organized fashion with economic benefit to the customer while meeting the state's and the Company's own emissions goals. *Id.* at 121-22. During redirect examination, he testified that the most recent retirement plans for these units support DEC's request for accelerated depreciation of certain units in this case. Witness Immel also testified that no party presented any alternative that DEC could have chosen other than to make the investments in the coal fleet. *Id.* at 122-24.

In response to questions from counsel for the Company, Sierra Club witness Wilson agreed that as DEC transitions away from reliance on coal it must do so while continuing to meet its obligation to provide safe and reliable electric service to customers. Tr. vol. 18, 176. Witness Wilson acknowledged that her study of the economic value of the coal fleet did not analyze what DEC should have done with the information available to it at the time it incurred the costs to maintain these units, did not evaluate what replacement alternatives the Company should have chosen instead of making the investments, and did not identify any particular investment DEC should not have made. Witness Wilson testified that she was not aware of the North Carolina standard for challenging prudence that requires a party to identify specific instances of imprudence and provide a prudent alternative. *Id.* at 177-79. With regard to her testimony on the "used and useful" standard, she could not identify any state commission that had adopted her interpretation of that standard. *Id.* at 183.

Witness Wilson agreed that some of the coal fleet environmental investments were required whether or not the units continued to operate and that if additional environmental improvements had not been made, DEC would have had to shut the units down. Witness

Wilson testified that she did not analyze whether shutting the units down was a feasible path DEC could have chosen and still have been able to meet its service obligations. When asked to illustrate her testimony that retiring all of the units immediately would likely result in reliability issues, she stated that "the lights . . . could potentially go out," and she noted that retiring all of the coal units would not be sufficient to meet peak load plus a required reserve margin. *Id.* at 187-89.

Witness Wilson acknowledged that North Carolina uses a historical test year, updated through a certain time period, to examine reasonableness and prudency of costs. With regard to the case she cited in support for her future investment cap proposal, she agreed that the Sierra Club did not join the stipulation approved by the GPSC and that the nonsigning parties' recommendations in that case were specifically denied. *Id.* at 184-86.

Further, witness Wilson agreed that the results of the 2016 Allen Station retirement study indicated that DEC would have incurred greater costs by retiring the station early than by making the investments required to continue to run it but stated without further explanation that she objected to a number of the input assumptions made in the study. Witness Wilson stated that her analysis did not look at the need for replacement capacity for any of the coal units if they were shut down. She testified that she did not mention the Allen Station study in her testimony, analyze the data provided in the study, or use any of the information DEC provided through discovery to conduct a retirement study for any of the coal units. *Id.* at 197-200.

In response to questioning by Commissioner Hughes regarding how to reconcile her testimony that retirement of the entire coal fleet would lead to reliability issues with her recommendation to categorically exclude all costs of the coal fleet, witness Wilson clarified that her recommendation was to exclude the capital costs until the Company could provide economic analysis showing that the units were cost-effective for customers. *Id.* at 205.

Discussion and Conclusions

Based on the substantial evidence presented by DEC witness Immel, the Commission finds and concludes that the costs associated with the Company's investments in its coal fleet were reasonably and prudently incurred and should be recovered. The Commission further finds and concludes that Sierra Club's recommendation to limit the Company's future investments in its coal units should not be adopted. Finally, the Commission finds and concludes that the costs for the Belews Creek Unit 1 DFO project are properly included in this case as used and useful.

When setting just and reasonable rates the Commission must determine whether costs incurred by the utility were prudently incurred, which involves an examination of whether the utility's actions, inactions, or decisions to incur costs were reasonable based on what it knew or should have known at the time the actions, inactions, or decision to incur costs were made. When challenging prudence the challenger is required to (1) identify specific and discrete instances of imprudence, (2) demonstrate the existence of prudent alternatives, and (3) quantify the effects by calculating imprudently incurred costs. Detailed proof or analysis must also be provided. Order Granting Partial Increase in Rates and Charges, *Application by Carolina Power & Light Company for Authority to Adjust and Increase Its Electric Rates and Charges*, No. E-2, Sub 537, 78 N.C.U.C. Orders & Decisions 238, 251-52 (Aug. 5, 1988); *rev'd, in part*, *and remanded on other grounds, Utils. Comm'n v. Thornburg*, 325 N.C. 484, 385 S.E.2d 463 (1989) (*Harris Order*).

The burden of proof to show that rates are just and reasonable is on the utility. N.C.G.S. § 62-134(c). Nevertheless, intervenors have a burden of production if they dispute an aspect of the utility's prima facie case. If the intervenor meets its burden of production through the presentation of competent, material evidence, then the ultimate burden of persuasion reverts to the utility in accordance with N.C.G.S. § 62-134(c). *State ex rel. Utils. Comm'n v. Intervenor Residents of Bent Creek/Mt. Carmel Subdivisions*, 305 N.C. 62, 76, 286 S.E.2d 770, 779 (1982).

The Commission gives substantial weight to the prefiled and hearing testimony of Company witness Immel regarding the prudency of the costs of DEC's investments in its coal fleet. Witness Immel explained in detail how the Company prudently determined that these investments were needed to maintain DEC's remaining active coal units to continue to provide safe, reliable, and cost-effective electric service to customers. He explained that a significant portion of these costs were required under environmental laws or regulations regardless of whether the Company continued to run the units, and that a large portion of the remaining costs were incurred to maintain compliance with environmental requirements to continue to operate the units. Further, no party has offered concrete, specific evidence to contradict DEC's determination that it needed to continue to operate these units to serve customers.

With respect to the DFO projects, witness Immel presented convincing evidence in rebuttal and at the hearing regarding the rationale for these investments, which he testified are already resulting in savings for customers. The Commission places much weight on DEC witness Immel's testimony that the Belews Creek DFO project was placed in service on January 10, 2020, and began providing electric service to customers at that time, thereby being used and useful under the requirement of N.C.G.S. § 62-133(b)(1).

Further, the Commission concludes that no intervenor met its burden of production to challenge the Company's coal fleet investments. Sierra Club witness Wilson's recommended disallowance, as she admitted, is not specific to any particular cost. Moreover, witness Wilson testified that retiring the coal fleet all at once would likely result in reliability issues but did not identify any other prudent alternatives available to the Company. Tech Customers witness Strunk and NC WARN witness Powers, however, directed their disallowance recommendations to particular units but, aside from the DFO projects, did not identify specific costs as being imprudently incurred. In addition, the alternatives they suggested — merchant generation purchases, solar or hydroelectric generation, demand side management — are not supported by any evidence suggesting these were feasible options for the Company. No witness conducted an independent analysis using the information available at the time the Company's investment decisions were made to present evidence supporting a finding that DEC could have made another prudence choice. The evidence in the record clearly demonstrates that the Company made the best investment decisions it could with the information available at the time.

Moreover, the Commission finds persuasive witness Immel's rebuttal of witness Wilson's economic value analysis, which did not consider either the capacity value provided by DEC's coal fleet or how the Company dispatches its system as a whole on a daily basis. The Commission agrees with DEC that isolating costs invested in and the value of energy produced by a particular station on an annual basis does not accurately represent the value of the coal fleet. As witness Immel showed, even units with declining capacity factors are needed during times of high demand. For similar reasons, and because DEC must still invest in a unit to keep it available during high demand periods, the Commission does not find witness Wilson's recommendation that the Company consider operating its units seasonally to be reasonable. Finally, the Commission does not accept witness Wilson's interpretation of the term "useful" in the used and useful standard. Her reading contemplates finding an asset to be "not useful" when it was planned prudently and was impacted by changes outside the utility's control, which is not an interpretation that has been adopted by this Commission.

Finally, witness Wilson quantified her disallowance recommendation on the contention that DEC did not present evidence of the value of the investments at the time they were made. However, as witness Wilson's hearing testimony made clear, she did not consider the evidence in the 2016 Allen Station retirement study pertaining directly to this issue. As shown by witness Immel's prefiled and hearing testimony, including his testimony regarding the volume of data DEC provided to the Public Staff and intervenors in support of coal fleet investments, the Company conducted exhaustive studies of continued investments in Allen Units 4 and 5 and Cliffside Unit 5, and of the DFO projects, and relied on the results of those studies to proceed with the investments it is seeking to recover. The Commission therefore concludes that Sierra Club's contention regarding a lack of evidence is not supported by the record.

The Commission also declines to accept witness Wilson's recommendation to limit the Company's future investments in its coal fleet. Such a limitation is not necessary as the Company cannot recover any future capital investments before seeking and obtaining the Commission's approval in a future proceeding.

Finally, based on witness Immel's rebuttal testimony and witness Metz' supplemental testimony, the Commission finds and concludes that DEC's costs associated with the Belews Creek Unit 1 DFO project resulted in property used and useful and should be recovered.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 19–26

CCR Cost Recovery

The evidence supporting these findings of fact is found in the verified Application and Form E-1; the CCR Settlement between DEC, DEP, the Public Staff, the AGO, and Sierra Club; the testimony and exhibits of DEC witnesses Kerin, Bednarcik, Wells, Williams, Lioy, McManeus, and De May, Public Staff witnesses Junis, Maness, Garrett, Moore, Boswell, AGO witnesses Wittliff and Hart, Sierra Club witness Quarles, and CUCA witness O'Donnell, and the entire record in this proceeding.

Summary of the Evidence

DEC Direct Testimony

Witness Kerin

In Sub 1146 witness Kerin provided a detailed history of coal ash regulation and testified that DEC's historical coal ash management practices, those prior to the federal CCR Rule and CAMA, were reasonable, prudent, and generally comported with the industry practice of sluicing wet coal ash to unlined basins, especially in the eastern region of the country. In addition, he testified that the use of unlined basins complied with the applicable federal and state regulations. 2018 Tr. vol. 14, 99-100, 135. He testified that the Clean Water Act of 1972 and the subsequent creation of the National Pollutant Discharge Elimination System (NPDES) permitting system made wet ash handling and ash basins the primary lawful and effective way to meet CCR needs and environmental requirements from 1974 until 2015. *Id*. at 100, 106-09.

Witness Bednarcik

DEC witness Bednarcik provided an overview of the federal and state regulatory requirements applicable to DEC's coal ash basins and landfills, including the CCR Rule and CAMA, similar to that provided by witness Kerin in Sub 1146. Tr. vol. 13, 194-201. She testified that all of the coal ash remediation actions taken by DEC for which it is seeking cost recovery were required by applicable statutes and regulations and were performed in a prudent and reasonable manner. *Id.* at 215-19.

Witness Bednarcik testified that the coal ash basins at Allen, Belews Creek, Buck, Cliffside, and Marshall are classified as low risk under CAMA and, therefore, can be dewatered and closed in place. However, she stated that in April 2019, the North Carolina Department of Environmental Quality (DEQ) ordered DEC to excavate the coal ash basins at Allen, Belews Creek, Cliffside, and Marshall. Witness Bednarcik testified that prior to the DEQ order DEC had not done any site work at these basins that was specific to cap-in-place other than preliminary planning and that the site work to-date would have been required for closure by excavation. *Id.* at 201-04.

Witness Bednarcik testified regarding the activities performed and costs incurred from January 1, 2018, through June 30, 2019, at DEC's eight active coal plants. *Id.* at 204-11. She explained that the Buck plant was selected as one of three Duke Energy sites for a beneficiation project pursuant to CAMA. She stated that DEC will close the impoundments at Buck by excavation and that the coal ash from Buck will be processed through the beneficiation plant for use in the concrete industry rather than being placed in a lined landfill. She stated that DEC selected The SEFA Group, Inc.'s STAR technology to process the coal ash from Buck and that construction of the beneficiation plant began in May 2018, including construction of a sedimentation basin and the foundations and support structures for the beneficiation plant. *Id.* at 207-08.

Witness Bednarcik further testified that in 2014 Duke Energy executed contracts with Charah, LLC, to dispose of coal ash from DEC's Riverbend plant and DEP's Sutton, Cape Fear, H.F. Lee, and Weatherspoon plants. She stated that the contracts required Duke to provide a minimum amount of coal ash and that due to changing circumstances caused by CAMA amendments, Duke did not provide the minimum amount of coal ash to Charah. As a result, Duke incurred a fulfillment charge of $80 million, and $46,329,946 of the fulfillment charge has been allocated to DEC for Riverbend "as well as future estimated costs for leachate management, capping the landfill, and post closure maintenance." *Id.* at 212-13.

AGO Direct Testimony

Witness Wittliff

Witness Wittliff testified in Sub 1146 that based on his professional training and experience, DEC did not operate its coal ash basins in a manner designed to meet environmental regulations and to ensure that the basins were properly managed. 2018 Tr. vol. 11, 230-42. Specifically, he testified that since the 1970s the industry showed a gradual shift away from surface impoundments towards landfills and away from unlined basins to lined waste management units. *Id.* at 252. He further testified that DEC failed to follow this movement, and he stated that in 2017 the Company continued to employ a combination of wet unlined surface impoundments, unlined landfills, and ash stack areas at all of its coal plants. *Id.* On cross-examination in that proceeding, however, witness Wittliff stated that costs incurred by the Company to comply with the CCR Rule were reasonable and prudent, *id*. at 282-83, and he admitted that he did not identify any specific costs that could have been lower or should be disallowed. *Id*. at 287-89.

Witness Hart

In the current rate case witness Hart discussed the CCR Rule, CAMA, the 2L rules, and other environmental guidelines applicable to coal ash basins. Tr. vol. 16, 709-18. Witness Hart testified that unlined coal ash basins cause groundwater contamination. He explained that the metals present in the coal ash leach out of the ash, enter a dissolved state, and become coal ash "leachate," and that because a hydraulic head is maintained in the basin the metals-laden water in the basin migrates downward into underlying soil. *Id*. at 742-47. Witness Hart discussed several industry and government studies and reports, similar to those noted by other witnesses, that he opined placed the electric utility industry on notice of the potential leaching of coal ash metals into groundwater.

Witness Hart provided the details of the coal ash basins and groundwater monitoring at each of DEC's coal plants. In addition, he included graphs for each plant showing the most prominent coal ash constituents. *Id*. at 769-820; AGO Hart Direct Exs. 40-54. Witness Hart concluded that prior to the Dan River coal ash spill DEC did not take reasonable and prudent actions to address groundwater contamination at its coal ash basins and to close the basins. *Id.* at 821-24. Witness Hart testified that DEC's inaction increased its present coal ash remediation costs because the Dan River spill prompted accelerated remediation actions, which are always more costly. Witness Hart attempted to quantify this increased cost and stated that earlier action by DEC would have resulted in cost recovery while the coal plants were still in use, and at a lower cost.

Public Staff Direct Testimony

Witness Junis

In his Sub 1146 testimony, witness Junis testified that DEC and DEP have over 100 million tons of coal ash stored in landfills and basins in North Carolina. He provided a summary of the CCR Rule, CAMA, the 2L standards, and other environmental legislation and regulations. He stated that CCR basins contain certain elements that can pollute groundwater, waterways, and drinking water, including arsenic, boron, lead, aluminum, cadmium, sulfate, and vanadium.

Witness Junis testified that DEC voluntarily installed most of its groundwater monitoring wells in and around 2010 but installed a few at Cliffside and Dan River as early as November 1993. Further, he testified that there were six coal plants where DEC did not monitor groundwater until 2004 or later. *Id*. at 700-03. He stated that violations of 2L standards were detected near on-site landfills as early as 1989 at Belews Creek and Marshall. In addition, based on data request responses from DEC, he testified that as of 2017 all of DEC's North Carolina coal ash basins had groundwater exceedances in violation of the 2L rules. *Id.*; 2018 Junis Direct Ex. 20.

In addition, witness Junis testified that DEC had identified 98 unpermitted seeps at its coal ash basins as of 2014 and later. *Id*. at 704-19; 2018 Public Staff Wright Cross-Exam Ex. 2. He stated that some of the costs for corrective action, which DEC labels as compliance costs to meet the requirements of the CCR Rule and CAMA, are actually for corrective action necessitated by noncompliance with longstanding environmental regulations. *Id*. at 732-37.

Witness Junis stated that the Public Staff believes it is appropriate to assign to DEC the responsibility for costs to defend against environmental violations and costs to remedy those violations, except to the extent that CAMA imposed new requirements that increased the cost of remediation. He stated, however, that there were instances in which DEC's actions were prudent, that separating out the imprudent costs would be complex, and that the calculation of some costs of imprudence would be speculative. Therefore, the Public Staff recommended an equitable sharing, with 50% of the CCR costs being paid by shareholders and 50% by ratepayers. *Id*. at 737-742.

In the present docket, witness Junis reiterated and updated his Sub 1146 testimony. He testified that the Public Staff continues to pursue its 50/50 equitable sharing recommendation and that the equitable sharing proposal is not based on these actions being deemed imprudent. Tr. vol. 20, 406-23, 429-31, 462-67.

Witness Junis described the settlement reached by DEC, DEQ, and several environmental parties on December 31, 2019. He explained that DEC will excavate and move to lined basins most of the coal ash at DEC's Allen, Belews Creek, Cliffside, and Marshall plants, and at DEP's Mayo and Roxboro plants. He testified that excavation and removal has been completed at Dan River and Riverbend, that DEC's Buck plant is a beneficiation project, and that the W.S. Lee plant in South Carolina is not covered by CAMA. *Id*. at 423-27.

Witness Junis concluded his testimony with the Public Staff's recommendations for disallowance of the following costs: (1) costs spent by DEC to install wells for the extraction and treatment of groundwater at Belews Creek; (2) costs to provide bottled water, water connections to municipal or county systems, and water treatment systems; and (3) fines and penalties for environmental violations. He stated that the above disallowances are in addition to those recommended by Public Staff witnesses Garrett and Moore. *Id*. at 455-62.

Witness Maness

In his testimony in the present docket, witness Maness discussed the three coal ash cost adjustments being proposed by the Public Staff: (1) the disallowances recommended by witnesses Junis, Moore and Garrett; (2) an amortization period of 26 years; and (3) the reversal of DEC's inclusion of coal ash costs in rate base. Tr. vol. 20, 495-98.

Witness Maness testified that the Public Staff believes there should be an equitable sharing of the coal ash costs between ratepayers and shareholders. He explained that an equitable sharing can be achieved by, first, excluding the coal ash costs from inclusion in DEC's rate base and, second, using a longer amortization period. *Id*. at 498-507, 514-17. Witness Maness testified that the five-year amortization period proposed by DEC is too short. He stated that the CCRs are the result of decades of generating electricity by coal and that associated costs should be amortized over a similarly lengthy period. The Public Staff, therefore, recommends an amortization period of 26 years.

With respect to DEC's future coal ash costs, witness Maness testified that the Public Staff agrees that DEC should be allowed to defer its future costs in a regulatory asset and accrue a return on the deferred balance at the net-of-tax overall return authorized by the Commission for DEC during the deferral period. *Id*. at 519-20.

Witness Garrett

Witness Garrett, a registered professional engineer and a consultant with the engineering firm Garrett and Moore, testified that he investigated the prudence and reasonableness of the costs DEC incurred at its two high-priority sites under CAMA, Riverbend and Dan River. Witness Garrett stated that Charah was retained to provide disposal capacity at the Brickhaven mine for ash from DEC's Riverbend Station and from DEP's Sutton Station. Based on his investigation witness Garrett recommended that the

Commission disallow certain costs DEC seeks to recover related to the fulfillment fee the Company paid to Charah that are not reasonable and prudent. Tr. vol. 20, 201-04. Witness Garrett further concluded that DEC paid a significant premium for coal ash excavation and disposal at Riverbend regarding work begun by Parsons Environment & Infrastructure Group, Inc., and ultimately completed by Trans Ash, Inc., and he recommended a disallowance related to these costs as not reasonable and prudent. *Id*. Witness Garrett opined that DEC had other more prudent options that would have avoided the additional costs, including: (1) requesting a variance of the CAMA deadline; (2) negotiating new rates with Parsons; (3) having a performance bond with Parsons; or (4) imposing back charges on Parsons for work completed by Trans Ash. *Id.* at 237-41.

Witness Moore

Witness Moore, a registered professional engineer and a consultant with the engineering firm Garrett and Moore, testified that he investigated the prudence and reasonableness of DEC's CAMA compliance costs at Allen, Belews Creek, Buck, Cliffside, and Marshall. He stated that he takes no exception with DEC's CCR costs for work at Allen, Belews Creek, Cliffside, and Marshall. Tr. vol. 20, 168, 172-75.

Witness Moore recommended a disallowance of certain costs incurred in the construction of the Buck beneficiation project. He described the Request for Information (RFI) process by which Duke chose SEFA and SEFA's STAR beneficiation system for DEC's Buck and DEP's Lee and Cape Fear beneficiation projects. He stated that he agrees with Duke's choice of SEFA and does not take exception to the subsequent change orders submitted by SEFA or the costs associated with those change orders. *Id.* at 186-87, 190. However, witness Moore testified that he does not agree with the choice of Zachry Industrial, Inc., as the general contractor. He testified that readily available information shows lower capital costs for a similar SEFA project in South Carolina and opined that Duke could have attempted to mitigate the construction costs by rebidding the contract, entering into three separate construction contracts, obtaining an amendment to CAMA, or obtaining guidance from DEQ. *Id.* at 185-191. Based on his determination that the Company's selection of Zachry to construct the beneficiation unit at the Buck Station for the amount contracted was unreasonable and imprudent, witness Moore recommended that the Commission disallow a portion of the construction costs for the Buck beneficiation facility.

Sierra Club Direct Testimony

Witness Quarles

Witness Quarles testified on behalf of the Sierra Club in both Sub 1146 and the present DEC rate case. Witness Quarles reiterated in this case his testimony in Sub 1146 that the Company "continued to build new unlined disposal areas and expand existing ones through the 1990s, to operate unlined surface impoundments through the present day, and to stack wastes on top of unlined disposal areas — even though utilities around the United States have been constructing lined disposal areas since the mid-1970s and despite an understanding of contamination risks associated with disposal in unlined ponds." Tr. vol. 18, 31-32. He testified further that "[s]ince at least the mid-1970s, it was reasonable for the Company to expect CCR contamination of groundwater and surface waters because of its use of unlined surface impoundments," and that on-going leaching of coal ash constituents from the Company's unlined surface impoundments has resulted in groundwater contamination beneath and downgradient of the disposal areas that has exceeded DEQ and EPA standards. *Id*. at 32.

In the current rate case witness Quarles focused in his testimony on "determining *when* the Company knew or should have known that groundwater or surface water contamination was likely due to storage and disposal of CCRs in unlined areas located near — and even sometimes within — rivers and streams and where the ash is saturated with groundwater." *Id*. at 28. Witness Quarles concluded that DEC's costs to excavate the coal ash and for groundwater monitoring at Allen could have been lower if DEC had converted to dry ash handling sooner. He recommended that the Commission conclude that DEC's continued operation of unlined basins after the industry recognized the risks was unreasonable and that DEC's failure to take action at Allen after its 1984 investigation revealed groundwater contamination was unreasonable. Further, he provided no disallowance recommendation but testified that costs associated with excavation and groundwater monitoring today likely would be lower if DEC had converted to dry ash disposal in lined landfills sooner. *Id.* at 57-59.

CUCA Direct Testimony

Witness O'Donnell

Witness O'Donnell discussed the Dan River spill and DEC's guilty plea for other unauthorized discharges of coal ash pollutants. He cited an early draft of CAMA and statements by legislators to support his contention that Duke's environmental violations caused the General Assembly to enact CAMA, and, therefore, DEC should not be permitted to recover from customers any coal ash costs above those that DEC would have incurred under the CCR Rule. Tr. vol. 20, 59-70.

DEC Rebuttal Testimony

Witness Bednarcik

Witness Bednarcik responded to the Public Staff's contention that DEC's cost of installing extraction wells and treating the groundwater at Belews Creek should be disallowed. She testified that the amount spent by DEC to install wells for the extraction and treatment of groundwater at Belews Creek was incurred for the same purposes as that approved by the Commission for recovery in DEC's previous rate case and should likewise be approved. Tr. vol. 24, 91-93. With regard to DEC's installation of permanent water supplies and water treatment systems, witness Bednarcik stated that this work is required by CAMA and that the costs should be recoverable by the Company. *Id.* at 93-96. With respect to the Public Staff's equitable sharing recommendation, witness Bednarcik testified that this proposal has now been rejected by the Commission three times and that it continues to lack any basis under the standard for recovery of prudent and reasonable costs. *Id.* at 48-49, 96-98.

In response to AGO witness Hart's proposed cost disallowance quantification, witness Bednarcik testified that his quantification implicitly rejects the idea that DEC could have used closure strategies different from today if it had it begun such activities in 1989, 1993, 2003, or 2010. She further testified that it is impossible to retroactively predict with any degree of certainty what options the Company might have pursued had it chosen to close its inactive basins in 1989, 1996, 2003, or 2010 given the historical regulatory landscape, available technology, and evolving industry best practices. Lastly, she stated that as DEC rebuttal witness Lioy discusses, AGO witness Hart's calculations simply show the equivalent of today's closure costs reduced based on rates of inflation. *Id.* at 105-07.

In response to Public Staff witness Garrett's recommended disallowance for costs associated with excavation and disposal at Dan River, witness Bednarcik testified to deficiencies in performance that led to termination of the Parsons contract by DEC. She testified that DEC formally informed Parsons that absent immediate improvement, DEC would be forced to consider termination. She testified that after several meetings with Parsons' executive leadership, Parsons was ultimately unable to demonstrate to the Companies that it was equipped to properly excavate the coal ash basins at Dan River, and particularly not in accordance with CAMA's required timeline. *Id.* at 67.

Witness Bednarcik further testified in response to witness Garrett's contentions about other options that were available to DEC rather than termination of the Parsons contract. She testified that having a performance bond with Parsons and negotiating new rates would not have improved Parsons' performance to the extent needed to meet the CAMA deadline and that there were no grounds for imposing back charges because Parsons did the work properly. She testified that none of Parsons' work had to be redone by Trans Ash. Further, she stated that even if DEC had requested and DEQ had granted a variance from the August 1, 2019 deadline, there was no guarantee that Parsons would have been able to meet the new target date. *Id*. at 66-76.

In response to Public Staff witness Moore's recommended disallowance for the Zachry contract, witness Bednarcik explained that the estimate SEFA provided was based on the costs it incurred to construct the Winyah STAR facility in South Carolina, but that there are several key differences between the Winyah and Buck projects that would impact cost, including: (1) the Winyah plant is designed to produce 200,000 tons of ash product per year (a 120 MMBtu facility), while the Buck project must produce 300,000 tons of ash product per year (a 140 MMBtu facility) to meet CAMA requirements, which requirement necessitated installation of a second external heat exchanger at Buck along with all associated equipment; (2) Winyah typically uses 70% ponded ash and 30% production ash, but ash at DEC's plants is 100% ponded ash and required the addition of a grinding circuit to meet American Society for Testing Materials (ASTM) standards for concrete; (3) the two facilities use different scrubbers, and the dry scrubbers at Buck required a second bag house with additional induced draft fans; and (4) the Winyah facility was a refurbishment/addition to an existing carbon burn-out facility and SEFA was able to reuse a significant part of the carbon burn-out facility when constructing Winyah's plant, whereas the DEC facilities are new construction. Tr. vol. 25, 82-84.

In addition, witness Bednarcik stated that witness Moore's suggestion that the Company should have sought statutory relief from CAMA's beneficiation requirements is not realistic. She stated that there is no guarantee that the General Assembly would have granted such relief and that even if it had been willing to do so, it is likely that the original CAMA deadline would have passed before such a bill could be drafted, vetted, and passed. Likewise, witness Bednarcik testified that witness Moore's suggestion that the Company should have sought guidance from DEQ upon learning of Zachry's estimated costs is also misguided because DEQ is responsible for enforcing the State's environmental laws irrespective of an entity's cost of compliance, and there are no cost considerations in the beneficiation provisions of CAMA. In response to witness Moore's contention that DEC should have rebid the project with a larger pool of potential bidders, witness Bednarcik stated that DEC wanted to contract with a contractor that was currently working with the Companies or had worked with the Companies, and a contractor with a North Carolina presence. With respect to witness Moore's suggestion that the Companies could have selected three different contractors for their three beneficiation projects, she stated that by contracting with Zachry for all three projects DEC was able to realize extensive cost savings through economies of scale. She opined that based on the scope, novelty, and difficulty of the Buck project the costs paid to Zachry were reasonable and prudent. Id. at 86-87.

Witness Wells

DEC witness Wells reiterated much of his testimony in Sub 1146 about the industry and regulatory standards and DEC's compliance with those standards. Tr. vol. 27, 27-32. He noted that the Commission rejected the Public Staff's equitable sharing recommendation in the 2018 DEC Rate Order. He also asserted that no intervenor witness had attempted to quantify alleged imprudent costs caused by DEC's historical management of coal ash. *Id.* at 25-27.

Witness Wells testified that DEC met its responsibility to comply with NPDES permitting requirements. Witness Wells noted that witness Junis suggested that the existence of seeps at DEC's coal ash impoundments is evidence of the Company's "culpability." However, asserted witness Wells, this suggestion ignores the fact that: (1) seeps are a natural and even necessary consequence of earthen impoundments; (2) EPA first directed permitting authorities to address seeps in 2010; (3) the Company made attempts to obtain regulatory certainty as to seeps; and (4) DEQ faced challenges in implementing EPA's directives on seeps. *Id.* at 56-51. Witness Wells testified that DEC has taken a measured and responsible approach, consistent with the rules and regulations, to address potential environmental impacts from its surface impoundments — monitoring and, if needed, taking corrective action to safeguard against impacts to receptor wells, surface water, and offsite property. *Id.* at 35-46.

Witness Wells discussed DEC's agreement with DEQ and cited several other developments that he stated are evidence of DEC's diligence in working with environmental regulators to improve DEC's coal ash facilities, including: (1) the conversion to dry bottom ash handling at Allen, Belews Creek, Cliffside, and Marshall, plus the beginning of decanting at these sites; (2) the submission of Corrective Action Plans to DEQ for Allen, Belews Creek, Cliffside, and Marshall; and (3) completion of excavation and removal of all coal ash at Dan River and Riverbend. *Id.* at 66-69. In response to questions from the Commission, witness Wells testified that it was prudent for DEC to wait until the CCR Rule was final to decide to dispose of coal ash in a manner other than unlined basins. Tr. vol. 28, 124-27.

Witness Williams

Witness Williams, who worked for the EPA for 17 years and served as Director of the Office of Solid Waste until 1988, testified regarding the history of coal ash regulations and the evolution of the CCR Rule. She stated that owners and operators of coal ash basins in North Carolina faced significant uncertainty regarding regulatory requirements until adoption of the CCR Rule and CAMA, and based on these uncertainties, owners and operators of coal ash basins acted prudently by waiting for adoption of the CCR Rule and CAMA to take specific actions to upgrade or close coal ash basins. *Id.* at 104-07. She discussed several factors that compound uncertainty in EPA regulation, including participation of diverse interests, length and complexity of the process, collection of new information, additional analyses required by Executive Orders, changes in administrations, court challenges, and Federal/State interface. *Id.* at 108-14. She stated that DEC did not act imprudently by waiting for regulatory clarity so long as it continued to work with regulatory agencies to address site specific environmental risks. She discussed the efforts made by DEC in the late 1970s and early 1980s to evaluate coal ash constituents and leachate using EPA-sanctioned testing methods, particularly at its Allen and Riverbend plants. Witness Williams stated that DEC took the prudent and appropriate steps to evaluate potential impacts of its coal ash basins on groundwater and surface waters prior to the new requirements included in the CCR Rule and CAMA. *Id.* at 128-39.

With respect to the testimony of witnesses Junis, Quarles, and Hart, witness Williams stated that they failed to consider all relevant information in assessing DEC's historic actions, including selectively using information from studies and reports without considering the broader set of available knowledge on the subject, failing to give appropriate weight to environmental regulations, and failing to assess in detail industry practices in CCR and other waste management. Further, she asserted that they failed to give appropriate weight to the role of DEQ in overseeing DEC's actions. She stated that the fact that DEQ did not require liners, closure of basins, or mandate groundwater monitoring earlier is a strong indication that DEC was managing CCRs in a prudent and reasonable manner. *Id.* at 146-53.

Witness Williams took issue with AGO witness Hart's conclusion that DEC's coal ash remediation costs are higher today than they would be if DEC had been prudent in managing its coal ash. Witness Williams contended that witness Hart's cost disallowance calculations are entirely speculative because there is no way to predict what would or could have been done with respect to coal ash disposal on these earlier dates and how the cost of those activities would compare to the actions that DEC is taking today.

According to witness Williams, Hart's analysis fails to recognize that DEC's coal ash disposal costs could have been higher if DEC had initiated some type of closure action earlier that later proved to be unnecessary or imprudent. *Id.* at 174-84.

Witness Lioy

Witness Lioy testified that AGO witness Hart attempted to quantify the amount that DEC would have spent as of the earlier time periods in his analysis (1989, 1993, 2003 and 2010) in order to quantify alleged imprudently incurred costs. According to witness Lioy, witness Hart did not accomplish that goal because there are a number of factors that would need to be considered to determine what DEC would have spent in 1989, or as of any of the other earlier time periods, including different applicable laws and regulations in 1989, and different technologies, means, and methods available in 1989. *Id.* at 169-72. Witness Lioy concluded that witness Hart's calculations were not prepared in accordance with normal conventions and are unreliable and speculative. *Id.*

Witness McManeus

Witness McManeus testified that the Company opposes the Public Staff's equitable sharing proposal and witness Maness's recommendations to lengthen the amortization for CCR cost recovery and disallow a return during the amortization period. She explained that the Public Staff's equitable sharing adjustment runs directly contrary to well-established ratemaking and cost recovery principles and, in particular, the basic principle that a public utility's reasonable and prudently incurred costs are recoverable in rates. She noted that the Public Staff's approach does not depend on any finding of imprudence but merely adopts an arbitrary amortization period necessary to achieve a 50/50 split of the CCR costs between the Company and its ratepayers. Witness McManeus further testified that it is appropriate for the Commission to allow the Company to recover its financing costs during the amortization period, as the Public Staff acknowledges is appropriate during the initial deferral period. She states that the costs at issue include the cost of money, that the financing costs are related to funds advanced by investors, and that the costs are necessary and prudent to ensure reliable electric service. Lastly, she noted that the Commission rejected the Public Staff's equitable sharing proposal in DEC's 2018 rate case. Tr. vol. 11, 528-33

DEC Settlement Testimony

Witness De May

In support of the January 25, 2021 CCR Settlement witness De May testified that the CCR Settlement represents a balanced solution that resolves the coal ash cost recovery debate in North Carolina, providing both immediate and long-term savings for customers and long-term certainty for the Company and its investors and allowing all parties to move forward towards the desired cleaner energy future. He concluded that the CCR Settlement is in the public interest and should be approved.

Witness De May provided an overview of the CCR Settlement. He testified that it resolves among the Settling Parties, subject to Commission approval, CCR cost recovery issues in both DEP's and DEC's current rate cases and the Companies' prior cases in a comprehensive manner for the period beginning January 1, 2015 (when the Company first incurred such costs), through January 31, 2030 — a period of over fifteen years. Witness De May contended that the CCR Settlement requires the Company to reduce the amount of coal ash-related costs to be recovered from customers and grants the Company the ability to earn a return upon the recovered costs at a negotiated cost of equity lower than the Company's allowed ROE. The CCR Settlement also provides customers with immediate and future rate reduction — DEP and DEC together will absorb approximately $1.1 billion (on a North Carolina system basis) through February 2030. Witness De May testified that on a North Carolina retail basis, the net present value of the cost savings to customers (including applicable financing costs) is in excess of $900 million. Importantly, witness De May noted, a large portion of the rate reduction will occur over the near term, during a period in which many customers are suffering severe economic hardship from the COVID-19 pandemic.

Witness De May also summarized the benefits of the CCR Settlement to the Company. He explained that it "validates and affirms the reasonableness and prudence of [each] Company's ash basin closure strategy," provides more certainty and stability regarding cost recovery, and — by preserving the Companies' ability to recover financing costs, albeit at a reduced rate — preserves their access to much needed capital on reasonable terms, also benefitting customers. Finally, the CCR Settlement — in settling the legacy issue — allows the collective focus to shift to the future to cleaner sources of energy, while maintaining the Company's drive to keep electricity affordable and reliable.

Witness De May explained that the CCR Settlement appropriately balances the need for rate relief with the impact of such rate relief on customers. He stated that the Company is pleased that its rates are competitive and below the national average and will remain so under the CCR Settlement, noting that providing safe, reliable, and increasingly clean electricity at competitive rates is key. Witness De May stated that, particularly in light of the current economic conditions faced by customers due to the COVID-19 pandemic, the Company believes the CCR Settlement fairly balances the needs of customers with the Company's need to recover substantial investments made in order to continue to comply with regulatory requirements and safely provide high quality electric service. Given the size of the necessary capital and compliance expenditures the Company faces, it is essential that DEC maintain its financial strength and credit quality for the benefit of our customers.

Witness McManeus

Witness McManeus similarly testified that the Company believes that the CCR Settlement represents a fair, just and reasonable, and balanced solution that provides immediate and long-term savings for customers as well as the long-term certainty the Company and its investors need. Thus, the Company requests that the Commission approve of the CCR Settlement in its entirety. The effect of the CCR Settlement on the Company's requested recovery of CCR costs is shown on McManeus CCR Settlement

Exhibit 1, page NC-1102. As set forth thereon, the CCR Settlement provides for DEC to recover $117,658,176 of actual coal ash basin closure and compliance costs plus financing costs of $51,869,890.

Witness McManeus testified that if the Commission approves the CCR Settlement and the First and Second Partial Stipulations with the Public Staff, the Company's revised request for a revenue increase in base rates is reduced to $357 million. She explained that McManeus CCR Settlement Exhibit 2 shows that the Company's revised request for a revenue increase, combined with the Company's request to reduce customer rates by $295 million through its proposed EDIT rider, results in a net proposed increase in revenue of $62 million — a $229 million reduction from the amount proposed in the Company's Application. She further noted that these amounts assume the Commission accepts the Company's position on the remaining unsettled revenue issues, which are depreciation rates and the appropriate amortization period for the Company's loss on the sale of hydro stations. The other nonrevenue issues concern various forward-looking studies and rate designs.

Public Staff Settlement Testimony

Witness Maness

Witness Maness testified that the CCR Settlement would comprehensively resolve the following CCR cost recovery issues: (1) issues pending before the Commission on remand in the 2018 Rate Cases; (2) issues pending before the Commission in the present rate case proceedings; (3) the treatment of CCR costs incurred by DEC from February 1, 2020, through January 31, 2030, and by DEP from March 1, 2020, through February 28, 2030, along with associated financing costs; and (4) how any proceeds received from insurance litigation related to CCR costs would be shared by ratepayers, DEC, and DEP.

In addition, witness Maness explained that from the perspective of the Public Staff, the most important ratepayer benefits of the Agreement are: (1) DEC's and DEP's agreement to forego the combined recovery of CCR costs and associated financing costs in excess of $900 million, on a present value basis, resulting in a significant reduction in the proposed revenue increase in this case; (2) the allocation of the proceeds of CCR insurance litigation; and (3) the avoidance of protracted litigation over CCR costs and financing costs into 2030. Accordingly, witness Maness stated that the Public Staff believes the CCR Settlement is in the public interest and should be approved.

Witness Boswell

Witness Boswell provided updated schedules showing the impact of the CCR Settlement. She noted that some final adjustments will have to be made after the Commission's issues its order resolving the remaining unsettled issues.

Public Witness Testimony and Consumer Statements of Position

Over the course of the four public witness hearings held in the instant case, during which a total of 70 public witnesses provided testimony to the Commission, many of the witnesses expressed concerns to the Commission regarding the environmental impact of, the handling of, and the costs associated with CCRs.[3] Similarly, many of the written consumer statements of position filed in this proceeding addressed the issues of the environmental impact of, the handling of, and the costs associated with CCRs.

Discussion and Conclusions

The Commission is required to set just and reasonable rates for public utilities. N.C.G.S. § 62-130(a). Just and reasonable rates are those that provide the utility an opportunity to earn a fair return on its property and are fair to the utility's customers. *State ex rel. Utils. Comm'n v. Piedmont Nat. Gas Co.*, 254 N.C. 536, 119 S.E.2d 469 (1961); *State ex rel. Utils. Comm'n v. Duke Power Co*., 285 N.C. 377, 206 S.E.2d 269 (1974). To achieve just and reasonable rates, the utility's revenue must be sufficient to cover the utility's cost of service, plus allow the utility the opportunity to earn a reasonable return on its rate base but must be fair to customers. To this end, the North Carolina Supreme Court has counselled:

> [T]he fixing of "reasonable and just" rates involves a balancing of shareholder and consumer interests. The Commission must therefore set rates which will protect both the right of the public utility to earn a fair rate of return for its shareholders and ensure its financial integrity, while also protecting the right of the utility's intrastate customers to pay a retail rate which reasonably and fairly reflects the cost of service rendered on their behalf.

State ex rel. Utils. Comm'n v. Nantahala Power & Light Co., 313 N.C. 614, 691, 332 S.E.2d 397, 474 (1985), *rev'd on other grounds*, 476 U.S. 953, 106 S. Ct. 2349, 90 L.Ed.2d 943 (1986), *appeal after remand*, 324 N.C. 478, 380 S.E.2d 112 (1989) (*Nantahala*).

The burden of proof to show that rates are just and reasonable is on the utility. N.C.G.S. § 62-134(c). However, according to the North Carolina Supreme Court,

> [i]n spite of the fact that North Carolina utilities have the burden of proving that the costs upon which their rates are based are reasonable and prudent, the reasonableness and prudence of those costs is "presumed" unless the Commission or an intervenor adduces sufficient evidence to cast doubt upon their reasonableness or prudence, at which point the burden to make an affirmative showing of the reasonableness of the costs in question shifts to the utility. *State ex rel. Utils. Comm'n v. Intervenor Residents of Bent Creek/Mt. Carmel Subdivisions*, 305 N.C. 62, 76, 286 S.E.2d 770, 779 (1982) (*Bent Creek*). In order to satisfy this burden of production, an

[3] Franklin (8/10 witnesses), Morganton (2/5 witnesses), Graham (12/25), Charlotte (18/30).

> intervenor must offer affirmative evidence tending to show that the expenses that the utility seeks to recover "are exorbitant, unnecessary, wasteful, extravagant, or incurred in abuse of discretion or in bad faith or that such expenses exceed either the cost of the same or similar goods or services on the open market or the cost similar utilities pay to their affiliated [utilities] for the same or similar goods or services." *Id.* at 76–77, 286 S.E.2d at 779. If a utility expense is "properly challenged," "[t]he Commission has the obligation to test the reasonableness of such expenses." *Id*. at 76, 286 S.E.2d at 779.

State ex rel. Utils. Comm'n v. Stein, 375 N.C. 870, 908, 851 S.E.2d 237, 261-62 (2020) (second and third alterations in original) (*Stein*). The Supreme Court thereafter held that "the record contain[ed] ample evidentiary support for the Commission's determination in the Duke Energy Carolinas proceeding that the intervenors had failed to elicit sufficient evidence to satisfy the burden of production imposed upon them in *Bent Creek*." *Id*. at 911, 851 S.E.2d at 263.

Finally, the Commission's orders must be based on competent, material, and substantial evidence in the record of the instant proceeding. N.C.G.S. § 62-65(a). Where settlement has been reached by less than all of the parties in a case, as with the CCR Settlement in this case, that settlement should be accorded full consideration and weighed by the Commission along with all other evidence presented in reaching its decision: "The Commission may even adopt the recommendations or provisions of the nonunanimous stipulation as long as the Commission sets forth its reasoning and makes 'its own independent conclusion' supported by substantial evidence on the record that the proposal is just and reasonable to all parties in light of all the evidence presented." *CUCA I*, 348 N.C. at 466, 500 S.E.2d at 703.

The issues related to the recovery of costs incurred to comply with CAMA and the CCR Rule have been highly contentious in the last several electric utility rate cases. The parties to the proceedings have proffered pages and hours of testimony reviewing the history of coal-fired generation and the handling of coal ash throughout the history of the utilities serving North Carolina consumers, comparing the past coal ash handling practices of these utilities to others across the region and the country, debating what different decisions perhaps should have been made and when, and attempting to quantify the impact of such decisions on the CCR costs sought to be recovered from customers. Additionally, the Commission has received significant testimony from public witnesses on these issues. Indeed, coal ash — including environmental impact and associated cost — was the predominant topic at the public witness hearings held in this case.

As noted above, the Public Staff has argued that responsibility for these costs (not otherwise imprudently incurred) should be shared equally between the utility and its customers. Other parties have argued that the utility should bear all or substantially all of the costs of compliance with the recently adopted state and federal requirements. After careful consideration, the Commission determined in DEC's and DEP's 2018 rate cases that the costs incurred, with one exception, were reasonable and prudent but imposed a management penalty in each case, which ultimately reduced the return that each Company would recover during the five-year amortization period.

Upon appeal of the Commission's 2018 rate case orders on this issue, the North Carolina Supreme Court remanded the cases to the Commission for further proceedings to consider the Public Staff's equitable sharing proposal. In summary, the Court concluded

> that the Commission did not err by: (1) allowing the inclusion of a large majority of the utilities' coal ash costs in the cost of service used for the purpose of establishing the utilities' North Carolina retail rates; (2) interpreting N.C.G.S. § 62-133(d) to authorize the Commission, in the exercise of its discretion, to allow a return on the unamortized balance of the deferred operating expenses . . . . On the other hand, we hold that the Commission erred by rejecting the Public Staff's equitable sharing proposal without properly considering and making findings and conclusions concerning "all other material facts" as required by N.C.G.S. § 62-133(d). As a result, we affirm the Commission's decisions, in part, and reverse and remand the Commissions' decisions for further proceedings not inconsistent with this decision, in part.

Stein, 375 N.C. at 946-47, 851 S.E.2d at 286.

The Court's opinion was issued on December 11, 2020 — after the close of the evidentiary record in the instant case. Subsequent to the issuance of the opinion, the CCR Settling Parties — each of which had offered evidence on the issue of CCR cost recovery in the rate cases and had participated in the appeals of the Commission's 2018 rate case orders — worked to reach a compromise on the issues. The CCR Settlement seeks to resolve not only the current DEC rate case but the current DEP rate case, the 2018 rate cases that have been remanded back to the Commission, and future CCR costs to be incurred through January 2030 for DEC and February 2030 for DEP.

On February 12, 2021, upon joint motion of the CCR Settling Parties, the Commission issued an order reopening the evidentiary records, allowing testimony or comments on the CCR Settlement, and allowing requests for hearing by any party. The order made clear that a party's choice not to file a request for a hearing would be deemed by the Commission as a waiver by that party of its right to cross-examine the witnesses who provided testimony regarding the CCR Settlement. No testimony or comments were filed by any party, and no party requested a hearing. Thus, all parties waived their rights to introduce additional testimony or to cross-examine DEC's or the Public Staff's witnesses on their settlement testimony. The Commission will accept the CCR Settlement and the subsequently filed testimony in support of the CCR Settlement into the record of evidence in this case.

The Commission recognizes that the CCR Settlement is the product of give-and-take between the CCR Settling Parties — DEC, DEP, the Public Staff, the AGO, and the Sierra Club. The settlement and supporting testimony by the parties offer an immediate and longer-term resolution of the ratemaking treatment of CCR costs in lieu of the positions previously advocated by the parties. The agreement aims to resolve contentious issues in this and other DEP and DEC rate cases, including the 2018 rate cases, and strikes a balance between the Companies and their customers that all of the CCR Settling Parties found to be appropriate. The Company explains that the CCR Settlement provides benefit to customers through both immediate and future rate reduction — DEC and DEP together will absorb approximately $1.1 billion (on a North Carolina system basis) in CCR-related costs over the time period covered by the CCR Settlement, reducing the amounts they would otherwise seek to recover from customers. On a North Carolina retail basis, the net present value of the savings to customers from forgone CCR cost recovery (including applicable financing costs) amounts to more than $900 million. Importantly, a large portion of the rate reduction will occur over the near term, during a period in which many customers are suffering severe economic hardship from the COVID-19 pandemic. De May Settlement Testimony at 4:11-20. The Commission takes note that the Public Staff generally supports this position, asserting that the agreement obligates DEC and DEP to forego recovery of costs in excess of $900 million (combined DEC and DEP), resulting in a significant reduction in the proposed revenue increase in this case. Maness Settlement Testimony at 5:14-19.

The Commission recognizes that for purposes of this proceeding DEC agrees in the CCR Settlement to reduce the balance of deferred CCR costs to be recovered in this rate case by $224 million. DEC will cease to accrue financing costs on this amount as of December 31, 2020, resulting in additional savings to customers. Additionally, the CCR Settlement provides that DEC will recover the remaining balance of its deferred costs over a five-year amortization period, plus reduced financing costs during the amortization period calculated based on (1) DEC’s cost of debt set forth in the Second Partial Stipulation, adjusted as appropriate to reflect the deductibility of interest expense, (2) an ROE 150 basis points lower than the 9.60% ROE set forth in the Second Partial Stipulation, and (3) a capital structure of 48% debt and 52% equity set forth in the Second Partial Stipulation.

For purposes of future rate case proceedings DEC has agreed to reduce the balance of CCR costs to be recovered by $108 million and agrees that this amount shall also cease to accrue financing costs as of December 31, 2020, which provides additional savings to customers. DEC has agreed to recover financing costs during the amortization period established in future proceedings at a reduced rate.

Finally, the Commission notes that the CCR Settling Parties have agreed to waive their rights to challenge future CCR costs on the basis that the Company’s historical coal ash management practices were inadequate and led to unreasonable CCR costs being incurred or led to CCR costs being unreasonably higher than otherwise would have been incurred. The CCR Settling Parties reserve their rights only to propose an adjustment to future CCR costs on the grounds that the costs were otherwise unreasonable or were imprudently incurred.

Thus, the CCR Settling Parties in the CCR Settlement settle the ratemaking treatment of CCR costs in this rate case and future rate cases. The agreement aims to reduce costs that are passed on to customers, to avoid additional protracted litigation over the Companies' historical management practices, and to provide some closure to the debate that has been waged for several years. Indeed, the parties to the Companies' rate cases have extensively litigated these contested issues since at least the filing of the 2018 rate cases, and the CCR Settlement seeks to resolve comprehensively certain issues for CCR costs incurred by DEC from January 1, 2015, through January 31, 2030.

While the CCR Settlement is a nonunanimous settlement, the Commission places significant weight on the fact that the Public Staff and the AGO, each of which has litigated the issues associated with CCR cost recovery vigorously in these cases and advocated zealously for consumers, are parties to the CCR Settlement. Moreover, beginning with the 2018 rate cases, the CCR Settling Parties have advocated for significantly different ratemaking treatment for CCR costs, particularly as to how much cost should be borne by customers versus by the Companies. Thus, the Commission recognizes the extent of the compromise and give-and-take that was necessary to achieve consensus on the ratemaking issues. As noted by Public Staff witness Maness, "among the most important benefits provided by the CCR Settlement Agreement are: (1) the agreement of DEC and DEP to forego recovery of CCR Costs and associated Financing Costs in excess of $900 million (combined DEC and DEP), on a present value basis, over the period from January 1, 2015, through January 31, 2030 (DEC), and February 28, 2030 (DEP), resulting in a significant reduction in the proposed revenue increase in this case; (2) the agreement to allocate any proceeds of CCR insurance litigation; and (3) the avoidance of protracted litigation over CCR and Financing Costs into 2030 among the parties to the Agreement and possibly the appellate courts." Maness Settlement Testimony at 5:10-6:3. For these reasons, the Public Staff concluded that the CCR Settlement is in the public interest. Similarly, as noted by Company witness De May, the settlement "represents a balanced solution" that provides both immediate and long-term savings for customers while providing the certainty the Company requires to meet its business needs. Further, witness De May explained that the settlement allows the Company and the CCR Settling Parties to put the debate behind them and move forward to focus on a cleaner energy future. De May Settlement Testimony at 3:8-16. For these reasons, the Company concluded that the CCR Settlement is in the public interest.

CUCA is the one party to the proceeding that presented evidence regarding DEC's CCR costs but did not join the CCR Settlement.[4] CUCA witness O'Donnell testified that the North Carolina legislature passed CAMA in 2014 in response to the Dan River spill and that CAMA is more stringent than the CCR Rule. He recommended that DEC not be allowed to recover CCR costs associated with any plant that is not subject to the CCR Rule but that is subject to CAMA. He further recommended that to the extent any site is no longer receiving coal ash, remediation costs should not be paid for by ratepayers in this case or any future cases. CUCA's position was refuted by the Company in this case. In addition, CUCA's position was previously rejected by the Commission in the DEC

[4] The Commission notes that CUCA is indicated as "not objecting" to the CCR Settlement and did not request an opportunity to present additional evidence on the CCR Settlement or cross-examine the witnesses of the Company or the Public Staff on the CCR Settlement. Joint Motion to Reopen Record, Consolidate Consideration of CCR Settlement Agreement, and for Approval of CCR Settlement Agreement, January 29, 2021.

2018 Rate Order. It was similarly raised by CUCA, refuted by the Company, and rejected by the Commission in DEP's 2018 rate case. These Commission determinations were upheld by the North Carolina Supreme Court in *Stein*. As was the case in the 2018 proceeding, CUCA witness O'Donnell did not quantify any amount that should not be recovered based on the contention that CAMA was enacted in response to the Dan River spill or that CAMA has resulted in the Company's incurring identifiable incremental costs. Rather, he testified simply that consumers should not pay for all of the Company's costs incurred and that the costs should be split equally among the Company and its customers, similar to the recommendation of the Public Staff. However, the Commission notes that the Commission's adoption of the CCR Settlement provides CUCA with its requested relief of a sharing of CCR costs.

In its Order Declining to Adopt Proposed Settlement Rules, the Commission emphasized that "settlements should be encouraged, and that the Commission should do all it lawfully and reasonably can to facilitate the parties' efforts to reach a full and fair settlement." *Rulemaking Proceeding to Consider Proposed Rule Establishing Procedures for Settlements and Stipulated Agreements*, No. M-100, Sub 145, at 10 (N.C.U.C. Mar. 1, 2017). In the instant proceeding, after years of litigation before this body and the courts, the CCR Settling Parties have worked to achieve a settlement of their views and what they perceive to be a full and fair resolution of their disparate positions. In recognition of the foregoing and in light of the evidence in the record, the Commission is persuaded that the compromise embodied in the CCR Settlement is in the public interest. The CCR Settlement appropriately resolves the issues involving the ratemaking treatment of the costs incurred in connection with DEC's management, handling, and remediation of CCRs, including the financing costs incurred while those costs are deferred and while they are being recovered. In addition, the CCR Settlement provides benefits to customers, including a significant reduction in the amount of costs to be recovered by the Company, certainty as to the application of insurance proceeds for customers' benefit, and the avoidance of protracted and expensive litigation regarding the Companies' historical handling of CCRs. The CCR Settlement, which provides significant savings to customers in the near term, also appropriately balances the need for rate relief with the impact of such rate relief on customers in light of the current economic conditions faced by customers due to the COVID-19 pandemic.

At the four public witness hearings conducted by the Commission in this proceeding, a majority of the public witnesses who testified before the Commission expressed concerns regarding the costs and impacts of coal-fired electricity generation. At those hearings, the Commissioners heard first-hand the many perspectives and opinions of customers as to the clean-up of coal ash and the associated costs. Specifically, the following witnesses provided testimony expressing that customers should not bear responsibility for paying for the clean-up of CCRs: (1) in Franklin eight out of the 10 public witnesses, including Estes, Enstrom, Bailey, Bernard, Thomas, Zwinak, Breckheimer, and Uccetta; (2) in Morganton, two out of the five public witnesses, including Wasson, Deal; (3) in Graham 12 out of the 25 public witnesses, including Armijo, Graham, Phillips, Jones, Sanchez, Velez, Cassebaum, Voss, Clapp, Wagner, Smith, Alston; and (4) in Charlotte, 18 out of the 30 public witnesses, including Rose, K. Kneidel, Walsh, S. Kneidel, Henry, Adams, Wells, Goff, Backman, Richardson, Fox, Blanco, De Mallie, Menut, Sparrow, Arevalo, Swaim, Lewin. Tr. vol. 1, 14-25, 28-32, 35-38; tr. vol. 2, 30-35; tr. vol. 3, 17-29, 36-39, 43-48, 51-53, 65-66, 71-73, 78-82, 88-92; tr. vol. 4, 18-20, 24-36, 42-44, 53-57, 62-71, 78-80, 83-94. In addition, those who wrote to express concern emphasized many of the same perspectives. Of the hundreds of statements of consumer position filed in the docket, a majority expressed that customers should not bear responsibility for costs associated with the clean-up of coal ash. *See generally*, Docket No. E-7, Sub 1214CS. Thus, based on the perspectives and concerns consistently expressed by witnesses at the public hearings and in the statements of consumer position filed in the docket, the Commission concludes that the history and legacy of coal-fired electricity generation by the Company is an issue of significant importance to its customers, and their perspectives must be given weight in the Commission's decision-making process. While the CCR Settlement may not go as far as many customers advocated, it strikes a fair balance for customers that the Commission determines will reduce costs (and rates) associated with CCRs, particularly in the near term, and furthers the Company's financial health and access to capital at a reasonable cost.

For these reasons, the Commission concludes that the CCR Settlement is in the public interest and should be approved. Moreover, the Commission concludes that the ratemaking treatment of CCR costs set forth in the CCR Settlement, in conjunction with the other decisions contained within this Order, results in just and reasonable rates for DEC's customers.

Finally, the Commission asked a number of questions at the hearing in this case, including requests for late-filed exhibits analyzing the issue, regarding the possibility of recovering future CCR costs contemporaneously with the expense as an alternative to deferral and amortization, as proposed by the Company in its previous rate case. The Commission notes that the CCR Settlement does not involve such a cost recovery mechanism, opting instead to follow the "spend-defer-recover" method. In accepting and adopting the CCR Settlement, the Commission is not deciding that a cost recovery mechanism that would allow the Company to recover contemporaneously as costs are incurred is without merit. Rather, given the greater certainty that exists with respect to annual costs to be incurred, the Commission sees merit in such an approach, particularly if structured to result in savings to customers. The Commission directs the Company to consider the proper extent to which a contemporaneous cost recovery mechanism could be joined with the "spend-defer-recover" method prior to the next general rate case.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 27–29

ARO Accounting

The evidence supporting these findings of fact is found in the verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

There has been substantial discussion devoted to the subject of "ARO accounting" in the current proceeding as well as prior DEC proceedings. The Commission will not discuss in detail here the testimony presented by the various parties but will summarize the pertinent facts.

In June 2001 the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards 143, Accounting for Asset Retirement Obligations (SFAS 143), which addressed financial accounting and reporting requirements associated with an entity's legal requirement to retire a long-lived asset. Specifically, SFAS 143 required an entity to recognize the fair value of a liability for an asset retirement obligation (ARO) in the period in which it is incurred if a reasonable estimate of the fair value can be determined. Additionally, upon initial recognition of a liability for an ARO, an entity was required to capitalize an asset retirement cost (ARC) by increasing the carrying amount of the related long-lived asset by the same amount as the liability. This standard was later codified as Accounting Standards Codification 410, Asset Retirement and Environmental Obligations (ASC 410).

In response to the issuance of SFAS 143, on October 30, 2002, the FERC issued a Notice of Proposed Rulemaking to revise the USOA so that FERC accounting requirements would be consistent with those used by FERC-regulated entities for financial reporting purposes. On April 9, 2003, the FERC issued an order amending the USOA. *Accounting, Financial Reporting, and Rate Filing Requirements for Asset Retirement Obligations*, Order No. 631, 103 FERC ¶ 61,021, *reh'g denied*, Order No. 631-A, 104 FERC ¶ 61,183 (2003). Specifically, FERC added new balance sheet and income statement accounts. The FERC ruled that no FERC-regulated entity with formula rate tariffs could include ARO costs in its billing determinations without prior approval. As a FERC-regulated entity, DEC must comply with the USOA. In addition, Commission Rule R8-27 states that the Commission has adopted the FERC USOA as the accounting rules applicable to electric utilities under its jurisdiction subject to certain exceptions and conditions. One such exception is that electric utilities under the jurisdiction of this Commission are required to seek approval to record any items in FERC Account 182.3 – Other Regulatory Assets.

On January 10, 2003, in response to FASB's issuance of SFAS 143, DEC filed a petition in Docket No. E-7, Sub 723 for authority to place certain ARO costs in a deferred account. A request for deferral accounting was necessary so that adoption of SFAS 143 would have "no impact on [DEC's] operating results or return on rate base for North Carolina retail regulatory purposes" such that DEC's "North Carolina retail rate base, net operating income, and regulatory return on common equity" would be the same as they would have been absent the implementation of SFAS 143. Order Granting Motion for Reconsideration and Allowing Deferral of Costs, *Petition for Authority to Place Certain Asset Retirement Obligation Costs in a Deferred Account*, No. E-7, Sub 723, at 11-12 (N.C.U.C. Aug. 8, 2003) (Sub 723 Order).

In its Sub 723 Order the Commission required DEC to make a filing setting forth the journal entries it recorded when initially implementing SFAS 143. Further, DEC was required to file annual reports reconciling the account balances in the Company's annual report filed pursuant to Commission Rule R1-32 and the annual North Carolina retail cost-of-service studies filed with the Commission.

On February 18, 2004, DEC filed the required journal entries. As shown therein, at the time of implementation of SFAS 143 the only ARO recorded by DEC was for decommissioning of its nuclear plants. A review of subsequent reconciliation reports shows that it was not until DEC filed its reconciliation report for 2014, after the enactment of CAMA, that there was a significant ARO recorded for steam plant. After the enactment of the CCR Rule, the report for 2015 showed another significant increase in the ARO for steam plant.

DEC's Chief Financial Officer, Brian Savoy, wrote a letter to the Commission dated December 21, 2015 (Savoy Letter), explaining that due to both CAMA and the CCR Rule, the ARO recorded on DEC's books as of November 30, 2015, was approximately $1.84 billion but noted that actual costs to comply with CAMA and the CCR Rule could be materially different. The Company stated that it was not seeking further specific accounting approval at that time but was simply providing an explanation of its accounting for ash basin closure and compliance costs for the Commission's information. DEC stated that only actual costs resulting in cash outlays by the Company related to ash basin closure, plus carrying charges, would result in amounts the Company would seek accounting and rate treatment for in future filings. In the current proceeding, DEC witness Riley explained this concept when he testified that ARO assets and liabilities are presented on a company's balance sheet as a result of accounting journal entries, not from investor or customer contributions, and therefore are not considered for ratemaking purposes until actual costs are expended. Tr. vol. 23, 131.

DEC made such a petition for an accounting order on December 30, 2016, in Docket No. E-7, Sub 1110. In that filing DEC requested approval to defer, in a regulatory asset, costs incurred after January 1, 2015, to comply with federal and state regulations and a return on those costs at the Company's approved weighted cost of capital until the approval of new rates in the Company's next base rate case. DEC stated that from January 2015 through November 2016 the Company had incurred $434.4 million of expenses for state and federal compliance. On July 10, 2017, the Commission issued an order consolidating DEC's request with its then pending general rate case proceeding, Sub 1146.

Prior to seeking rate recovery, the Company's requests and the Commission's decisions were simply intended to ensure that DEC complied with GAAP and FERC accounting requirements but that such compliance did not impact North Carolina retail ratemaking. When DEC requested rate recovery of deferred ash basin closure costs, the issue before the Commission was no longer one of accounting but rather one of ratemaking.

The approval by the Commission of a five-year amortization period for deferred costs in Sub 1146 did not change the Company's requirement to comply with GAAP and FERC. The Company must still record AROs and ARCs; however, for financial reporting purposes those amounts will be adjusted for amounts approved for recovery in rates. This is shown on DEC Late Filed Exhibit 6 where the amount recorded in Account 182.3 – Regulatory Assets "theory" will be transferred to Account 182.3 – Regulatory Assets "spend." The same accounting was set forth in Public Staff Late Filed Exhibit 2.

The Commission reiterates that it will not discuss in detail the various testimony surrounding ARO accounting, ARO-related accounting, deferred expenses, or capitalized costs. The nomenclature applied to the costs which DEC has incurred and will continue to incur in order to comply with both CAMA and the CCR Rule is not pertinent to the ratemaking treatment of such costs. The Commission determined in Finding of Fact No. 65 in the 2018 DEC Rate Order that the Company's request to defer in a regulatory asset account certain costs incurred in connection with compliance with federal and state environmental requirements was reasonable and appropriate. The Commission also determined in that order that DEC expects to incur substantial costs related to coal ash remediation in future years, that it was just and reasonable to allow deferral of those costs, and that the ratemaking treatment of those costs would be addressed in future rate proceedings. The instant proceeding is such a proceeding. The only determination required of the Commission in this proceeding, and future general rate case proceedings, is the prudence of the Company's expenditures and the appropriate ratemaking treatment of such prudently incurred costs. These questions are addressed elsewhere in this Order.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 30–35

Capital Structure, Cost of Capital, and Overall Rate of Return

The evidence supporting these findings of fact is found in the verified Application and Form E-1; the stipulations entered into between DEC and several parties; and the testimony and exhibits of DEC witnesses D'Ascendis, Newlin, Young, and Fetter, Public Staff witnesses Woolridge and Hinton, AGO witness Baudino, CBD/AV witness McIlmoil, Commercial Group witness Chriss, CIGFUR witness Phillips, CUCA witness O'Donnell, and Tech Customers witness Strunk; and the entire record in this proceeding.

A. Rate of Return on Equity Capital

Summary of the Evidence

In his direct testimony witness D'Ascendis recommended an ROE of 10.50%; however, in its Application, as a rate mitigation measure, the Company requested approval for its rates to be set using an ROE of 10.30% and an overall rate of return of 7.63%. The Company later stipulated to an ROE of 9.75% in individual settlement agreements with Harris Teeter, the Commercial Group, CIGFUR, Vote Solar, NCSEA, and NCJC et al., which is a decrease from the 9.90% ROE and overall rate of return of 7.35% authorized by the Commission in the Company's last rate case, Sub 1146. Subsequently, the Company and the Public Staff executed the Second Partial Stipulation which provides for an ROE of 9.60%. As a result, the HT Stipulation, CG Stipulation, CIGFUR Stipulation, Vote Solar Stipulation, and NCSEA/NCJC et al. Stipulation were each amended as previously described to provide that if the Commission enters a final order in this docket approving a rate of return of 9.60% to be applied to a common equity component of the ratemaking capital structure consisting of 52% equity and 48% long-term debt, those parties would agree that the provisions of their settlement agreements concerning the ROE and capital structure have been fulfilled.

Witnesses for the Public Staff, CIGFUR, the AGO, Commercial Group, Tech Customers, CUCA, and CBD/AV also filed direct testimony on the appropriate ROE to be established in this rate case. This evidence was followed by the Public Staff First and Second Partial Stipulations and the other intervenor settlements, supplemental testimony of Baudino, rebuttal and supplemental rebuttal testimony filed by witness D'Ascendis, settlement testimony filed by DEC witness D'Ascendis and Public Staff witness Woolridge, and finally testimony of witnesses D'Ascendis, Baudino, McIlmoil, and O'Donnell at the consolidated hearing in this matter.[5] In addition to this expert testimony, the Commission received the testimony of a number of public witnesses on DEC's proposed rate increase, as well as numerous statements of consumer position. All of this evidence is summarized below.

DEC Direct Testimony

Company witness D'Ascendis recommended in his direct testimony an ROE of 10.50%, which was the midpoint of his recommended range of 10.00% to 11.00%. Tr. vol. 11, 47. Witness D'Ascendis stated that the ROE, or the cost of equity, is the return that investors require to make an equity investment in a firm. That is, investors will provide funds to a firm only if the return that they *expect* is equal to, or greater than, the return that they *require* to accept the risk of providing funds to the firm. From the firm's perspective, that required return represents the cost of equity capital. Witness D'Ascendis testified the cost of equity is neither directly observable nor a contractual obligation. Rather, equity investors have a claim on cash flows only after debt holders are paid; the uncertainty (or risk) associated with those residual cash flows determines the cost of equity. Since the cost of equity cannot be directly observed, it must be estimated or inferred based on market data and various financial models. Witness D'Ascendis testified that each of those models is subject to specific assumptions, which may be more or less applicable under differing market conditions. *Id.* at 58-59.

Witness D'Ascendis noted that as all financial models are subject to various assumptions and constraints, equity analysts and investors tend to use multiple methods to develop their return requirements. *Id.* at 48. He therefore relied on three widely accepted approaches to develop his rate of return on common equity determination: (1) the Constant Growth and Multi-Stage forms of the Discounted Cash Flow (DCF) model, (2) the Capital Asset Pricing Model (CAPM), and (3) the Bond Yield Plus Risk Premium approach. *Id.* He noted, however, weaknesses in the Constant Growth DCF Model, namely that those results are far removed from the returns recently authorized in other jurisdictions and fail to adequately reflect evolving capital market conditions and he therefore discounted those results. *Id.* at 49. The Constant Growth DCF Model produced ROE results ranging from a low of 8.86% to a high of 9.96%, and the Risk Premium-based results, including the CAPM, Empirical CAPM, and Bond Yield Plus Risk Premium methods produced results ranging from a low of 8.68% to a high of 11.10% in connection with one variant of the Empirical CAPM. *Id.* at 56. Finally, the Expected Earnings analysis, which is used to assess the reasonableness of the DCF, CAPM, and Bond-Yield Plus

[5] Tech Customers witness Strunk appeared at the hearing but did not directly address the issue of ROE.

Risk Premium results, produced an ROE estimate with a mean of 10.44% and median of 10.54%. *Id.* at 57. Witness D'Ascendis noted that the FERC uses the Expected Earnings analysis to determine the "zone of reasonableness." Tr. vol. 11, 26.

Witness D'Ascendis provided extensive testimony concerning the capital market environment, *id.* at 107-16, and addressed the effect those market conditions have on the return investors require in order to commit their capital to equity securities. Witness D'Ascendis also focused on capital market conditions as they affect the Company's customers in North Carolina. *Id.* at 97-107. Specifically, his analysis found that the North Carolina and national economies continue to be highly correlated with one another. He concluded therefore that North Carolina conditions "continue to be reflected in the models and data used to estimate the Cost of Equity." *Id.* at 99.

In addition to his econometric models and evaluation of capital market risks, witness D'Ascendis also considered Company-specific business risks in arriving at his final ROE recommendation. These include (1) the risks associated with certain aspects of the Company's generation portfolio, and (2) the Company's significant capital expenditure plan. *Id.* at 81-82.

Regarding economic conditions in North Carolina, witness D'Ascendis noted that North Carolina and the counties comprising DEC's service territory "continue to steadily emerge from the economic downturn that prevailed during 2009-2010 and have experienced significant economic improvement during the last several years." Tr. vol. 11, 106.

Public Staff Direct Testimony

Public Staff witness Woolridge performed DCF and CAPM analyses for both his and witness D'Ascendis' proxy groups of electric utilities. Witness Woolridge developed his DCF growth rate after reviewing 13 growth rate measures, including historic and projected growth rate measures, and evaluating growth in dividends, book value, earnings per share (EPS), and growth rate forecasts from Yahoo, Reuters, and Zack's. Tr. vol. 17, 93, 135. Witness Woolridge applied the DCF model and CAPM which yielded the following results:

- Discounted Cash Flow (DCF) – Electric Proxy Group
  - 8.25% Equity Cost Rate
- DCF – D'Ascendis Proxy Group
  - 8.4% Equity cost rate
- CAPM – Electric Proxy Group and D'Ascendis Proxy Group
  - 6.9% Equity Cost Rate

Id. at 161.

In witness Woolridge's CAPM analysis, he used for the risk-free interest rate the top end of the range of yields on 30-year U.S. Treasury bonds over the 2013-2020 time period, 3.75%. *Id.* at 147. He used the Value Line Investment Survey betas of 0.55 for both his and witness D'Ascendis' proxy groups. *Id.* at 149. Witness Woolridge's market risk premium was 5.75%, which gave most weight to the market premium estimates of KPMG, CFO Survey, Duff & Phelps, the Fernandez survey, and Damodaran. He testified that his 5.75% value is a conservatively high estimate of the market risk premium. *Id.* at 160.

Witness Woolridge concluded that the appropriate equity cost rate for companies in his and witness D'Ascendis' proxy groups is in the 6.90% to 8.40% range. *Id.* at 162. However, witness Woolridge took into account the fact that his range was below the authorized ROEs for electric utilities nationally and made a primary recommendation of a 9.00% ROE, assuming a 50% common equity ratio. Witness Woolridge also provided an alternative recommendation of an 8.40% ROE based on the Company's originally requested capital structure of 53% equity and 47% debt. *Id.* at 219.

Witness Woolridge did not perform an ECAPM analysis. He testified that the ECAPM is an ad hoc version of the CAPM. *Id.* at 180.

Witness Woolridge also testified as to current capital market conditions as of the date of his testimony in February 2020. He stated that although the Federal Reserve increased the Federal Funds rate between 2015 and 2018, interest rates and capital costs remain at low levels. Witness Woolridge also pointed out that in 2019 interest rates fell dramatically with moderate economic growth and low inflation, while the Federal Reserve cut the federal fund rate in July, September, and October and the 30-year yield traded at all-time low levels. *Id.* at 91.

Witness Woolridge responded to witness D'Ascendis' assessment of the economic conditions in North Carolina. He generally agreed with witness D'Ascendis' general conclusion that economic conditions in North Carolina have improved since the Company's last rate case. Witness Woolridge stated that "[a]s highlighted by the correlations between U.S. and North Carolina economic data . . . economic conditions have improved with the overall economy over the past decade." Tr. vol. 17, 211. He argued, however, that although economic conditions generally have improved, other conditions such as the higher unemployment rate in the DEC service territory and the state compared to the United States, a median household income in North Carolina that is lower than the national figure, and the greater than 100 basis point difference in DEC's requested ROE and the average authorized ROEs for electric utilities in 2018-2019, do not support the Company's proposed ROE. *Id.* at 96. Specifically, he noted that while the unemployment rates in North Carolina and DEC's service territory have fallen by two-thirds since their peaks in the 2009–2010 period, they are both above the national average of 3.90%, and that while North Carolina's residential electric rates are below the national average, the median household income is more than 10% below the U.S. norm. *Id.*

AGO Direct and Supplemental Testimony

AGO witness Baudino proposed an ROE of 9.00% based on a capital structure comprising 51.50% equity and 48.50% long-term debt. Witness Baudino's recommendation was based upon his DCF-based market approaches along with the CAPM approach. Tr. vol. 16, 318-19. Witness Baudino later provided supplemental direct testimony where he updated interest rates and market data "since the beginning of March 2020, when concerns about the COVID-19 pandemic began to roil financial markets with extreme volatility." *Id.* at 382. Witness Baudino testified regarding the recent volatility in the markets, including "sharp increase in betas for the companies in the proxy group" *Id.* at 391) resulting in a higher DCF ranging from 8.29 to 9.28, an increase from his initial DCF range of 8.21 to 9.02. *Id.* at 390, Tr. vol. 2, 128. Likewise, witness Baudino testified that nationally, the real gross domestic product (GDP) "declined in the first quarter of 2020 by -5.0%, according to the Bureau of Economic Analysis." Tr. vol. 16, 394. Nevertheless, he continued to recommend a 9.00% ROE in his supplemental direct testimony.

In his direct testimony witness Baudino testified that his 9.00% ROE recommendation was "reasonably close to recently allowed ROEs." Tr. vol. 16, 352. As a reference point to determine "reasonably close" he relied upon average public utility commission allowed ROEs during 2016, 2017, 2018, and 2019 Tr. vol. 2, 135-37) which he calculated as 9.60%, 9.68%, 9.56%, and 9.57%, respectively. Tr. vol. 16, 351.

CUCA Direct Testimony

Witness O'Donnell proposed an ROE of 8.75%, primarily based upon DCF modeling and CAPM methodologies, as well utilizing a comparable earnings approach. Tr. vol. 20, 135-36. Witness O'Donnell's DCF analysis results ranged from 7.0% to 10.0% with a midpoint of 8.50%, his CAPM analysis ranged from 5.0% to 7.0% with a midpoint of 6.50%, and his comparable earnings analysis ranged from 9.25% to 10.25% with a midpoint of 9.75%. *Id.* at 136. He believed that the midpoint of his DCF was the most accurate representation of market conditions as supported by his CAPM analysis but chose a return in the upper end of his DCF range based on allowed returns from other jurisdictions. *Id.*

Commercial Group Direct Testimony

While he did not provide an ROE analysis in his testimony, witness Chriss for the Commercial Group testified that the Company's proposed ROE was significantly higher than rates previously approved by the Commission from 2016 to present, including the prior rate case in 2017. Tr. vol. 16, 69. Likewise, witness Chriss indicated that the Company's proposed ROE is significantly higher than most reported ROE decisions by utilities commissions from 2016 to the present. *Id.* at 70-71. He testified that according to S&P Global Market Intelligence, 148 decisions were rendered over that time frame, with results ranging from 8.43% to 11.95%, and the median authorized ROE was 9.60%. *Id.* at 70. Removing distribution-only utilities and distribution service rates from the analysis, he testified that the average ROE for vertically integrated utilities authorized from 2016 through the time of his direct testimony filing was 9.75%, and the trend in these averages has been relatively stable. *Id.* at 70-71. As previously noted, the Commercial Group subsequently entered into a settlement agreement wherein the parties agreed to a 9.75% ROE that was subsequently amended to provide that if the Commission authorized a 9.60% ROE, the parties agree that the provisions of their agreement on the ROE and capital structure shall have been fulfilled.

CIGFUR Direct Testimony

CIGFUR witness Phillips testified that DEC's requested ROE of 10.30% is unreasonable and should be rejected. Tr. vol. 22, 97. He presented evidence that the national average authorized ROE for vertically integrated electric utilities is currently 9.73%. *Id.* He recommended that a reasonable ROE for DEC should not exceed the current national average for vertically integrated electric utilities. *Id.* Similar to the Commercial Group, CIGFUR subsequently entered into a settlement agreement where the parties agreed to a 9.75% ROE that was subsequently amended to provide that if the Commission authorized a 9.60% ROE, CIGFUR would agree that the provisions of its agreement on ROE and capital structure shall have been fulfilled.

CBD/AV Direct Testimony

CBD/AV witness McIlmoil recommended an ROE of "no greater than 9.2 percent" based on a 52/48 capital structure, as approved for Dominion Energy Virginia by the Virginia State Corporation Commission (VSCC) in November 2019. Tr. vol. 16, 587. He recommended that the Commission make consideration of customers' energy burden a priority factor in determining an allowed ROE. *Id.* At the hearing in his summary, witness McIlmoil lowered his recommended ROE to 9.00%. Tr. vol. 10, 125.

Tech Customers Direct Testimony

Tech Customers witness Strunk recommended a lower allowed ROE in line with lower-risk utilities. *Id.* at 145. He opined that witness D'Ascendis' recommendation of 10.50% evidenced witness D'Ascendis' inflation of the ROE. *Id.* at 137. Similarly, witness Strunk testified that witness D'Ascendis' proposed ROE is at the top of the range of allowed returns for other vertically integrated utilities. *Id.* at 139. Witness Strunk likewise asserted that witness D'Ascendis assigned a higher risk to the Company than that of his proxy group. *Id.* at 138.

DEC Rebuttal Testimony

Witness D'Ascendis responded to and discussed in detail the intervenor witnesses' criticisms of his ROE conclusions and recommendations. He indicated that "none of their arguments caused me to revise my conclusions or recommendations." Tr. vol. 1, 46. Witness D'Ascendis stated that "financial models are important tools in determining returns and appreciate[s] that because all models are subject to assumptions, no one method is most reliable at all times, and under all conditions," and therefore it "remains critically important to apply reasoned judgment to determine where the Cost of Equity falls within that model's range of results." Tr. vol. 11, 151.

Generally, witness D'Ascendis advised that over the last five years nearly all authorized ROEs for vertically integrated electric utilities have been above the intervenor witnesses' recommendations. *Id.* at 149. Witness D'Ascendis also included as Chart 1 of his rebuttal testimony a comparison of authorized ROEs for other vertically integrated utilities from 2015 through 2020 that he testified shows that the intervenor witness recommendations are far below the ROEs available to other such utilities.[6] Tr. vol. 11, 150.

Witness D'Ascendis indicated that the "significant departure" represented by the recommendations of witnesses Baudino, O'Donnell, and McIlmoil raises two concerns. First, DEC must compete with other companies, including utilities, for long-term capital needed to provide safe and reliable utility service, and such competition means that the Company would be at a disadvantage in the capital markets if the Commission were to approve an ROE in the ranges recommended by witnesses Baudino, O'Donnell, and McIlmoil. As a result, he testified a likely outcome would be increasing reluctance on the part of investors to provide capital at reasonable costs and terms. Witness D'Ascendis also noted that while they are not exclusively relied upon, authorized ROEs provide observable and measurable benchmarks against which return recommendations may be assessed. *Id.* at 150-51)

Witness D'Ascendis challenged witness O'Donnell's application of the Constant Growth DCF and subsequent recommendation for an ROE of 8.75%. *Id.* at 292. Witness D'Ascendis explained that the reliance on historical growth rates by witnesses O'Donnell and Baudino as part of their Constant Growth DCF modeling does not adequately encapsulate how the model is a forward-looking measure of investors' expectations and there is support that future growth is superior to that of historically oriented growth measures. In response to Witness O'Donnell's contention that the DCF approach is "far superior to all the models now used by practitioners" Consolidated Tr. vol. 3, 26, witness D'Ascendis contended that no support was offered for that assertion. In response to witness O'Donnell's use of the Retention Growth Model, witness D'Ascendis tested the relationship between retention ratios and future growth rates and demonstrated that earnings growth actually *decreased* as the retention ratio increased. Tr. vol. 11, 301. Witness D'Ascendis testified that the CAPM addresses comparable risk in a way that the DCF-based methods do not; the Beta coefficient reflects "systematic" risk which provides a direct measure of relative risk. *Id.* at 311.

Regarding witness McIlmoil's recommended ROE, witness D'Ascendis noted that this was an ROE approved for Dominion Energy Virginia by the VSCC in November 2019, which was a Rate Adjustment Clause hearing and not a general rate case. *Id.* at 337. Moreover, witness D'Ascendis noted that witness McIlmoil failed to acknowledge that the framework in Virginia also includes an earning sharing mechanism of a 70-basis point dead band around the 9.2% ROE. *Id.* at 338. Witness D'Ascendis testified that the current authorized ROE for Dominion Energy Virginia's general rate base assets is 10.00%, and this Commission recently authorized a 9.75% ROE for Dominion's North Carolina operations. *Id.* at 337-38.

Additionally, witness D'Ascendis testified that the intervenor witnesses fail to recognize the risks faced by the Company, and their recommended ROEs do not appropriately reflect the evolving capital market environment. *Id.* at 148. To illustrate his

[6] The chart prepared by witness D'Ascendis reflects witness Woolridge's original 9.00% ROE recommendation.

point that an ROE in the range recommended by Baudino, O'Donnell, and McIlmoil would risk devaluing the Company's equity and, thus, ability to compete for capital, witness D'Ascendis provided an example of a recent rate decision for CenterPoint Energy Houston Electric in which the financial community responded negatively to an adverse regulatory outcome. *Id.* at 153.

Witness D'Ascendis also provided supplemental rebuttal testimony to update his ROE models and respond to the supplemental direct testimony of AGO witness Baudino regarding current and expected capital markets and their effect on the cost of equity.

Witness D'Ascendis testified that as a result of the COVID-19 pandemic, economic conditions deteriorated in North Carolina in the first half of 2020, as have economic conditions across the country. Tr. vol. 11, 374. Witness. D'Ascendis noted that even though the North Carolina and U.S. economies have contracted, economic conditions in North Carolina continue to be highly correlated to conditions nationally and therefore continue to be reflected in the analyses used to determine the ROE. Tr. vol. 11, 364. In addition, witness D'Ascendis testified that the current level of volatility, which is 50% higher than normal levels, is expected to persist until at least the end of 2021. *Id.* at 362.

Witness D'Ascendis addressed several of the conclusions in witness Baudino's supplemental testimony having to do with how the market upheaval had led to lower Treasury and utility bond yields and higher beta coefficients, and utility companies' stability of operations and credit metrics in response to the turmoil. *Id.* at 347. He responded to each and concluded that none of witness Baudino's arguments resulted in a revision of witness D'Ascendis' conclusions or recommendations. He further concluded that the market turmoil left risk higher than it had been previously and testified that the change must be reflected in the investor-required return. *Id.* at 362-63.

Witness D'Ascendis updated his ROE analyses based on market data as of June 30, 2020, resulting in a DCF ranging from 7.76% - 9.67%, a CAPM ranging from 10.19% - 15.70%, an ECAPM ranging from 10.94% - 15.70%, a Bond Yield Risk Premium ranging between 9.96% - 10.25%, and an Expected Earnings ranging between 5.5% - 13.5%. *Id.* at 344-45, D'Ascendis Supplemental Exs.1-6.

Stipulations

As discussed above, in separate stipulations with CIGFUR, Commercial Group, and Harris Teeter, the Company stipulated to an ROE of 9.75%, along with a number of other provisions representing substantial give and take between the parties. Subsequently, the Company and the Public Staff executed the Second Partial Stipulation, which among other things, provided for an ROE of 9.60%. Thereafter, the other intervenor settlements were amended to provide that if the Commission enters a final order in this docket approving a rate of return of 9.60% to be applied to a common equity component of the ratemaking capital structure consisting of 52% equity and 48% long-term debt, those parties would agree that the provisions of their settlement agreements concerning the ROE and capital structure have been fulfilled.

DEC Settlement Testimony

Witness D'Ascendis provided settlement supporting testimony, in which he supported the Second Partial Stipulation reached between the Public Staff and the Company, explaining that though the stipulated ROE of 9.60% is somewhat below his recommended range, he recognizes that the settlement represents negotiation by the parties of otherwise contested issues and that the Company believes that the Second Partial Stipulation's ROE and capital structure "would be viewed by the rating agencies as constructive and equitable." Tr. vol.11, 368-69. He noted that since 2016 the average authorized ROE for vertically integrated electric utilities has been 9.74%, and that among jurisdictions like North Carolina that are as seen as having constructive regulatory environments, the average authorized ROE was 9.91%. *Id.* at 370-72. Witness D'Ascendis also testified that economic conditions in North Carolina, which deteriorated in the first half of 2020, remain highly correlated to the overall conditions nationwide. *Id.* at 374. He noted that while the 9.60% stipulated ROE "is somewhat below the lower bound of my recommended range," *id.* at 368, as discussed throughout his other testimony "capital market conditions became quite volatile as a result of the COVID-19 pandemic" and as a consequence, "the models used to estimate the Cost of Equity produce a wide range of estimates." *Id.* at 369. Witness D'Ascendis noted, "From January 2016 to June 2020, the average authorized ROE for vertically integrated electric utilities was 9.74%, 14 basis points above the Stipulated ROE. Of the 107 cases decided during that period, 64 (*i.e.*, nearly 60%) included authorized returns of 9.60% or higher." *Id.* at 370. He concluded that the 9.60% stipulated ROE is "a reasonable resolution of an otherwise contentious issue." *Id.*

Public Staff Settlement Testimony

In his testimony supporting the Second Partial Stipulation, Public Staff witness Woolridge testified that he found the cost of capital components reasonable within the context of the overall settlements and in resolution of most of the issues in the proceeding. Tr. vol. 17, 225-28. He noted that the stipulated ROE was a compromise for each party, a reduction from the Company's last authorized ROE of 9.90%, below the 9.67% average authorized ROE for vertically integrated electric utilities during the first half of 2020, and the lowest ROE authorized for a vertically integrated investor-owned electric utility in North Carolina in at least the last 30 years. *Id.* at 229-30.

Hearing Testimony

Under cross-examination by the AGO, witness D'Ascendis noted that measures of volatility had fallen since March but remained high and were expected to continue to remain high. Consolidated Tr. vol. 2, 43-44. Witness D'Ascendis further testified that the North Carolina economy's response to the pandemic was highly correlated with that of the country but that the effect had been somewhat less severe and the recovery had been somewhat more rapid. He concluded that North Carolina was somewhat less affected by the recession than the nation as a whole. Consolidated Tr. vol. 1, 125-26.

Public Witness Testimony and Consumer Statements of Position

The Commission also received hundreds of consumer statements of position in this docket, many of which expressed concern about DEC's proposed rate increase. The Commission held four hearings throughout the Company's North Carolina service territory in order to receive testimony from the Company's customers. A total of 71 individuals testified and at least 60 were DEC retail customers, almost 20 of whom testified that the rate increase was not affordable for many customers, including those on fixed incomes, the elderly, people with disabilities, the unemployed and underemployed, and the poor.

Law Governing the Commission's Decision on ROE

The ROE is often one of the most contentious issues to be addressed in a rate case, even in a case such as this one in which the Second Partial Stipulation and the other intervenor settlements have been reached. In the absence of a settlement agreed to by all the parties, the law of North Carolina requires the Commission to exercise its independent judgment and arrive at its own independent conclusion as to the proper ROW. *See, e.g., CUCA I,* 348 N.C. at 466, 500 S.E.2d at 707. In order to reach an appropriate independent conclusion regarding the ROE, the Commission must evaluate the available evidence, particularly that presented by conflicting expert witnesses. *State ex rel. Utils. Comm'n v. Cooper*, 366 N.C. 484, 491-93, 739 S.E.2d 541, 546-47 (2013) (*Cooper I*).

The baseline for establishment of an appropriate ROE are the constitutional constraints established by the decisions of the United States Supreme Court in *Bluefield Water Works & Improvement Co. v. Public Service Commission,* 262 U.S. 679 (1923) (*Bluefield*), and *Federal Power Commission v. Hope Natural Gas Co.,* 320 U.S. 591 (1944) (*Hope*), which establish:

> To fix rates that do not allow a utility to recover its costs, including the cost of equity capital, would be an unconstitutional taking. In assessing the impact of changing economic conditions on customers in setting [an ROE], the Commission must still provide the public utility with the opportunity, by sound management, to (1) produce a fair profit for its shareholders, in view of current economic conditions, (2) maintain its facilities and service, and (3) compete in the marketplace for capital.

2018 DEC Rate Order at 50; s*ee also, State ex rel. Utils. Comm'n v. Gen. Tel. Co.*, 281 N.C. 318, 370, 189 S.E.2d 705, 738 (1972) (*General Telephone*). As the North Carolina Supreme Court held in *General Telephone*, these factors constitute "the test of a fair rate of return declared" in *Bluefield* and *Hope*. *Id.*

The ROE is, in fact, a cost. The return that equity investors require represents the cost to the utility of equity capital:

> [T]he cost of capital to the utility is synonymous with the investor's return, and the cost of capital is the earnings which must be generated by the

> investment of that capital in order to pay its price, that is, in order to meet the investor's required rate of return.

Morin, Roger A., *Utilities' Cost of Capital* 19-21 (Public Utilities Reports, Inc. 1984). "The term 'cost of capital' may [also] be defined as the annual percentage that a utility must receive to maintain its credit, to pay a return to the owners of the enterprise, and to ensure the attraction of capital in amounts adequate to meet future needs." Phillips, Charles F., Jr., *The Regulation of Public Utilities* (Public Utilities Reports, Inc. 1993), at 388.

Long-standing decisions of the North Carolina Supreme Court have recognized that the Commission's subjective judgment is a necessary part of determining the authorized ROE. *State ex rel. Utils Comm'n v. Public Staff-N.C. Utils. Comm'n,* 323 N.C. 481, 490, 374 S.E.2d 361, 369 (1988) (*Public Staff*). Likewise, the Commission has observed as much in exercising its duty to determine the ROE, noting that such determination is not made by application of any one simple mathematical formula:

> Throughout all of its decisions, the [United States] Supreme Court has formulated no specific rules for determining a fair rate of return, but it has enumerated a number of guidelines. The Court has made it clear that confiscation of property must be avoided, that no one rate can be considered fair at all times and that regulation does not guarantee a fair return. The Court also has consistently stated that a necessary prerequisite for profitable operations is efficient and economical management. Beyond this is a list of several factors the commissions are supposed to consider in making their decisions, but no weights have been assigned.
>
> The relevant economic criteria enunciated by the Court are three: financial integrity, capital attraction and comparable earnings. Stated another way, the rate of return allowed a public utility should be high enough: (1) to maintain the financial integrity of the enterprise, (2) to enable the utility to attract the new capital it needs to serve the public, and (3) to provide a return on common equity that is commensurate with returns on investments in other enterprises of corresponding risk. These three economic criteria are interrelated and have been used widely for many years by regulatory commissions throughout the country in determining the rate of return allowed public utilities.
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> In reality, the concept of a fair rate of return represents a "zone of reasonableness." As explained by the Pennsylvania commission:
>
>> There is a range of reasonableness within which earnings may properly fluctuate and still be

> > deemed just and reasonable and not excessive or extortionate. It is bounded at one level by investor interest against confiscation and the need for averting any threat to the security for the capital embarked upon the enterprise. At the other level it is bounded by consumer interest against excessive and unreasonable charges for service.
>
> As long as the allowed return falls within this zone, therefore, it is just and reasonable. . . . It is the task of the commissions to translate these generalizations into quantitative terms.

Charles F. Phillips, Jr., *The Regulation of Public Utilities,* 3d ed. 1993, 381-82. (Notes omitted.)

Order Granting General Rate Increase, *Application of Carolina Power & Light Co., d/b/a Progress Energy Carolinas, Inc., for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, No. E-2, Sub 1023, at 35-36 (N.C.U.C. May 30, 2013), *aff'd*, *State ex rel. Utils. Comm'n v. Cooper*, 367 N.C. 444, 761 S.E.2d 640 (2014) (2013 DEP Rate Order).

Moreover, in setting rates the Commission must not only adhere to the dictates of both the United States and North Carolina Constitutions, but as has been held by the North Carolina Supreme Court, it must set rates as low as possible consistent with constitutional law. *Public Staff,* 323 N.C. at 490, 374 S.E.2d at 370. Further, the North Carolina General Assembly has provided that the Commission must also set rates employing a multi-element formula set forth in N.C.G.S. § 62-133. The formula requires consideration of elements beyond just the ROE element, and it inherently necessitates that the Commission make many subjective determinations, in addition to the subjectivity required to determine the ROE. The subjective decisions the Commission must make as to each of the elements of the formula can and often do have multiple and varied impacts on all of the other elements of the formula. In other words, the formula elements are intertwined and often interdependent in their impact to the setting of just and reasonable rates.

The fixing of a rate of return on the cost of property used and useful to the provision of service (as determined through the end of the historic 12-month test period prior to the proposed effective date of a requested change in rates and adjusted for proven changes occurring up to the close of the expert witness hearing) is but one of several interdependent elements of the statutory formula to be used in setting just and reasonable rates. *See* N.C.G.S. § 62-133. North Carolina General Statute § 62-133(b)(4) provides, in pertinent part, that the Commission shall:

> [f]ix such rate of return on the cost of the property . . . as will enable the public utility by sound management [1] to produce a fair return for its shareholders, *considering changing economic conditions and other factors* . . . [2] to maintain

> its facilities and services in accordance with the reasonable requirements of its customers in the territory covered by its franchise, and [3] to compete in the market for capital funds on terms that are reasonable and that are fair to its customers and to its existing investors. [Emphasis added.]

The North Carolina Supreme Court has interpreted the above-emphasized language as requiring the Commission to make findings regarding the impact of changing economic conditions on customers when determining the proper ROE for a public utility. *Cooper I*, 366 N.C. at 495, 739 S.E.2d at 548. The Commission must exercise its subjective judgment so as to balance two competing ROE-related factors — the economic conditions facing the Company's customers and the Company's need to attract equity financing on reasonable terms in order to continue providing safe and reliable service. 2013 DEP Rate Order at 35-36. The Commission's determination in setting rates pursuant to N.C.G.S. § 62-133, which includes the fixing of the ROE, always takes into account affordability of public utility service to the using and consuming public. The impact of changing economic conditions on customers is embedded in the analyses conducted by the expert witnesses on ROE, as the various economic models widely used and accepted in utility regulatory rate-setting proceedings take into account such economic conditions. 2013 DEP Rate Order at 38. Further,

> [t]he Commission always places primary emphasis on consumers' ability to pay where economic conditions are difficult. By the same token, it places the same emphasis on consumers' ability to pay when economic conditions are favorable as when the unemployment rate is low. Always there are customers facing difficulty in paying utility bills. The Commission does not grant higher rates of return on common equity when the general body of ratepayers is in a better position to pay than at other times . . . .

Id. at 37. Economic conditions existing during the modified test year, at the time of the public hearings, and at the date of the issuance of the Commission's order setting rates will affect not only the ability of the utility's customers to pay rates but also the ability of the utility to earn the authorized rate of return during the period the new rates will be in effect. However, in setting the ROE, just as the Commission must assess the impact of economic conditions on customers' ability to pay for service, it likewise must assess the effect of regulatory lag on the Company's ability to access capital on reasonable terms.[7] The Commission sets the ROE considering both of these impacts taken together in its ultimate decision fixing a utility's rates.

Thus, in summary and in accordance with the applicable law, the Commission's duty under N.C.G.S. § 62-133 is to set rates as low as reasonably possible to the benefit of the customers without impairing the Company's ability to attract the capital needed to provide safe and reliable electric service and recover its cost of providing service.

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[7] Regulatory lag can cause a utility's realized, earned return to be less than its authorized return, negatively affecting the shareholder's return on investment as other expenses and debts owed are paid ahead of investor return.

Discussion and Application of Law to the Facts

The Commission has examined the Company's Application and supporting testimony and the exhibits and Form E-1 filings seeking to justify its requested increase. DEC's updated request prior to entering into the stipulations and including the May 2020 Updates was an increase of approximately $414.5 million in annual retail revenues.[8] The Public Staff, which in this docket represents all users and consumers of the Company's electric service, and DEC entered into a stipulation on ROE and capital structure that resulted in reducing the retail revenue increase sought by the Company by $92 million. McManeus Second Settlement Ex. 3. CIGFUR, Commercial Group, Vote Solar, and Harris Teeter each entered into a separate stipulation that, as amended, accepted a 9.60% ROE, subject to certain conditions. As with all settlement agreements, each party to the stipulations gained some benefits that it deemed important and gave some concessions for those benefits. Based on DEC's Application, it is apparent that the stipulations tie the 9.60% ROE to substantial agreed upon concessions made by DEC. As noted above, since the AGO, CUCA, CBD/AV, and the Tech Customers, as well as other parties that did not provide testimony on ROE did not agree to the settlements, the Commission is required to examine the stipulations and exercise its independent judgment to arrive at its own independent conclusion as to the proper ROE.

The starting point for an examination of what constitutes a reasonable ROE begins with the various economic and financial analyses provided by the parties' expert witnesses. In this proceeding, those analyses were provided in the testimonies of eight different witnesses. These testimonies, as summarized above, provide a relatively broad range of methods, inputs, and recommendations regarding the proper ROE determination for DEC. For example, DEC witness D'Ascendis relied in his direct testimony on multiple analyses to arrive at his ROE recommendation. These analyses were a Constant Growth DCF Analysis, a Capital Asset Pricing Model analysis, an Empirical Capital Asset Pricing Model, a Bond Yield Plus Risk Premium analysis, and an Expected Earnings analysis. By way of comparison, Public Staff witness Woolridge and AGO witness Baudino relied upon DCF analyses and CAPM analyses in reaching their conclusions; however, the inputs utilized by these witnesses in their analyses are different from those utilized by witness D'Ascendis. CBD/AV witness McIlmoil recommended an ROE of 9.20% based on an ROE approved for Dominion Energy Virginia in a limited rider proceeding. Commercial Group witness Chriss recommended that the Commission look at the proposed ROE in light of recent ROEs approved by the Commission and by commissions nationwide. Similarly, CIGFUR witness Phillips looked at the average allowed ROEs for both vertically integrated and distribution-only electric utilities of 9.73% and recommended that average as a cap to the allowed ROE. CUCA witness O'Donnell proposed an ROE of 8.75% using the DCF and CAPM methodologies, as well as a comparable earnings approach. Finally, Tech Customers witness Strunk recommended a lower ROE in line with lower risk utilities but did not specify a percentage.

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[8] The revenue requirement impact of the Company's request prior to the stipulations and including the May 2020 Updates was actually a retail revenue increase of approximately $416 million; however, the Company limited its request to $414.5 million.

These varying analyses, as is typical, produced varying results. Witness D'Ascendis' analyses prompted him to propose an ROE range of 10.00% to 11.00% with a specific ROE recommendation of 10.50%. Witness Woolridge's analyses resulted in a recommended ROE range of 6.90% to 8.40% with a primary recommendation of a 9.00% ROE with a 50% common equity capital structure and a secondary recommendation of an 8.40% ROE if DEC's proposed capital structure of 47% long-term debt and 53% common equity was approved. AG witness Baudino proposed an ROE of 9.00%. Finally, as noted above, witness McIlmoil recommended an ROE of 9.20%, witness O'Donnell an ROE of 8.75%, and witness Phillips a cap on ROE of 9.73%.

The Commission finds the cost of equity analyses helpful in reaching its conclusion on an appropriate ROE for DEC but notes that the outputs of the various analyses included in direct testimony span a range from 5.00% to 11.10% and the specific ROE (primary) recommendations of the witnesses span a range from 8.75% on the low end to 10.50% on the high end.[9]

The Commission finds that the updated DCF, Bond Yield Risk Premium, and Expected Earnings analyses of DEC witness D'Ascendis, as well as the Second Partial Stipulation and the other intervenor settlements, are credible, probative evidence, and are entitled to substantial weight.

DEC witness D'Ascendis in his supplemental rebuttal testimony provided his Constant Growth DCF analyses, as shown on Supplemental Rebuttal Exhibit DWD-1, pages 1 and 2, as follows: 30-day dividend yield high ROE mean 9.67%, median 9.42%; and 90-day dividend yield high ROE mean 9.57%. The Commission finds witness D'Ascendis' Constant Growth DCF analyses mean and median ROE results credible, probative, and entitled to substantial weight.

DEC witness D'Ascendis' updated Bond Yield Plus Risk Premium, as shown on Supplemental Rebuttal Exhibit DWD-5, using the current 30-year Treasury yield of 1.47%, the near-term projected 30-year Treasury yield of 1.72%, and the long-term projected Treasury yield of 3.40% and applying it to the approved ROEs in 1,630 electric utility rate proceedings between January 1980 and June 30, 2020, results in ROEs of 10.25%, 10.08%, and 9.96%, respectively. While in the past, the Commission has generally approved the use of current interest rates rather than projected near-term or long-term interest rates, in this particular case, current market conditions give the Commission reason to look beyond the current Treasury yields and give some weight to projected rates. The Commission finds witness D'Ascendis' updated Bond Yield Plus Risk Premium analyses using the current and projected 30-year Treasury yields to be credible, probative, and entitled to substantial weight.

In this case, the Commission is concerned that the low ROEs recommended by CUCA witness O'Donnell, and to a lesser extent the ROEs recommended by AGO witness Baudino, and CBD/AV witness McIlmoil would, when translated into rates and

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[9] As noted *infra*, DEC witness D'Ascendis recommended an ROE of 10.50%, but DEC requested a lower rate of return on equity of 10.30% to mitigate the impact of the rate increase on customers.

holding all other things equal, fail the *Hope* “end results” test. This is shown graphically in Chart 1 of D’Ascendis’ Rebuttal Testimony. Tr. vol. 11, 150. The Commission agrees with witness D’Ascendis that this could result in investors receiving a lower return with greater risk than would be available from other utilities, thereby making it more costly to raise capital. The Commission agrees with witness D’Ascendis that the ROE recommendations of witnesses Baudino, O’Donnell, and McIlmoil are unduly low, places great weight upon this observation, and therefore finds the Baudino, O’Donnell, and McIlmoil ROE recommendations to be unpersuasive. In doing so, the Commission emphasizes that it is referencing the data concerning other authorized ROEs as a means to test the ROE recommendations of witnesses Baudino, O’Donnell, and McIlmoil, and not as a reference to or reliance upon the doctrine of “gradualism.” *See Cooper II*, 367 N.C. at 443. *See also,* Order on Remand, *Application of Virginia Electric & Power Co., d/b/a Dominion North Carolina Power, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, No. E-22, Sub 479, at 33-35 (N.C.U.C. July 23, 2015).

Witnesses Baudino, O’Donnell, and McIlmoil recommended an ROE of 9.00%, 8.75%, and 9.20%, respectively. These recommendations are below the band of authorized ROE results set out in D’Ascendis’ Chart 1. These recommendations are also far below the stipulated 9.90% ROE from the Company’s previous rate case or 10.20% from the rate case prior to that. The recommendations of witnesses Baudino, O’Donnell, and McIlmoil are inconsistent with those recently authorized in North Carolina. The Commission has most recently authorized an ROE of 9.75% for Dominion Energy North Carolina; 9.90% for DEC and DEP in their prior rate cases, and 9.70% for Piedmont Natural Gas Company, Inc. Witness D’Ascendis indicated, and the Commission agrees, that these witnesses’ recommendations are far below the average and median ROE for vertically integrated electric utilities in jurisdictions rated in the top third by Regulatory Research Associates, which range from 9.37% to 10.55%. Witnesses Baudino, O’Donnell, and McIlmoil’s recommendations are below those of other vertically integrated utilities similarly rated from 2015–2020, while the settled ROE of 9.60% falls within that range.

In his direct testimony witness Baudino testified that his 9.00% ROE recommendation was “reasonably close to recently allowed ROEs”, using a 9.68% average ROE determination by commissions in 2017 as “recently allowed ROEs.” Witness Baudino admitted on cross-examination that he “would say [this 68-point differential] was reasonable.” Tr. vol. 2, 136. The differential between the stipulated ROE of 9.60% and witness Baudino’s 9.00% ROE recommendation is 60 basis points — less than the 68 basis points witness Baudino deemed “reasonable.”

There are other aspects of these witnesses’ analyses that the Commission finds lacking. For example, the Commission finds questionable witness Baudino’s failure to adjust his ROE recommendation in his supplemental direct testimony considering the recent volatility in the markets, increase in betas for the companies in the proxy group, and the higher DCF results in his supplemental testimony. Additionally, the Commission agrees with witness D’Ascendis’ criticism of witness Baudino’s growth rates applied to the Constant Growth DCF model and his reliance on the Constant Growth DCF model to determine the Company’s ROE, as well as the reasonableness of his Bond Yield Plus

Risk Premium analysis among other factors. Finally, the Commission also gives no weight to witness Baudino's CAPM approach as witness Baudino himself disregarded its unreasonably low results.

Regarding the ROE recommendation of CUCA witness O'Donnell, as with witness Baudino, his reliance on historical growth rates in the DCF analysis does not adequately encapsulate how the model is a forward-looking measure of investors' expectations. Further, the Commission finds compelling witness D'Ascendis' test of the relationship between retention ratios and future growth rates demonstrating that earnings growth actually decreased as the retention ratio increased, thereby undermining the premise underlying witness O'Donnell's use of the Retention Growth Model. As for witness O'Donnell's Comparable Earnings Approach, his updated forward-looking 2019 and 2022–2025 analysis yielding ROE estimates of 10.00% and 10.60% for his proxy group was similar to witness D'Ascendis' updated Expected Earnings analysis of 10.18% to 10.55%. Overall, it seems that witness O'Donnell's 8.75% ROE estimate is at odds with the data he presented.

Witness McIlmoil first proposed that the Commission use an ROE that the Virginia State Corporation Commission determined was appropriate for a Dominion Energy Virginia in a limited rider proceeding with a dead band. In his summary, witness McIlmoil lowered his recommended ROE to 9.00%, adopting the recommended ROE of another witness. The Commission declines to adopt this recommendation.

Additionally, witness D'Ascendis testified that the intervenor witnesses fail to recognize the risks faced by the Company and do not appropriately reflect the evolving capital market environment. Tr. vol. 11, 148. A significant departure from the authorized ROEs of other similarly situated utilities impacts the Company's ability to compete with other companies for long-term capital to provide safe and reliable utility service. The Commission notes the risk that an ROE in the range recommended by witnesses Baudino, O'Donnell, and McIlmoil could impact the Company's ability to compete for capital, as illustrated by witness D'Ascendis in his discussion of a recent rate decision in which the financial community responded negatively to an adverse regulatory outcome for CenterPoint Energy Houston Electric.

In sum, in light of all of the factors discussed in this Order, the Commission places minimal weight upon the ROE recommendations of witnesses O'Donnell, Baudino, and McIlmoil. Witness Strunk criticized the Company's ROE recommendation as excessive. In response, witness D'Ascendis noted in his second settlement testimony that the average authorized ROE for vertically integrated electric utilities from 2016 to June 2020 was 9.74%, 14 basis points above the stipulated ROE.

The Commission, of course, does not blindly follow ROE results allowed by other commissions. The Commission determines the appropriate ROE based upon the evidence and particular circumstances of each case. However, the Commission believes that the ROE trends and decisions by other regulatory authorities deserve some consideration, as (1) they provide a check or additional perspective on the case-specific circumstances, and (2) the Company must compete with other regulated utilities in the capital markets, meaning that an ROE significantly lower than that approved for other utilities of comparable risk would undermine the Company's ability to raise necessary capital, while an ROE significantly higher than other utilities of comparable risk would result in customers paying more than necessary. Both of those outcomes are undesirable and would result in unjust and unreasonable rates. The fact that the approved ROE falls 14 basis points below the average and within the range of recently approved ROE for other vertically integrated electric utilities lends support to the Commission's approval.

The record contains substantial evidence supporting the reasonableness of the stipulated ROE of 9.60%. The Commission notes generally that this ROE is well within the range of recommended returns by the economic experts in this docket of 8.75% to 10.50%. More specifically, an ROE of 9.60% falls within D'Ascendis' range under his constant growth DCF analyses and his Expected Earnings Analysis. Supplemental Rebuttal Ex. DWD-6. In prior cases, the Commission has given significant weight to the results of the Expected Earnings methodology, which stands separate and apart from the market-based methodologies (*e.g.,* the DCF or CAPM) also used by ROE experts. *See, e.g.*, 2013 DEP Rate Order at 36. The Commission chooses to do so again in this case. Moreover, 9.60% falls squarely within the range and very close to the average of recently allowed ROEs for vertically integrated electric utilities nationally. Lastly, the Commission notes that the stipulated ROE is 70 basis points lower than the ROE the Company requested in its Application. As such, the Commission concludes that 9.60%, is within the "zone of reasonableness" that leading commentators and the North Carolina Supreme Court have indicated is presumptively just and reasonable. *See State ex rel. Utils. Comm'n v. Gen. Tel. Co.*, 285 N.C. 671, 681, 208 S.E.2d 681, 688 (1974) (a "zone of reasonableness extending over a few hundredths of one per cent" exists within which the Commission may appropriately exercise its discretion in choosing a proper ROE).

As the Supreme Court made clear in *CUCA I* and *II*, the Commission should give full consideration to a nonunanimous stipulation itself, along with all evidence presented by other parties, in determining whether the stipulation's provisions should be accepted. *CUCA I*, 348 N.C. at 466, and *CUCA II*, 351 N.C. at 231, In this case, insofar as expert ROE testimony is concerned, both witnesses D'Ascendis and Woolridge support an ROE at 9.60%. Tr. vol. 11, 368 (D'Ascendis); tr. vol. 17, 225-26 (Woolridge). Only witnesses Baudino and McIlmoil questioned the settlement ROE, tr. vol. 2, 133; tr. vol. 10, 125, but, as indicated above, the Commission places very little weight upon their ROE recommendations. The Commission does note, however, that other intervenor settlements, as amended, support the use of an ROE of 9.60%. Thus, the Commission finds and concludes that the Second Partial Stipulation itself, along with the expert testimony of witnesses D'Ascendis and Woolridge, is credible evidence of the appropriate ROE and is entitled to substantial weight in the Commission's ultimate determination of this issue.

In summary, the Commission concludes that there is substantial evidence supporting the reasonableness of an ROE of 9.60%.

However, to meet its obligation as set forth in *Cooper I*, the Commission must address the impact of changing economic conditions on customers.

In this case, all parties had the opportunity to present the Commission with evidence concerning changing economic conditions as they affect customers. The testimony of witnesses D'Ascendis, Woolridge, and Baudino, which the Commission finds entitled to substantial weight, addresses changing economic conditions at some length. Witness D'Ascendis provided detailed data concerning changing economic conditions in North Carolina, as well as nationally, and concluded that the North Carolina-specific conditions are "highly correlated" with conditions in the broader nationwide economy. As such, witness D'Ascendis testified that changing economic conditions, both nationally and specific to North Carolina, are reflected in his ROE estimates.

Public Staff witness Woolridge agreed with DEC witness D'Ascendis that as of the time of the filing of his testimony, economic conditions had improved in North Carolina. He pointed out that at the time of the filing of his testimony, while the unemployment rates in North Carolina and DEC's service territory had fallen by two-thirds since their peaks in the 2009-2010 period, they were both above the national average of 3.90%. Witness Woolridge also noted that while North Carolina's residential electric rates are below the national average, its median household income is more than 10% below the U.S. norm.

However, subsequent to the filing of this case and as a result of the COVID-19 pandemic, economic conditions deteriorated in North Carolina and across the country during the first half of 2020. The Commission gives weight to the testimony of witness Baudino regarding the national decline of the GDP in the first quarter of 2020 by 5.0% as unemployment rose to 12.90% and 13.30% in May in North Carolina and the U.S., respectively. The Commission likewise gives weight to the testimony of witness D'Ascendis regarding the national and State unemployment rates in July of 10.2% and 8.5%, respectively, reflecting a quick rebound of at least some of the economic activity lost during the downturn.

As the Commission has noted, customer impact due to changing economic conditions is embedded in ROE expert witness analyses. Witness D'Ascendis' analysis, which the Commission finds credible and to which the Commission gives weight, indicates that even though the North Carolina and U.S. economies have contracted, economic conditions in North Carolina continue to be highly correlated to conditions nationally, and, therefore, continue to be reflected in the analyses used to determine the allowed ROE. Witness D'Ascendis' testimony regarding correlation between U.S. and North Carolina GDP growth for the fifteen years and four quarters ended March 2020, and employment in the US and DEC's service territories from February to May 2020, demonstrate this point. The Commission also observes witness D'Ascendis' testimony that North Carolina's economy had been affected somewhat less severely than the national economy and its economic recovery had been somewhat more rapid.

Therefore, the Commission determines that the econometric data relied upon by ROE expert witnesses captures the effects and impacts of changing economic conditions upon customers.

Based upon the general state of the economy and the need for the continuing affordability of electric utility service, and after weighing and balancing factors affected by the changing economic conditions in making the subjective decisions required, the Commission concludes that the stipulated ROE of 9.60% will not cause undue hardship to customers, even though, the Commission acknowledges, some customers will struggle to pay for electric utility service.

Many of the adjustments to the Company's proposed rate increase reduce ratepayer responsibility and equity investor returns in compliance with the Commission's responsibility to establish rates as low as reasonably permissible without transgressing constitutional constraints, and thus, inure to the benefit of consumers' ability to pay their bills in this economic environment.[10] For example, to the extent the Commission made downward adjustments to rate base, disallowed test year expenses, increased test year revenues, or reduced the equity capital structure component, the Commission reduced the rates consumers will pay during the future period when rates will be in effect. In this case, the Commission has ordered negative adjustments to many expenses sought to be included in the Company's revenue requirement. Because the compensation owed to investors for investing in the Company's provision of service to consumers takes the form of return on investment, downward adjustments to rate base, disallowances of test year expenses, increases to test year revenues, or reduction in the equity capital structure component will reduce investors' return on investment irrespective of the determination of ROE.

The Commission has also approved herein an annual $2.5 million shareholder contribution to the Share the Warmth Fund in 2021 and 2022, as provided in the Second Partial Stipulation, and an annual contribution of $3 million, in conjunction with DEP, to the Helping Home Fund for two years, for a total contribution of $11 million of the Company's shareholder funds for energy assistance to low-income customers. NCSEA/NCJC et al. Stipulation, § IV. These decisions directly benefit customers with the least ability to pay in the current economic environment. The Commission takes these facts into account when approving the 9.60% ROE.

The Commission also recognizes that the Company is in a significant construction mode and much of the associated investment is for generation, transmission, and distribution infrastructure to benefit DEC's customers, as well as in response to recent increases in environmental compliance costs and other operating expenses. The need to invest significant sums to serve its customers requires the Company to maintain its creditworthiness in order to compete for large sums of capital on reasonable terms. The Commission must weigh the impact of changing economic conditions on DEC's customers against the benefits that those customers derive from the Company's ability to provide safe, adequate, and reliable electric service. Safe, adequate, and reliable electric service is essential to the well-being of the people, businesses, institutions, and economy

[10] The Commission notes that consumers pay "rates," a charge in cents per kilowatt-hour, for the electricity they consume. They do not pay a "rate of return on common equity," though it is a component of the Company's cost of providing service which is built into the charge per kilowatt-hour. Investors are compensated by earning a return on the capital they invest in the business. Per the Commission determination of the ROE in this matter, investors will have the opportunity to be paid in dollars for the dollars they invested at the rate of 9.60%.

of North Carolina. Thus, the Commission finds and concludes that such capital investments by the Company provide significant benefits to all of DEC's customers.

The Commission concludes in the exercise of its independent judgment and discretion that a 9.60% ROE is supported by the greater weight of the evidence and should be adopted. The hereby approved ROE appropriately balances the benefits received by DEC's customers from DEC's provision of safe, adequate, and reliable electric service in support of the well-being of the people, businesses, institutions, and economy of North Carolina (which benefits are symbiotically linked to the Company's ability to compete in the equity capital market to access capital on reasonable terms that will be fair to ratepayers) with the difficulties that some of DEC's customers will experience in paying DEC's adjusted rates. The Commission further concludes that a 9.60% ROE will allow DEC to compete in the market for equity capital, providing a fair return on investment to its investor-owners, and that the lowering of the rate from the requested 10.30% to 9.60% has the effect of lowering the cost of service which forms the basis of the rates the ratepayers must pay for service. Accordingly, the Commission concludes, taking into account changing economic conditions and their impact on customers, that the approved ROE will result in the lowest rates constitutionally permissible in this proceeding.

Finally, in approving the 9.60% ROE, the Commission gives significant weight to the stipulations and the benefits that they provide to DEC's customers, which the Commission is obliged to consider as an independent piece of evidence under the Supreme Court's holding in *CUCA I*.

As a result, the Commission concludes that the 9.60% stipulated ROE is reasonable and appropriate and is supported by the greater weight of the substantial evidence in the record.

B. Capital Structure

Summary of the Evidence

In DEC's Application witness Newlin proposed using a capital structure of 53% members' equity and 47% long-term debt. Tr. vol. 11, 381. Witness Newlin testified that the Company's "specific debt/equity ratio will vary over time, depending on a variety of factors, including among other things, the timing and size of capital investments and payments of large invoices, debt issuances, seasonality of earnings, and dividend payments to the parent company." *Id. at* 395-96. As of December 31, 2019, DEC's capital structure was 52% common equity and 48% long-term debt. Tr. vol. 17, 228.

In his direct testimony CUCA witness O'Donnell recommended that the Commission reject the Company's capital structure proposal and instead advocated a 50/50 structure. Witness O'Donnell's analysis supporting his 50/50 capital structure recommendation was based on his comparison of capital structures of publicly traded holding companies, not operating utility companies. Tr. vol. 20, 144.

Public Staff witness Woolridge testified that the Company's proposed capital structure included more common equity than the average of the proxy group he used in conducting his analysis. Tr. vol. 17, 110-11. He stated that it is appropriate to use the common equity ratios of the parent holding companies and that the high debt ratio and low equity ratio of DEC's parent company, Duke Energy, is credit negative for DEC as evaluated by Moody's. He noted, however, that because DEC is a regulated business, it is exposed to less business risk and can carry relatively more debt in its capital structure than most unregulated companies, like Duke Energy. *Id.* at 113-16. Witness Woolridge further testified that DEC should take advantage of its lower business risk to employ cheaper debt capital at a level that will benefit its customers through lower revenue requirements and, as a result, recommended a capital structure of 50% common equity and 50% debt based on a 9.00% ROE. Witness Woolridge also made an alternative capital structure recommendation of the Company's proposed structure of 47% long-term debt and 53% common equity based on an 8.40% ROE. *Id.* at 118-19.

AGO witness Baudino recommended that the Commission reject the Company's requested ratio and instead recommended the Commission approve the Company's December 2018 capital structure, which includes a common equity of 51.50%. Tr. vol. 16, 319, 382. As noted above, witness Baudino's recommendation is lower than the Company's recent actual capital structure of 52% equity and 48% long term debt.

Tech Customers witness Strunk concluded that the Company's proposed equity ratio is "above the mean and median equity ratio awarded" for other vertically integrated electric utilities across the country and therefore indicative of low financial risk. *Id.* at 141. Additionally, witness Strunk did not recommend a specific equity ratio, but did include in his proxy group 16 of 28 companies which have been authorized equity ratios above the 50% equity ratio recommended by witness O'Donnell. *Id.*

In his rebuttal testimony witness Newlin pointed out that CUCA witness O'Donnell utilized data showing capital structures that were inappropriate to use because they do not differentiate between various types of utility companies, which present different risk profiles. Tr. vol. 11, 403. Witness D'Ascendis testified that parent and operating companies do not necessarily have the same capital structures because financing at each level is driven by "the specific risks and funding requirements associated with their individual operations." Tr. vol. 11, 244. He noted the Commission's previous rejection of the use of parent company structures as opposed to operating company structures in determining the operating utility's appropriate equity/debt ratio. *See* Order Accepting Stipulation, Deciding Contested Issues, and Granting Partial Rate Increase, *Application by Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, No. E-2, Sub 1142, at 87-88 (Feb. 23, 2018), *aff'd, in part, and remanded*, *State ex rel. Utils. Comm'n v. Stein*, 375 N.C. 870, 851 S.E.2d 237 (2020) (2018 DEP Rate Order); Order Granting General Rate Increase and Approving Amended Stipulation, *Application of Duke Energy Carolinas, LLC, for an Increase in and Revisions to Its Rates and Charges Applicable to Electric Utility Service in North Carolina*, No. E-7, Sub 909, at 27-28 (Dec. 7, 2009) (2009 DEC Rate Order).

In addition, witness D'Ascendis noted the use of the operating subsidiary's actual capital structure — that is, the capital actually funding the utility operations that provide service to customers — is entirely consistent with precedent of the FERC so long as three criteria are met: the operating subsidiary (1) issues its own debt without guarantees, (2) has its own bond rating, and (3) has a capital structure within the range of capital structures for comparable utilities. *Id.* at 258-89. Witnesses Newlin and D'Ascendis testified that DEC, which issues its own debt and has its own bond rating, has a capital structure that is generally consistent with that of other operating companies, especially vertically integrated companies. *Id.* at 414-15 (Newlin); *id*. at 260 (D'Ascendis). Further, in response to witness O'Donnell, witness D'Ascendis testified that by excluding equity ratios authorized in jurisdictions that include non-investor supplied capital in the capital structure, witness O'Donnell's review demonstrated an average and median authorized equity ratio in 2019 of 51.93% and 52% for vertically integrated utilities. Tr. vol. 11, 325. Thus, he noted that the stipulated 52% equity ratio is consistent with authorized equity ratios. *Id.* DEC witness D'Ascendis also pointed out that witness Strunk, like witness O'Donnell, considers jurisdictions in which non-investor supplied capital is included in the capital structure, thus biasing his review. *Id.* at 334.

Subsequent to the filing of testimony, the Company reached several separate stipulations with the Public Staff, CIGFUR, Commercial Group, Harris Teeter, Vote Solar, NCSEA, and NCJC et al. agreeing that the rates in this proceeding should be set using a capital structure of 52% equity and 48% long-term debt. The 52% equity capital structure agreed to in the settlement agreements represents a compromise between the Company's 53% equity position and the intervenors' recommendations ranging from a 50% to a 51.50% equity capital structure.

Under Section III.B of the Second Partial Stipulation, DEC and the Public Staff proposed a capital structure of 52% common equity and 48% long-term debt. In their stipulation testimony Company witness Newlin and Public Staff witness Woolridge testified that the capital structure reflected in the Second Partial Stipulation represents a compromise by both parties in an effort to reach agreement and is in the public interest. Witness De May's second settlement testimony also supported the stipulated 52/48 capital structure. Tr. vol. 11, 888.

Discussion and Conclusions

In evaluating the evidence on capital structure in this proceeding the Commission first notes that the equity/debt ratios reflected in the Second Partial Stipulation and the stipulations with CIGFUR, Commercial Group, Harris Teeter, Vote Solar, NCSEA, and NCJC et al. of 52% equity and 48% long-term debt are consistent with and well within the prior decisions of the Commission.[11] That consistency is not a determinative factor from

[11] *See* DENC Docket No. E-22, Sub 532 Order (51.75% common equity and 48.25% debt); PSNC Sub 565 Order (52.0% common equity, 44.62% long-term debt, 3.38% short-term debt); PNG Sub 743 Order (52.00% equity, 47.15% long-term debt, 0.85% short-term debt); DEC Sub 1146 Order (52% common equity and 48% long-term debt); DEP Sub 1142 Order (52% common equity and 48% long-term debt); DENC Sub 562 Order (52% common equity and 48% long-term debt).

the Commission's perspective, but the prior decisions provide some context supporting the reasonableness of the stipulated capital structure.

Based upon its own review and independent analysis of the evidence, the Commission concludes that there is substantial evidence that a capital structure of 52% equity and 48% long-term debt, as is reflected in Section III.B. of the Second Partial Stipulation and the stipulations with CIGFUR, Commercial Group, Harris Teeter, Vote Solar, NCSEA, and NCJC et al. is just, reasonable, and appropriate on several grounds.

First, this capital structure is the same capital structure authorized for DEC in its last rate case. Second, this capital structure was accepted by the Public Staff, CIGFUR, the Commercial Group, Vote Solar, and Harris Teeter in separate stipulations. Third, the Commission gives great weight to Company witness Newlin's testimony that the stipulated capital structure is reasonable and appropriate when viewed in the context of the overall Second Partial Stipulation. Fourth, the Commission places great weight as well on witness Woolridge's conclusion that the end result of the settlement is fair and reasonable with respect to both ratepayers and shareholders, and that customers will benefit from lower rates as a result of a negotiated settlement. Fifth, the Commission also gives weight to the Second Partial Stipulation and the benefits that it provides to DEC's customers, which the Commission is obliged to consider as an independent piece of evidence under *CUCA I* and *II*. Each party to the Second Partial Stipulation gained some benefits that it deemed important and gave some concessions for those benefits. Based on the Application and prefiled testimony, it is apparent that the Second Partial Stipulation ties the 52% equity, 48% long-term debt capital structure to substantial concessions the Company made to reduce its revenue requirement. Sixth, the Commission gives weight to the Stipulations with CIGFUR, the Commercial Group, Harris Teeter, Vote Solar, NCSEA, and NCJC et al. as it did to the Second Partial Stipulation.

Accordingly, based on the matters set forth above, and in the exercise of its independent judgment, the Commission finds that a preponderance of the evidence weighs in favor of the stipulated capital structure pursuant to Section III.B. of the Second Partial Stipulation and the stipulations with CIGFUR, Commercial Group, Harris Teeter, Vote Solar, NCSEA, and NCJC et al. and that such capital structure is just, reasonable, and appropriate for use in setting rates in this docket.

C. Cost of Debt

DEC witness Newlin testified that the Company's long-term debt cost as of December 31, 2018, was 4.51%, which was the value used to determine the revenue requirement in the Company's Application. As part of Section III.B of the Second Partial Stipulation, DEC and the Public Staff agreed to the May 2020 embedded cost of debt of 4.27%. The Commission finds for the reasons set forth herein that a 4.27% cost of debt is just and reasonable.

In his supplemental testimony Public Staff witness Woolridge initially proposed an updated cost of long-term debt (as of January 31, 2020) of 4.29%, and DEC updated its cost of debt to 4.29% in supplemental testimony filed July 6, 2020. Tr. vol. 17, 230. As part of the give-and-take negotiations involved in the settlement process, DEC and the Public Staff agreed to an updated cost of long-term debt (updated through May 2020) of 4.27%. *Id.*

No intervenor offered evidence to contradict the use of 4.27% as the cost of debt. The Commission therefore finds and concludes that the use of a debt cost of 4.27% per the terms of Section III.B of the Second Partial Stipulation is supported by the greater weight of the substantial evidence and is just and reasonable to all parties in light of all the evidence presented.

D. Credit Metrics

Summary of the Evidence

DEC Direct Testimony

Witness Newlin

DEC witness Newlin testified that his responsibilities as Senior Vice President, Corporate Development and Treasurer for Duke Energy include managing Duke Energy and its subsidiaries' credit ratings and interactions with major credit rating agencies. His testimony addressed DEC's financial objectives, capital structure, cost of capital, credit ratings, and forecasted capital needs. Witness Newlin emphasized the importance of DEC's continued ability to meet its financial objectives. He stated that the Company's proposed rate increase will allow it to recover prudently incurred costs, compete in the capital markets for needed capital, and preserve its financial standing with both debt and equity investors, as well as the credit rating agencies, to the long-term benefit of its customers. Consolidated Tr. Vol. 2, 376-79.

Witness Newlin testified that DEC has substantial capital needs over the next several years and that financial strength and access to capital at all times are necessary for DEC to provide service to its customers. To maintain its financial strength and flexibility, including its strong investment grade credit ratings, DEC has specific objectives including: (1) maintaining at least 53 percent common equity, (2) ensuring timely recovery of prudently incurred costs, (3) maintaining sufficient cash flows to meet obligations, and (4) maintaining a sufficient return on common equity to fairly compensate shareholders. *Id.* at 379.

Witness Newlin explained credit quality and credit ratings and how they are determined by the two major credit ratings agencies, Standard & Poor's (S&P) and Moody's Investor Service (Moody's). In assessing credit quality these agencies consider many qualitative and quantitative factors in assigning credit ratings. Qualitative factors may include DEC's regulatory climate, its track record for delivering on commitments, strength of management, its operating performance, and the economic vitality and customer profile of its service area. Quantitative measures are primarily based on operating cash flow and focus on the level at which DEC maintains financial leverage in relation to its generation of cash and its ability to meet its fixed obligations based on internally generated cash, such as its debt to capital ratio. Witness Newlin also provided the credit ratings by S&P and Moody's on DEC's outstanding debt, as of September 19, 2019, which show that DEC carries a credit rating compatible with strong, investment-grade securities, subject to low risk for an investor. *Id.* at 382-83.

However, according to his testimony, the ratings agencies have identified several challenges that DEC faces in maintaining its current credit ratings. These include downward pressure on credit metrics due to regulatory lag in the recovery of coal ash basin closure costs, reduced cash flows due to federal tax reform, and elevated capital expenditures. He elaborated that the Federal Tax Cut and Jobs Act of 2017 (Tax Act) resulted in electric utilities, including DEC, and their holding companies losing some of their cash flow from deferred taxes on an ongoing basis. He testified that this loss of cash flow would reduce DEC's funds from operations to debt ratio (FFO/Debt), a key credit metric. Because DEC's EDIT are customer-supplied funds, he testified that DEC proposes to flow the EDIT not subject to a statutory required flowback period over 20 years. In his opinion a 20-year period balances both the interest of customers and the financial strength of the Company and would smooth out the reduction in cash flow to DEC as it returns the EDIT to customers. *Id.* at 385-92.

Public Staff Direct Testimony

Witness Hinton

Public Staff witness Hinton testified to address concerns raised by Company witnesses Newlin and De May with regard to the credit metrics and the risk of a downgrade of DEC's credit ratings. He also testified in support of the Public Staff's recommended flowback of unprotected EDIT over a five-year period. Tr. vol. 17, 445.

Witness Hinton testified that DEC had provided the Public Staff with projected FFO/Debt credit metrics using both the five-year flowback period for unprotected EDIT recommended by the Public Staff and the 20-year flowback recommended by DEC. He noted that in Moody's October 31, 2019 Credit Opinion for DEC, an FFO/Debt metric that is between 24% to 26% qualifies for an "A" rating. He testified that the FFO/Debt metric would only be below 24% in 2021 with a five-year flowback. In his opinion, a temporary decrease in FFO/Debt would not likely lead to a downgrade of the Company's "Aa2" ratings on its first mortgage bonds or its "A1" senior unsecured bonds. Based on his analyses, he believes that unexpected financial developments would have to occur that reduced DEC's cash flow from operations or caused the Company to issue more debt to trigger a downgrade. In addition, he testified that Moody's and S&P place weight on factors other than credit metrics and that DEC has other means to finance the EDIT flowback over the five-year period, such as equity. Finally, witness Hinton testified that even if DEC's first mortgage bonds were downgraded by one notch to "Aa3," it is reasonable to expect that the investor-required bond yield would increase by five basis points under current market conditions and the downgrade would probably last less than five years. *Id.* at 445-52.

DEC Rebuttal Testimony

Witness Newlin

In rebuttal testimony DEC witness Newlin testified that he disagreed with Public Staff witness Hinton's advocacy for a five-year flowback of unprotected EDIT instead of the 20-year period proposed by the Company. He stated that reducing the Company's cash flow through a more accelerated flowback of unprotected EDIT at the same time that DEC is investing in large capital projects and refinancing obligations will negatively impact its credit metrics, which must be taken into account. Witness Newlin noted that in October 2018 Moody's, in its Credit Opinion of DEC, identified tax reform as one of the several factors that could adversely impact the Company's financial metrics (specifically, cash flow coverage ratios). Tr. vol. 11, 417-18.

Witness Newlin testified that it is reasonable that customers should benefit from the Tax Act and they will. However, he submitted that without the Commission's thoughtful consideration regarding all aspects of the Tax Act, particularly through a reduction in cash flow, the Company's credit quality could be adversely affected. He stated that an accelerated return of EDIT over an arbitrary five-year period would adversely impact the Company's cash flow and FFO/Debt ratio. Furthermore, witness Hinton's analysis focuses on EDIT flowback in isolation and does not consider the cumulative impact of other credit-negative proposals by the Public Staff including a lower return on equity, a more leveraged capital structure, disallowance of a return on coal ash costs, and other recommendations for ratemaking that would reduce cash flows and increase debt. *Id.* at 420-22.

Witness Newlin also testified that witness Hinton's estimate of a five-basis point increase in debt cost as a result of a downgrade is based on capital market conditions reflecting historically low interest rates and near record tight credit spreads. He testified that credit spreads can widen significantly during periods of uncertainty and market volatility. With regard to witness Hinton's estimate that a downgrade could last only five years, witness Newlin stated that five years is a long time, and such a presumption is overly optimistic. Witness Newlin noted that Moody's mentions a downgrade would occur if FFO/Debt is below 25% on a sustained basis. However, witness Newlin testified that an upgrade would require significantly higher metrics and would require approximately $300 million in incremental annual cash flows on a sustained basis with no additional leverage to achieve a 30% FFO/Debt ratio, which would likely require significant rate increases over prolonged periods. *Id.* at 423-25.

Witness Young

DEC witness Young, Executive Vice President and Chief Financial Officer for Duke Energy, testified in rebuttal on the financial needs of Duke Energy investors, the impact of utility regulation on the Company's credit profile and investors, the benefits to customers of having a financially healthy utility, the Company's concerns with some of the proposals offered by intervenors in this proceeding (and with the Commission's recent Dominion Energy North Carolina Order issued in Docket No. E-22, Sub 562), and the reasons those proposals should not be adopted by the Commission in this proceeding. Tr. vol. 11, 441.

Witness Young testified that neither Duke Energy nor DEC has access to any established “reserves” to pay the carrying costs of unavoidable debt (and supply equity) needed to support utility operations. He testified that having to simply absorb those carrying costs could have significant negative implications to the financial stability of the enterprise as a whole. Witness Young explained that energy utility operations are often cash flow negative due to the need to serve a growing customer base, repair and maintain existing infrastructure, and immediately respond to all service interruptions such as those caused by major storms. Duke Energy’s ability to fund these investments is based upon investor confidence that customer rates will be set at levels that allow all prudent utility operating and financing costs to be recovered. *Id.* at 448.

Witness Fetter

DEC rebuttal witness Fetter, a consultant of DEC, testified mainly in response to the Public Staff’s recommendation for an equitable 50/50 sharing of CCR compliance costs. Utilizing his past experience as a state utility commission chairman and head of the utility rating practice at Fitch, Inc., he discussed how the adoption of such a recommendation would be inappropriate and viewed negatively by the credit rating agencies and investors. Tr. vol. 26, 88.

Witness Fetter testified that DEC corporate issuer credit ratings span between the highest level (A1, Stable outlook at Moody’s) and the lowest level (A-, Stable outlook at S&P) of the “A” category. He testified that a regulated utility should endeavor to hold no lower than Baa1 (Moody’s) to BBB+ (S&P), with a longer-term goal of moving into or maintaining the A category. *Id.* at 67.

Witness Fetter testified that the most qualitative factors used by rating agencies are regulation, management, and business strategy, along with access to energy, gas and fuel supply with timely recovery of associated costs. He testified that credit rating agencies look for the consistent application of sound economic and regulatory principles by utility regulators. *Id.* at 68, 70.

Witness Fetter testified that the financial community’s view of the Commission has been relatively positive. He testified that Regulatory Research Associates (RRA) currently rates the North Carolina regulatory environment, which goes beyond the Commission to also include legislative and executive branch policies, as Average 1, among the top one-third of the 53 regulatory jurisdictions currently rated by RRA. He testified that RRA’s view of North Carolina’s regulation as overall relatively constructive from an investor viewpoint serves as a positive factor in the credit rating analytical process. *Id.* at 74.

Witness Fetter testified that Moody’s cautions that a DEC credit downgrade could occur if there is a decline in the credit supportiveness of DEC’s regulatory relationships, particularly with regards to coal ash remediation recovery in North Carolina. *Id. at* 75. He stated that the Public Staff’s sharing recommendation undercuts both the quantitative and qualitative factors that are positives in the credit rating agencies' assessment of DEC's ratings. The equitable 50/50 sharing proposal, in his opinion, is inconsistent with the core regulatory principle that prudently incurred costs should be allowed for recovery in customer rates. He testified that this principle is fundamental to the regulatory compact that undergirds investor willingness to provide needed funding to public utilities in exchange for a fair return or investment. Based upon his background he believes that a stark movement away from traditional ratemaking principals, which would also be a clear break away from past Commission precedent, would shake the perception of investors and increase the costs of both equity and debt capital, an impact that ultimately lands at the doorstep of the customer. Accordingly, he recommended that the Company should seek to achieve excellent operating performance going forward and that the Commission should sustain the ongoing constructive regulatory environment, which together should maintain the Company's credit ratings no lower than their current levels within the "A" category. *Id. at* 379-80.

Discussion and Conclusions

The Commission notes that the parties submitted a considerable amount of testimony explaining credit metrics, quality, and ratings. The Company, in particular, shared its views on the potential impact of the Commission's decisions on several issues in this proceeding with regard to possible future credit ratings changes and investor perceptions. The Commission found such testimony to be informative and appreciates the efforts of the parties in this regard.

The Commission recognizes and acknowledges that its decisions on important issues in general rate cases are part of the regulatory climate of a public utility operating within North Carolina and are critically reviewed by credit rating agencies. So too are the statutory framework and appellate court decisions. Ultimately, utility management is responsible for managing credit metrics and ratings and investor perceptions. It is they who have levers, such as timing and selection of future capital project spending, issuances of securities and dividend policy, managing daily operations efficiently, and even the provision of a convincing evidentiary record when prudency issues are raised in a proceeding such as this one.

North Carolina General Statutes Section 62-133 sets forth the factors to be considered by the Commission in setting rates for public utilities, stating:

> In fixing rates for any public utility subject to the provisions of this Chapter, . . . the Commission shall fix such rates as shall be fair to both the public utilities and to the consumer.

N.C.G.S. § 62-133(a). The statute further provides that "[t]he Commission shall consider all other material facts of record that will enable it to determine what are reasonable and just rates." N.C.G.S. § 62-133(d).

The statute does not require that the Commission consider the utility's credit ratings or stock prices when fixing rates, a fact that was conceded by DEC witnesses.

However, the Commission must set rates that are reasonable and fair to both its customers and existing investors and should allow the utility to compete in the capital markets on reasonable terms.

The Commission has decided the issues in this proceeding based upon the requirements of N.C.G.S. § 62-133. The Commission has given the evidence on credit metrics due consideration. The rates fixed by this Order are supported by the greater weight of the evidence, are fair to both the public utilities and customers, produce just and reasonable rates, and should allow the utility, through prudent management, to access the capital markets on reasonable terms. Indeed, as to the last point the Commission views the ROE and capital structure approved herein to be investor and credit supportive.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 36

Cost of Service Adjustments

The evidence supporting this finding of fact is found in the verified Application and Form E-1; the Public Staff First and Second Partial Stipulations; the testimony and exhibits of DEC witnesses McManeus, Metzler, Speros, Hatcher, Pirro, Kuznar, and Hager, Public Staff witnesses Boswell, Saillor, Metz, McLawhorn, and Maness, and CBD/AV witness Ryan; and the entire record in this proceeding.

Summary of the Evidence

As previously discussed, DEC and the Public Staff reached partial settlements with respect to many of the revenue requirement issues presented by the Company's Application, including those arising from the supplemental and rebuttal testimonies and exhibits. Section III of the First Partial Stipulation outlines a number of accounting adjustments to which DEC and the Public Staff have agreed, as does Section III.J. of the Second Partial Stipulation. The accounting adjustments that are not specifically addressed in other findings and conclusions are discussed in more detail below.

Executive Compensation and Incentive Compensation

In its Application the Company removed 50% of the compensation of the five Duke Energy executives with the highest level of compensation allocated to DEC in the test period. Witness McManeus explained that while the Company believes these costs are reasonable, prudent, and appropriate to recover from customers, DEC has for purposes of this case made an adjustment to this item. Tr. vol. 11, 476. Public Staff witness Boswell recommended an additional adjustment to remove 50% of the benefits associated with these top five Duke Energy executives. Tr. vol. 17, 248-49. She contended that this adjustment is consistent with the positions taken by the Public Staff and approved by the Commission in past general rate cases involving investor-owned electric utilities serving North Carolina retail customers and that it is appropriate and reasonable for the shareholders of the larger electric utilities to bear some of the cost of compensating those individuals who are most closely linked to furthering shareholder interests. *Id.* at 249-50. Witness Boswell also recommended disallowance of incentive compensation related to

EPS and total shareholder return (TSR). *Id.* at 251-52. She asserted that incentive compensation tied to EPS and TSR metrics should be excluded because it provides a direct benefit to shareholders only, rather than to customers. *Id.* at 252.

In her rebuttal testimony Company witness Metzler testified that the Public Staff's proposed adjustments are inappropriate and should be rejected by the Commission. Tr. vol. 11, 807. According to witness Metzler employee compensation and incentives tied to metrics such as EPS and TSR benefit customers because those metrics reflect how employees' contributions translate into overall financial performance. *Id.* at 814.

Additionally, witness Metzler explained that in order to attract a well-qualified and well-led workforce the Company must compete in the marketplace to obtain the services of these employees. Finally, witness Metzler pointed out that no witness in this proceeding challenged the reasonableness of the level of compensation expenses reflected in the test period. *Id.* at 815.

The First Partial Stipulation provides that "[t]he Company accepts the Public Staff's proposed adjustment to executive compensation to remove 50% of the benefits associated with the five Duke Energy executives with the highest amounts of compensation, in addition to the 50% of their compensation removed in the Company's initial Application." First Partial Stipulation, § III.7.

As part of First Partial Stipulation DEC and the Public Staff agreed to accept the Public Staff's adjustment with a modification to limit the incentives removed. This agreement is reflected in Section III.10 of the First Partial Stipulation, which provides that the Company's employee incentives should be adjusted to remove incentive pay related to EPS and TSR for the top levels of Company leadership.

Rate Case Expenses

In its Application the Company requested to amortize the incremental rate case costs incurred for this docket over a five-year period. Tr. vol. 11, 480. The Public Staff made an adjustment to remove the unamortized portion of rate case expense in rate base, reasoning that the amortization of rate case expense should reflect a normalization of the costs associated with the filing of a rate case, based on a historical average of the number of years between rate case filings. Tr. vol. 17, 259. Public Staff witness Boswell testified that that rate case expense does not rise to the level of being extraordinary in nature and therefore does not require rate base treatment. *Id.* In her rebuttal testimony witness McManeus testified that the Company opposed the Public Staff's adjustment and contended that if the Public Staff had used the historical average costs and number of years between rate case filings since 2013, the amortization amount would have been $1.5 million, which is higher than the Company's proposed amortization amount. Tr. vol. 11, 525. Because the costs are known and measurable, the Company argues that inclusion of the costs in rate base is appropriate because they are incremental costs that have been incurred and funded by investors prior to new rates becoming effective. *Id.* However, in the spirit of settlement, DEC and the Public Staff agreed to amortize the rate case expenses over a five-year period with the unamortized balance not included in rate base. First Partial Stipulation, § III.8.

Aviation Expenses

In its initial filing as updated by its February 14, 2020 supplemental filing, DEC removed 50% of the corporate aviation costs to account for flights that may not be related to provision of electric service. Tr. vol. 11, 480. The Public Staff made a further adjustment after investigating the aviation expenses charged to DEC during the test year. Tr. vol. 17, 252. Public Staff witness Boswell contended that based on her review of the flight logs, some of the flights appeared to be unrelated to the provision of utility services, and in other instances the costs of flights had been incorrectly allocated. *Id.* at 253. The Public Staff also removed the DEC-allocated portion of commercial international flights due to the Public Staff's determination that those flights were unrelated to the provision of utility service. *Id.*

In rebuttal Company witness McManeus explained that all of the costs of the corporate aircraft have been allocated in accordance with the Company's cost allocation manual and that the Company's proposal to remove 50% of the costs is consistent with the Commission's order in Sub 1142. Tr. vol. 11, 524. She also pointed out that the Public Staff's recommendation would result in recovery of less than 2% of corporate aviation costs. *Id.* For the purposes of settlement, the parties agreed to an adjustment that removes aviation expenses associated with international flights, in addition to the 50% of the Company's corporate aviation O&M expense removed in the Company's initial application. First Partial Stipulation, § III.9.

Sponsorships and Donations

Public Staff witness Boswell adjusted the Company's O&M expenses to remove amounts paid to the chambers of commerce, the North Carolina Chamber, and other donations, reasoning that they should be disallowed because they do not represent actual costs of providing electric service. Tr. vol. 17, 260. CBD/AV witness Ryan also recommended that Chamber of Commerce dues be disallowed. *Id.* at 489. In his rebuttal testimony Company witness Speros testified that Chambers of Commerce promote business and economic development, which in turn helps to retain and attract customers to DEC's service territory. Tr. vol. 15, 114. He explained that funds paid to Chambers of Commerce that are not specified as a donation or lobbying on the Chamber invoice are supporting business or economic development and are considered to be properly charged as a utility operating expense that should be included in the Company's cost of providing electric service to customers. *Id.* Nevertheless, as part of the First Partial Stipulation the Company agreed to accept the Public Staff's position on sponsorships and donations expense, and it removed amounts paid to the U.S. Chamber of Commerce and certain other expenses. First Partial Stipulation, § III.11.

Severance Costs

The Company made an adjustment to remove atypical severance and retention costs included in the test period and also requested to establish a regulatory asset to defer the North Carolina retail amount of $69.1 million of severance costs beginning when rates go in effect, to be amortized over a three-year period. Tr. vol. 17, 260-61. Public Staff witness Boswell adjusted the severance costs to reflect a normalized level over a three-year period, consistent with how the Public Staff has treated severance program costs in other utility rate cases. *Id.* at 261. In its rebuttal testimony the Company opposed the Public Staff's adjustment arguing that the adjustment only changed the proposed amortization period and did not calculate a normalized five-year level of severance expense, which would have been greater than the Company's proposed amortization amount. Tr. vol. 11, 525-26. Nevertheless, in the spirit of settlement, DEC and the Public Staff agreed that the severance expenses should be amortized over a three-year period, but the unamortized balance will not be included in rate base. First Partial Stipulation, § III.12.

Lobbying Expenses

With respect to lobbying expenses Public Staff witness Boswell noted that the Company assigned some lobbying expenses from the test year to below-the-line accounts and therefore that those costs were not included in the cost of service. Tr. vol. 17, 254. She further adjusted O&M expenses to remove what she characterized as additional lobbying costs, including O&M expenses that she believed were associated with stakeholder engagement, state government affairs, and federal affairs that were recorded above the line. *Id.* In his rebuttal testimony DEC witness Speros explained why the Company opposed this adjustment and disagreed with witness Boswell's characterization of these expenses. Tr. vol. 15, 108. Witness Speros testified that the amounts the Company has booked above the line align with an independent study performed by KPMG. *Id.*

In the spirit of settlement and in the context of the First Partial Stipulation as a whole, the Company and the Public Staff reached settlement on the lobbying expenses, and the Company agreed to accept the Public Staff's recommended adjustments to lobbying expenses. First Partial Stipulation, § III.13.

CBD/AV witness Ryan recommended that the Commission disallow recovery of costs related to DEC's support of Edison Electric Institute (EEI), Nuclear Energy Institute (NEI), Institute of Nuclear Power Operations (INPO), Utility Water Act Group (UWAG), and all Chambers of Commerce. Tr. vol. 17, 487-89. She contended that under the First Amendment of the U.S. Constitution individuals may not be compelled to provide financial support to entities that engage in political activities, regardless of how the funds are used, and that DEC has not demonstrated that the funds are not being used to support lobbying or other political activities. *Id.* at 489. Witness Speros disagreed with witness Ryan's recommended disallowance and explained that the Company already books any costs for these organizations that is related to lobbying, political activities, or contributions to a charitable foundation below the line. Tr. vol. 15, 112. According to witness Speros, these organizations are required to clearly identify the portion of dues that relate to these types of activities, and DEC automatically excludes these amounts from cost of service, as demonstrated in the Company's responses to data requests in this case. *Id.* at 112-13, 116. Moreover, he stated that the Public Staff conducted a full and complete audit of the Company's expenses and did not identify any improper amounts relating to dues paid to industry organizations like EEI, NEI, INPO, and UWAG. With respect to the portion of such dues that are recorded above the line, witness Speros testified that it is not reasonable to assume that all of these 34 organizations' activities constitute lobbying, or that because the organizations engage in some lobbying and political activities their other activities have no benefit to customers. *Id.* at 113. He explained that all of these entities are electric industry trade organizations that provide valuable resources to their member utilities such as training and testing for members' employees; information relating to cybersecurity initiatives, energy efficiency programs, and customer solutions; access to industry data; and breaking news on topics such as preparing for the coronavirus. *Id.* He concluded that customers benefit from the Company's participation in industry organizations as it keeps DEC current on industry trends, developments, innovative programs, and emerging safety issues, among other things. *Id.* at 113-14.

Board of Director Expenses

Witness Boswell made an adjustment to remove 50% of the expenses associated with the Board of Directors of Duke Energy that have been allocated to DEC. Tr. vol. 17, 250. Witness Boswell argued that the premise of this adjustment is closely linked to the premise of the adjustment the Public Staff made related to executive compensation in that the Board of Directors has a fiduciary duty to protect the interests of shareholders which may differ from the interests of ratepayers. *Id.* The Public Staff noted that it is appropriate for the shareholders of the larger electric utilities to bear a reasonable share of the costs of compensating the Board of Directors, as well as the cost of insurance for these individuals which has been utilized to defend the Board of Directors in suits brought by shareholders. *Id.* Witness Metzler explained that the Company is required to have a Board of Directors and that the costs of being an investor-owned utility, including Board costs, are in fact costs of service. Tr. vol. 11, 817. She argued that it is not fair or reasonable to penalize the Company for being an investor-owned utility with attendant requirements to that corporate structure. *Id.* As part of the First Partial Stipulation, the Company agreed to accept the Public Staff's recommended adjustments to the Board of Directors' expenses. First Partial Stipulation, § III.13.

Retired Hydro O&M Expenses

In May and December of 2018, the Company retired several hydro units at Rocky Creek, Great Falls, and 99 Islands. Tr. vol. 17, 260. Public Staff witness Boswell included an adjustment to remove all non-payroll related O&M costs related to these retired hydro units. *Id.* In her rebuttal testimony Company witness McManeus testified that the Company did not oppose this adjustment, and as part of the First Partial Stipulation the Company accepted the Public Staff's adjustment. Tr. vol. 11, 521; First Partial Stipulation, § III.13.

Credit Card Fees

In its Application DEC requests approval of a fee-free payment program for credit, debit, and ACH payment methods used by the Company's residential customers to pay their electric bills. Application at 11. Currently, customers are required to pay a $1.50 convenience fee, collected by a third-party vendor, for payments made by a credit card. To offer a fee-free payment program the Company proposes to pay these costs on behalf of its residential customers and recover the costs as part of its cost of service. Company witness McManeus described in her direct testimony the Company's proposal to adjust its O&M expense to adjust for credit card fee expenses, and she made an adjustment to reflect actual numbers of credit card transactions through January 2020. Tr. vol. 11, 482, 508.

Company witness Hatcher testified to the value and need for the customer-driven program. Tr. vol. 11, 921-22. Witness Hatcher explained that the requirement to pay a convenience fee when making a payment is one of the largest frustrations the Company's residential customers experience. He stated that the Company's Customer Service department routinely receives inquiries about no-cost electronic payment options as evidenced by the Company's monthly residential transaction surveys. According to witness Hatcher, customers have grown accustomed to paying for other products and services with a credit card or debit card without a separate, additional fee, and as customer expectations change and more payments are done electronically, utility companies are now offering fee-free payment programs for their residential customers for all methods of payment. Accordingly, witness Hatcher believes DEC residential customers will appreciate being able to use these payment methods with the Company the same way they can with other companies. As stated by witness Hatcher, Duke Energy has seen 14% average year over year growth in credit/debit transactions over the past several years, and with this change the Company expects the growth rate to double — so 28% more transactions in 2019 than in 2018. *Id.* at 921-23.

While no party contested the value or benefits of the fee-free credit card program for residential customers, Public Staff witness Boswell noted that the Company did not calculate any impacts to late payments or uncollectibles associated with the request to include credit card fees and has not removed the expenses related to the forms of payment that were utilized in the 2018 cost of service. Therefore, the Public Staff made an adjustment to remove the O&M expenses included in the cost of service for 2018 associated with the increase in credit card transactions from the 2018 to 2019 period, to avoid double-counting costs associated with the same payments. In addition, the Public Staff recommends the Company track the impact of the credit cards that no longer have a separate fee associated with the payment, on the late payment and uncollectible accounts, and report the quantitative impact in testimony in the Company's next general rate case. Tr. vol. 17, 255-56. In her rebuttal testimony Company witness McManeus testified that the Company partially agreed with the Public Staff's adjustment and accepted the concept of the Public Staff's adjustment to remove O&M expense associated with the increase in fee-free program transactions from 2018 to 2019. Tr. vol. 11, 520. However, witness McManeus testified that the Company has updated the calculation to reflect avoided transaction costs related to payment by check as reflected in McManeus Rebuttal Exhibit 1. *Id.* In his rebuttal testimony witness Hatcher testified that no party has contested the fee-free program. *Id.* at 928. In addition, in response to witness Boswell's recommendation that the Company track the impact of the fee-free program on the late payment and uncollectible accounts, he explained that the Company does not track the payment method with the customer's delinquency status at the time the payment is received. Instead, the Company blends all costs incurred for bill payment-related expenses, which is reflected in the cost of service; thus, any quantitative impact would be reflected in the future cost of service. Instead, the Company proposed to track and report the number of payments made by channel per year in the next general rate case. *Id.* As part of the First Partial Stipulation, the Public Staff agrees to the Company's rebuttal position on credit card fees. First Partial Stipulation, § III.14.

Advertising Expenses

Public Staff witness Boswell adjusted O&M expenses to exclude (1) items incorrectly booked to advertising, (2) advertising amounts for which the Company could not provide support, and (3) image and promotional advertising, consistent with prior Commission orders. Tr. vol. 17, 256. DEC witness Speros testified that regarding the first category where the costs were incorrectly booked to advertising, the costs were related to painting power poles, were inadvertently booked to the wrong FERC account, and are being corrected. Tr. vol. 15, 115. However, the Company opposed witness Boswell's adjustment because although the costs were booked to the wrong FERC account, the Company's position is that the costs are reasonable and prudent expenditures that should be recoverable in retail rates. *Id.* In her rebuttal testimony DEC witness McManeus testified that the Company does not oppose the remaining categories of advertising expense adjustments proposed by the Public Staff. Tr. vol. 11, 521. As part of the First Partial Stipulation, the Public Staff agreed to the Company's rebuttal position on advertising expenses. First Partial Stipulation, § III.14.

May 2020 Updates

On July 2, 2020, the Company filed second supplemental direct testimony and exhibits updating certain material pro forma adjustments through May 31, 2020 (May 2020 Updates). The Company updated revenue requirements through May 2020 for the following pro forma adjustments: customer growth, post-test year additions to plant in service, accumulated depreciation, depreciation expense, property taxes, O&M nonlabor expenses, O&M labor expenses, merger related costs, interest synchronization, cash working capital, and an adjustment to update and remove storm costs for securitization. Tr. vol. 11, 575-76. Though the Public Staff initially opposed the May 2020 Updates, DEC and the Public Staff eventually reached agreement regarding the consideration of the updates in the Second Partial Stipulation and agreed to include the adjustments, pending and subject to the Public Staff's audit of the updates. Second Partial Stipulation, §§ III.J, IV.A. DEC and the Public Staff also agreed to include updates for benefits and executive compensation. *Id.,* § III.J. Finally, DEC and the Public Staff agreed to limit the updates on revenues to 75% of the difference between the May 2020 Updates and the Company's January 2020 update to recognize the uncertainty regarding the effects of COVID-19, and the 75% limitation is applicable only if the net effect of the updates on revenues is a revenue requirement increase. *Id.*

After completing the aforementioned audit, on September 8, 2020, Public Staff witness Boswell filed second supplemental and settlement testimony and exhibits updating and revising the Public Staff's calculation of its recommended revenue requirement, including the impacts of the Second Partial Stipulation and the accompanying review of the Company's May 2020 Updates. The Public Staff reviewed the Company's proposed updates to net plant, depreciation expense and accumulated depreciation, new depreciation rates, and revenues and related expenses (weather, and customer growth and usage). The Public Staff recommended certain adjustments to these items, and also recommended an adjustment to update certain employee benefits, weather, and customer growth and usage, which adjustments were reflected in Boswell Second Supplemental and Stipulation Exhibit 1. Tr. vol. 22, 76-77. The adjustments for benefits, weather, and customer growth and usage totaled $953,000, exclusive of the impact on cash working capital.

Lead-Lag Study

The Company submitted a new Lead-Lag Study as Speros Exhibit 3. DEC subsequently revised Speros Exhibit 3 as part of the supplemental testimony of DEC witness Speros. In her direct testimony Public Staff witness Boswell proposed adjustments to cash working capital based on the Public Staff's review of the Lead-Lag Study. Witness Speros testified that the Company agreed with the Public Staff's adjustments to cash working capital and noted that the adjustments are consistent with the changes he described in his supplemental testimony that are included in the revised Lead-Lag Study. Tr. vol. 15, 107.

Weather Normalization, Customer Growth and Usage

DEC witness Pirro testified that he provided the retail sales and number of customers to DEC witness McManeus for use in calculating the pro forma adjustment to growth in customers. Tr. vol. 12, 237. He explained that to arrive at the appropriate number of customers served and the attendant annualized sales levels at the end of the test period, the Company used a combination of regression analysis and a customer-by-customer approach. *Id.* In his supplemental direct testimony witness Pirro testified that the Company had adjusted customer growth to reflect actual customer growth data and weather impacts through January 2020. He also testified that the adjustment to normalize for weather had been updated to incorporate additional months of actual sales and weather data through January 2020, and the average cents/kWh for the residential class has been revised to remove the Basic Facilities Charge (BFC) component. *Id.* at 258-59.

Public Staff witness Saillor proposed modifications to the Company's customer growth, weather normalization, and change in usage adjustments. Tr. vol. 16, 640. In terms of weather normalization, witness Saillor testified that monthly kWh adjustments are determined to weather normalize test period sales for the residential, general, and industrial rate classes. He explained that the revenue adjustment is calculated by multiplying the total rate class kWh adjustment by the average customer class rates based on annualized revenues divided by per book sales. He recommended that the revenues generated from per-bill basic facilities charges be removed because the weather effect does not change the number of bills rendered during the test period. He also summed the monthly North Carolina retail kWh weather adjustments updated through November 2019, as provided to the Public Staff by DEC, for each month of the test period for each customer class. He explained that each monthly adjustment is based on the monthly system weather adjustment and each month's North Carolina sales to system sales ratio. This is in place of the method used in the Form E-1, Item 10 worksheet NC-0301 where the North Carolina retail kWh weather adjustment per class is calculated by multiplying the test period system kWh weather adjustment times the annual North Carolina retail to system sales ratio. Witness Saillor explained that he believes that summing the monthly North Carolinas retail kWh adjustments more accurately reflects the normal weather adjustment being represented by DEC. *Id.* at 641-45.

To annualize revenues for customer growth and change in usage witness Saillor proposed modifications to the methodology proposed by DEC. *Id.* at 647. He revised DEC's customer-by-customer approach for calculating the average monthly usage for each new general and industrial customer added to the system during the test period by summing the 12 months of billing data following the initial month of service and dividing that value by 12, which he believes results in a more precise representation of the customer's average monthly usage. Witness Saillor further revised the customer-by-customer approach by removing the initial month of service from the average usage calculation for new general and industrial customers added to the system after the end of the test period. For change in usage calculations, witness Saillor removed the BFC revenues reasoning that the increase or decrease in usage would not change the number of bills included in annualized revenue. For the lighting rate class, witness Saillor removed the change in usage revenue adjustment under the rationale that lighting accounts are billed on a per-light basis, and revenues for the lighting class would not change due to changes in usage. Witness Saillor also calculated a change in usage adjustment for the general and industrial rate classes based on the difference in the monthly average weather-normalized usage per customer. *Id.* at 647-49.

In his supplemental testimony Public Staff witness Saillor testified that the Company agreed with his proposed modifications for weather, customer growth, and change in usage. Witness Saillor explained that he made one change to DEC's method for updating the change in the number of test period bills for the general and industrial rate classes by instead finding the difference between the number of bills added to the test period for new accounts and the number of bills removed from the test period for closed accounts from DEC's customer-by-customer approach for calculating customer growth. *Id.* at 653.

As part of the First Partial Stipulation the Company agreed to accept the Public Staff's updated recommended adjustments to weather normalization, growth and usage as reflected in Boswell Supplemental and Stipulation Exhibit 1. First Partial Stipulation, § III.15. Subsequently, in his second supplemental direct testimony witness Pirro testified that the Company updated its customer growth adjustment through May 31, 2020, to incorporate certain known and measurable changes. He explained that the updated customer growth adjustment reflects a significant reduction in the Company's load and associated revenues as a result of many commercial and industrial customers and schools and colleges scaling back operations, as well as an increase in residential usage, during the COVID-19 pandemic. Tr. vol. 12, 273-74). In support of the updated customer growth adjustment witness Pirro testified that reflecting these changes closer in time to the rescheduled hearing will result in a more accurate depiction of the Company's load forecast and customer usage. *Id.* at 274. As noted above, DEC and the Public Staff eventually reached agreement regarding the May 2020 Updates and agreed to include the adjustments, pending and subject to the Public Staff's audit of the updates, and also subject to a limit of the updates on revenues to 75% of the difference between the May 2020 Updates and the Company's January 2020 update to recognize the uncertainty regarding the effects of COVID-19 if the net effect of the updates on revenues is a revenue requirement increase. Witness Pirro filed Pirro Second Settlement Exhibit 4 to reflect the revised revenue requirement resulting from the Second Partial Stipulation and the Company's position on unsettled items.

Non-Labor O&M

The Company adjusted annual non-labor, non-fuel O&M costs to reflect the increase in costs during the test year that occurred due to the effect of inflation as of December 31, 2018. Public Staff witness Boswell adjusted the Company's inflation adjustment to reflect the Public Staff's adjustment to include variable O&M expenses for changes in customer growth and the removal of aviation expenses, Board of Directors expenses, outside services expenses, uncollectibles, sponsorships and donations, and advertising. In rebuttal testimony Company witness McManeus did not oppose the adjustment. Subsequently, in the Second Partial Stipulation the Public Staff and the Company agreed to the allocation methodology to apply to the expenses, as well as to reflect the inflation factor through May 31, 2020, to coordinate with other items updated through that same point in time. The specific updated Public Staff adjustments discussed in witness Boswell's testimony to which the Company agrees are as follows.

Plant in Service and Accumulated Depreciation

Public Staff witness Boswell updated net plant for known and actual changes to depreciation expense and non-generation plant retirements recorded between the end of the test year and May 31, 2020. Witness Boswell also included adjustments recommended by Public Staff witness Metz removing costs related to the Lincoln CT Plant and the Company's Project Focal Point. The impact of the removal of costs associated with the Lincoln CT Plant and Project Focal Point, which were each part of the Public Staff's adjustments to the update of plant, depreciation expense, and accumulated depreciation, are included in the unsettled update to plant and accumulated depreciation as of May 31, 2020, listed on Schedule 1, Line 6 of Boswell Second Supplemental and Stipulation Exhibit 1. Although the Public Staff and the Company agree the items should be removed from plant in service and accumulated depreciation, the item remains unsettled until the Commission determines the appropriate depreciation rates, which are included in the calculation of the adjustment. The Company agreed that these adjustments should be included in the calculation of the final revenue requirement determined in the present case.

Updated Revenues

Public Staff witness Boswell updated the energy-related non-fuel variable O&M expense per kWh rate and the annual customer-related variable O&M expense per kWh rate to reflect the calculations to include amounts determined pursuant to the SCP allocation methodology. Furthermore, witness Boswell included the fuel factors recently approved by the Commission in Docket No. E-7, Sub 1228 in the calculation of annualized revenues and fuel expense, including growth, usage, and weather normalization impacts. The Company agreed with this adjustment. *Id.* at 81.

Benefits

Public Staff witness Boswell updated the benefits related to OPEB, pension, FASB 112, and non-qualified pensions to reflect the updated 2020 actuarial amounts that became available after the January 31, 2020 update period. The Company agreed with this adjustment. *Id.* at 81-82.

Clemson CHP

In his supplemental testimony Public Staff witness Metz recommended that capital costs in the amount of $50.3 million associated with the Company's Clemson CHP Project be removed from rate base. Tr. vol. 16, 680, 684. Witness Metz discussed the mechanics of combined heat and power (CHP) technology and described his understanding of the location, size, and purpose of the CHP Project as providing thermal energy (steam) service for the Clemson University (University) campus pursuant to a contract between the Company and the University (Steam Agreement). *Id.* at 681-83. He asserted that the per kW cost of approximately $4,800 for the CHP Project was extraordinarily high as compared to combined cycle (CC) plants and to combustion turbine (CT) costs used in the Company's avoided cost calculations *Id.* at 684. He also expressed concerns with other provisions of the Steam Agreement and questioned the need for the project. *Id.* at 685-709. Public Staff witness Boswell in her supplemental and settlement testimony incorporated an adjustment to remove the CHP Project from plant in service and made corresponding adjustments to depreciation expense and accumulated depreciation based on witness Metz's recommendation. Tr. vol. 17, 279.

In his rebuttal testimony Company witness Kuznar described CHP systems, including their efficiency and environmental benefits. He discussed the Company's overall strategy of exploring CHP as an option to diversify its regulated generation mix with distributed, smaller assets that can economically meet future customer demand as well as reduce transmission and distribution losses and improve reliability. Tr. vol. 11, 827-28. Witness Kuznar also clarified that the North Carolina retail share of the CHP Project was $33.9 million. *Id.* at 833. Witness Kuznar testified that the Public Staff's recommended disallowance disregarded the benefits that North Carolina customers will receive from the

Company's investment in the CHP Project. *Id.* at 826, 831. He also disagreed with witness Metz that the cost for the CHP Project was too high. *Id.* at 834-35.

In her supplemental rebuttal testimony witness Hager testified that the Public Staff's position that the costs of the CHP Project should not be allocated to North Carolina retail customers because, in part, the electricity may never reach DEC's transmission system is inconsistent with sound cost allocation principles. Witness Hager explained that physical location does not govern whether a generation resource is a system asset: if a generation resource is available to serve system load requirements, it is a system asset and is generally allocated to all jurisdictions across the system. Tr. vol. 12, 225.

Section III.K of the Second Partial Stipulation provides that "[t]he Company accepts the Public Staff's recommended system disallowance of $19.1 million for the Clemson Combined Heat and Power Project."

Company witness McManeus, tr. vol. 11, 582, Public Staff witness Boswell, tr. vol. 17, 284-86, and Public Staff witness McLawhorn, tr. vol. 18, 255, supported the provision for the disallowance for the CHP Project through their testimony in support of the Second Partial Stipulation. Witness Boswell presented the final $10 million adjustment to North Carolina retail in her Second Supplemental and Stipulation Exhibit 1, Schedule 2-1(g). Tr. vol. 22, 77-78.

Deferred Non-ARO Environmental Costs

Public Staff witness Maness testified that pursuant to the Commission's approval of the 2016 request for deferral filed in Docket No. E-7, Sub 1110, the Company is proposing to defer and amortize certain depreciation and return requirements related to certain capital projects placed into plant in service since its most recent rate proceeding. Tr. vol. 20, 519. He explained that these projects are not classified by the Company as legal obligations associated with the retirement of coal ash facilities or the generating plants with which those facilities are associated; instead, they are intended to address coal ash issues related to the continuing operation of the applicable generating plants. Although they are not part of the legal obligation that gives rise to DEC's coal ash ARO, the Company and Public Staff agree that these costs are eligible for deferral pursuant to the terms of the Sub 1110 deferral accounting request, because they are needed to fulfill the Company's responsibilities under CAMA and the EPA's CCR Rule. However, witness Maness testified that although he does not oppose deferral of the capital (return and depreciation) costs of the projects in this case, he does not agree with the five-year period proposed by the Company over which to amortize the deferred costs. He instead recommends an amortization period of ten years, which would lower the revenue requirement and substantially ease the annual impact of the deferral and amortization on the ratepayer, noting that the reduction would not directly harm the Company in that the unamortized amount would earn a return through being included in rate base. *Id.* at 519-22.

In rebuttal DEC witness McManeus testified that the Company does not agree with witness Maness's recommendation to increase the amortization period for non-ARO related deferred capital expenditures. Tr. vol. 11, 540. She explained that the Company considered annual rate impacts in its recommendation of the five-year amortization and considered the Commission's decision in the 2018 DEC Rate Order in arriving at its proposed amortization period. *Id.* Nevertheless, in the spirit of settlement DEC and the Public Staff have agreed to amortize deferred non-ARO environmental costs over an eight-year period. Second Partial Stipulation, § III.L.

Discussion and Conclusions

Based on the foregoing and the record, the Commission concludes that the provisions of the Public Staff First and Second Partial Stipulations on cost-of-service adjustments aptly demonstrate the efforts of the stipulating parties to reach compromise on many details of DEC's operating costs. Auditing a public utility's accounting records and formulating a position on the many cost of service items is a labor intensive and tedious job. The Commission appreciates the work of the Public Staff and the stipulating parties for coming together and working out many of these accounting issues. The Commission determines that the cost adjustment provisions are the result of give-and-take negotiations, and therefore the Commission places great weight on the cost adjustment provisions of Public Staff stipulations. As a result, the Commission concludes that the stipulated adjustments discussed herein are just and reasonable, and the portions of the Public Staff First and Second Stipulations on cost-of-service adjustments should be approved.

With regard to the issue of lobbying expenses raised by CBD/AV, the Commission agrees that organizations such as EEI, NEI, INPO, and UWAG engage in non-lobbying and non-political activities that benefit customers, and the Commission finds that DEC's practice of excluding the portions of dues paid to trade groups that relate to lobbying or political activities is consistent with the Commission's guidance on this issue. In addition, the Commission gives significant weight to the fact that the Public Staff found no reason to disallow the portions of dues paid by the Company to EEI, NEI, INPO, and UWAG included in the Company's cost of service.

Further, in its Order Dismissing Petition in Part, Granting Petition to Intervene, Joining Necessary Parties, and Requesting Comments in Docket No. M-100, Sub 150 issued on August 29, 2019 (Lobbying Rulemaking Order), the Commission rejected the constitutional arguments asserted by CBD/AV. Lobbying Rulemaking Order at 3-6. Further, the Commission stated :

> The utilities' memberships in trade groups such as EEI and EPRI for research, development of best business practices, and other educational purposes can be well worth the dues paid, both for the utilities and their ratepayers. But the cost of lobbying activities by such organizations, for legislative advocacy often on a national level that may have little or nothing to do with North Carolina's public interest, is not a cost that should be borne by North Carolina's ratepayers.

> Therefore, the Commission finds good cause to request comments on the following proposed additional definition to Rule R12-12, and the underlined additions to Rules R1212(d) and R12-13(a).

Id. at 14-15.

The Lobbying Rulemaking Order set forth extensive proposed definitions and potential restrictions on lobbying costs and charitable contributions, among others. As noted, the Commission invited comments on these proposed guidelines. In response, the Commission has received extensive comments. The Commission is weighing the comments, statutes, rules of other jurisdictions, and other factors that bear on the recovery of costs associated with lobbying, trade organization membership, and similar activities and will issue its findings and decision on that issue in that proceeding.

Lastly, the Commission finds and concludes that the adjustment to the Company's revenue requirement of $19.1 million on a system basis for the CHP Project as reflected in the Second Partial Stipulation and in witness Boswell's Second Supplemental and Stipulation Exhibit 1, Schedule 2-1(g), reflects a compromise among the parties in this proceeding, and the Commission finds that compromise reasonable and appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 37–41

Deferral of Grid Improvement Plan Capital Costs

The evidence supporting these findings of fact is found in the verified Application and Form E-1; the stipulations entered into between DEC and several parties; the testimony and exhibits of DEC witnesses McManeus, Young, and Oliver, Public Staff witnesses David Williamson, Tommy Williamson, Maness, Thomas, and McLawhorn, NCSEA/NCJC et al. witnesses Stephens and Alvarez, CIGFUR witness Phillips, CUCA witness O'Donnell, Harris Teeter witness Bieber, NC WARN witness Powers, Tech Customers witness Strunk, and Vote Solar witnesses Nostrand and Fitch; and the entire record in this proceeding.

Summary of the Evidence

DEC Direct Testimony

DEC witness Jane McManeus explained that the Company requests an accounting order that would allow DEC to defer its GIP capital costs starting with costs incurred in January 2020. She asserted that DEC's GIP costs meet the Commission's test for deferral because they are not simple, regularly occurring, inconsequential investments but rather are major nonroutine investments that produce substantial customer benefits. She testified that absent deferral, if DEC pursued its proposed GIP spending, the Company would experience a significant adverse earnings impact that would grow to over 100 basis points by 2022.

DEC witness Steven Young testified that investors are looking for modernized mechanisms that allow more timely recovery of investments. He stated that "now most of our investments are smaller in nature. They go in service quicker." He stated that the Company must absorb the related depreciation, O&M and interest expense, and the deferral mechanism helps to address the lag in both cash and in earnings. Tr. vol. 3, 49-50.

DEC witness Jay Oliver testified that DEC had developed its GIP to respond to these seven "megatrends":

(1) Population and business growth continue in North Carolina and is concentrated in urban and suburban areas.
(2) Distributed energy technology is advancing rapidly; there are new kinds of load and resources impacting the grid.
(3) New technologies offer new capabilities and functions for the grid.
(4) Customer expectations have changed.
(5) There are more environmental commitments at every level of government.
(6) Major weather events are more numerous and more severe.
(7) Physical and cyber threats to the grid are more sophisticated and are increasing.

Witness Oliver stated that DEC seeks deferral accounting for $1.3 billion in spending on the following GIP programs during 2020 through 2022: (1) Self-Optimizing Grid (SOG), (2) Integrated Volt/VAR Control (IVVC), (3) Transmission Hardening and Resiliency, (4) Targeted Undergrounding, (5)Distribution Transformer Retrofit, (6) Long Duration Interruptions/High Impact Sites, (7) Transmission Transformer Bank Replacement, (8) Oil Breaker Replacements, (9) Enterprise Communications, (10) Distribution Automation, (11) Transmission System Intelligence, (12) Enterprise Applications, (13) Integrated System Operations Planning (ISOP), (14) Distributed Energy Resource (DER) Dispatch Enterprise Tool, (15) Power Electronics for Volt/VAR Control, and (16) Physical and Cyber Security.

Public Staff Direct Testimony

Public Staff witnesses David Williamson and Tommy Williamson testified that DEC is currently working on 12 of the GIP programs and that it had spent about $52 million on the programs during the 2018 test year on a system basis, and another $273 million in 2019, again on a system basis. The Public Staff reviewed DEC's proposed GIP to identify programs that are unique and extraordinary and hence appropriate to consider for deferral. They sought to identify those programs that would bring the grid up to new standards of operation and reliability. The Public Staff rejected for deferral those programs that are the kinds of activities that DEC engages in or should engage in on a routine and continuous basis. The Public Staff concluded that the following GIP programs are extraordinary: (1) the automation and control portion of the SOG, (2) the advanced distribution management system portion of the SOG, (3) IVVC, (4) Transmission System Intelligence, (5) the Underground System Automation portion of Distribution Automation, and (6) ISOP. The Public Staff believes these initiatives are transformative and would provide significant new capabilities to the grid.

Public Staff witness Maness testified that DEC intends to spend about $445 million on the GIP programs that witnesses Williamsons identified as being extraordinary. He stated that absent deferral, the return on equity impact of these programs would average 20.33 basis points over the three years, and under normal circumstances the Public Staff would not recommend deferral of an investment with a basis point impact that is so small. He stated that in this case, however, the Public Staff took notice of the Commission's order from DEC's last rate case, Sub 1146. Witness Maness asserted that in the 2018 DEC Rate Order the Commission appeared willing to be lenient regarding the magnitude of costs or financial impacts necessary to justify deferral for grid improvement investments. For that reason he did not object to the Commission allowing deferral of the capital costs of the six programs identified by witnesses Williamsons, as long as the Commission determined that the estimated basis point impact falls within the range of leniency that the Commission is willing to grant. Witness Maness further stated that such a deferral should be considered specific to this case and not precedential with regard to any future general rate case proceeding or deferral request.

Public Staff witness Thomas reviewed the cost-benefit analyses that DEC provided for some of the GIP programs. While he did not recommend rejection of any of the programs, he did express concern that a majority of the benefits identified in DEC's cost-benefit analyses were estimates of the financial benefits customers would receive by avoiding power outages. He testified that DEC relied on a Lawrence Berkeley National Laboratory (LBNL) report to estimate the financial value of these benefits. Witness Thomas testified that 87% of the benefits of DEC's GIP were customer reliability benefits, and about 97% of those benefits would accrue to commercial and industrial customers. Witness Thomas testified that DEC's cost estimates for the GIP programs were of a high-level nature, and actual costs could vary widely from such estimates. He pointed out other concerns with DEC's cost-benefit analyses but ultimately did not recommend rejection of any of them. He recommended that GIP expenditures should be tracked and reported, that DEC should perform cost-benefit analyses for additional GIP programs, that DEC should file sensitivity analyses of its cost-benefit analyses that include cost variations, that DEC should consider conducting a study to more accurately reflect its customers' outage costs, and that DEC should remove or modify benefits in its analyses, including long-term reliability benefits, CO_2 emission savings, avoided capacity planning margin requirements gross-up, and avoided capacity in years when no capacity is needed. In addition, Thomas recommended that DEC revise its analysis for the Transmission Hardening and Resiliency program to assign reliability benefits to customer classes. He stated that DEC should revise the SOG cost-benefit analysis to include the effect of momentary outages and the expected reduction in vegetation-related outages from increased vegetation management. Thomas said DEC should consider how GIP investments would impact other costs, such as inventories, and that DEC and the Commission should consider changing the allocation of GIP costs among customer classes.

Public Staff witness McLawhorn stated that the benefits derived from some of the GIP transmission and distribution assets are disproportionally related to the way the GIP transmission and distribution plant is allocated. He believes this area of cost allocation deserves further study.

NCJC et al. Direct Testimony

Witness Stephens reviewed DEC's GIP, including its cost-benefit analyses. He identified deficiencies in some and a lack of justification for others. He recommended that the Commission reject DEC's GIP and establish a separate proceeding for developing a new GIP plan and budget. He identified eight of DEC's GIP programs that merit approval, with conditions, because they represent standard industry practice; they consist of software that is needed to optimize grid assets, operations, or cyber security; they are likely to deliver benefits to ratepayers in excess of costs; or they are critical to provide stakeholders' value that cannot be otherwise secured. These eight programs are: (1) IVVC; (2) the flood and animal mitigation portions of Transmission Hardening and Restoration; (3) Long Duration Interruptions/High Impact Sites; (4) foundational software including Enterprise Applications, ISOP, and DER Dispatch; (5) Cyber Security (excluding substation physical security); (6) Enterprise Communications (excluding mission critical voice and data network); (7) Power Electronics for Volt/VAR Control; and (8) Automated Distribution Management System.

Witness Stephens stated that the SOG program should be approved but at a reduced level to focus on circuits that would experience the greatest benefit. As to the Transmission Hardening and Resiliency program, he stated that the entire budget should focus on projects to accommodate more distributed energy resources.

Witness Stephens testified that the Commission should reject the following programs because they are not generally cost-effective: (1) Targeted Undergrounding, (2) Distribution Transformer Retrofits, (3) Transformer Bank Replacements, (4) Oil-filled Breaker Replacements, and (5) Substation Physical Security. Witness Stephens recommended that the Commission require on-going performance measurement for DEC's GIP initiatives as well as cost caps and operating audits.

In addition, witness Stephens recommended that the Commission reject the Mission Critical Voice and Data Network Development programs because DEC completed no make-versus-buy evaluation of alternatives to its own $160 million proposal to build proprietary voice and data networks. Similarly, Stephens said DEC provided no cost-benefit analyses for its Distribution Automation and Transmission System Intelligence programs.

Witness Paul Alvarez criticized DEC's reliance on the LBNL report for estimating outage costs; he said the report is based on old data that is geographically biased and biased toward manufacturing and retail businesses that have the highest outage costs of all commercial and industrial (C&I) segments. Further, the surveys used to collect outage cost data did not consistently address the availability of back-up generators and uninterruptible power supply systems. Witness Alvarez asserted that DEC over-estimated the GIP's benefits by overstating the number of outages being avoided by the programs, then by overstating the economic benefits of those avoided outages, and finally by using those overstated primary benefits as inputs to the IMPLAN software, which estimates the secondary benefit. Further, he contended that DEC did not estimate the detrimental impacts on North Carolina's economy of the significant rate increases that the GIP would generate. He asserted that the GIP would cause a 4.1% rate increase, that residential customers would likely be allocated about 48% of the costs, and that they would pay at least $7.85 for every $1 in benefits that the receive. On the other hand, he asserted that DEC's shareholders would likely earn $2.6 billion in return on equity over 30 years, or $1.2 billion in present value terms, from its GIP investments. He testified that DEC's GIP will ultimately cost ratepayers $8.7 billion over 30 years, or $3.5 billion in present value terms. He also asserted that the GIP presents an asymmetrical risk profile, one in which ratepayers take all the risk for benefit delivery and cost overruns, while shareholders earn a rate of return under all scenarios. He recommended that the Commission reject DEC's GIP and its request for deferral accounting and establish a proceeding to develop a transparent, stakeholder-engaged distribution planning and capital budgeting process.

CBD/AV Direct Testimony

Witness Wolf advocated for the presentation of all costs and benefits in DEC's GIP analyses; transparency of regionally appropriate distributed energy resources and opportunities for them to interconnect; increased customer access to their usage data and sources of energy; facilitation of greater use of storage, demand-side resources, grid operation/management devices, and bi-directional flow of power; performance measurement to ensure benefits are delivered; and increased deployment of renewable energy.

Witness Ryan recommended that the Commission reject DEC's request for deferral of GIP costs until after the 2020 IRP proceeding. She stated that DEC failed to explain how its GIP programs address the identified megatrends and that DEC did not disclose how burdensome its GIP expenditures would be for ratepayers.

CIGFUR Direct Testimony

Witness Phillips testified that there is no compelling evidence demonstrating that grid improvements warrant a departure from standard ratemaking practices. Further, he asserted that DEC's plan would shift regulatory risk from its investors to customers as well as allow DEC to pursue single-issue ratemaking. He testified that the deferral, if approved, could eliminate DEC's incentive to prudently manage costs between rate cases, and GIP costs are not volatile or unpredictable. Witness Phillips stated that if the deferral is approved, DEC's allowed ROE should be reduced to reflect the reduced business risk that its investors will face.

CUCA Direct Testimony

Witness O'Donnell testified that DEC's proposed grid expenditures are too expensive and lack customer support. He stated that many of the programs lack cost-benefit analyses to prove that they are beneficial and should therefore be disallowed. He stated that the Commission should only allow recovery of GIP programs costs where promised reliability benefits are achieved.

Witness O'Donnell testified that regulated utilities have an incentive to build plant, and that DEC offered no performance guarantees. He asserted that DEC intends to pursue its Power Forward grid initiative, of which GIP is a part, and that this $13 billion ten-year grid modernization effort will cause massive rate increases. He asserted that a typical industrial customer would pay $12 million more over ten years due to DEC's GIP investments.

Harris Teeter Direct Testimony

Witness Bieber recommended that the Commission reject DEC's proposal to defer GIP costs. He stated that deferral is unnecessary and would amount to single-issue ratemaking. Witness Bieber testified that DEC's GIP costs do not appear to be volatile or outside the Company's control, and they should be considered in the context of general rate cases.

NC WARN Direct Testimony

Witness Powers recommended that the Commission reject DEC's GIP proposal, stating that the stakeholder workshops that DEC hosted were essentially sales presentations. He stated that the high cost of the GIP is such that additional rigorous review is needed to protect ratepayers. He testified that the GIP presumes that there is only one pathway to grid modernization and that other alternatives should be considered. For example, installing battery storage in residences would be a less costly way to improve reliability than the Targeted Undergrounding program that DEC proposes.

Tech Customers Direct Testimony

Witness Strunk testified that DEC has not justified the use of deferral accounting for its GIP and failed to justify treating those investments differently from other infrastructure investments. He stated that DEC used speculative, indirect benefits to legitimize its GIP expenditures. Witness Strunk testified that DEC's GIP is premature and should await the results of its ISOP planning process.

Witness Strunk testified that the two-pronged test used by the Commission to determine whether to approve deferral requests is the correct approach. He stated that the Commission should consider whether the costs in question are unusual or extraordinary and whether, absent deferral, the costs would have a material impact on the utility's financial condition. He said that DEC did not prove its case that the deferral request meets either of the prongs. He said there is overlap between DEC's regular transmission and distribution spending and the GIP, and DEC did not explain how it would differentiate between what costs are to be deferred and what costs are not.

Witness Strunk testified that the megatrends driving DEC's GIP are not likely temporary, and they are nothing new. He described them as systemic influencers that are the opposite of unusual and extraordinary.

Witness Strunk responded to DEC witness McManeus' testimony about the financial impact of the deferral, the testimony in which she said that absent the deferral DEC's earnings degradation would grow to more than 100 basis points by 2022. Witness Strunk stated that this assertion is flawed in two ways. First, it assumes that DEC would invest the same amount over the same time frame if GIP deferral were denied. He testified that this is contradicted by witness Oliver, who suggested that DEC would spend less on GIP without the deferral. In addition, witness Strunk said that witness McManeus' analysis looks at the GIP investments in isolation, without considering how other elements of DEC's spending and balance sheet will evolve. According to witness Strunk, witness McManeus' analysis failed to consider the natural reduction in rate base that DEC's asset portfolio experiences over time due to depreciation.

Witness Strunk criticized DEC's GIP cost-benefit analyses because DEC did not incorporate customer preferences for lower electric rates. Similarly, DEC did not consider the negative effects on the economy of raising electric rates. He stated that the $7 billion of indirect benefits that DEC ascribed to its GIP appear to be speculative.

Vote Solar Direct Testimony

Witnesses Nostrand and Fitch testified that DEC's GIP does not assess or respond to climate-related risks, and it does not adhere to grid modernization best practices. They recommended that the Commission: (1) direct DEC to assess and manage climate-related risks across its operations and assets, (2) make clear that it will apply this standard to GIP investments, (3) direct DEC to participate in DEQ stakeholder processes around grid modernization, and integrate data, findings, and recommendations into its GIP, (4) require DEC to file a report identifying gaps in knowledge that need to be filled through further collaboration, (5) require DEC to develop a GIP through an integrated distribution planning process, and (6) if GIP deferral is allowed, impose performance-based conditions on the recovery of the deferred amounts.

DEC Rebuttal Testimony

Witness Oliver stated that none of the intervenor witnesses credibly disputed the megatrends that are driving the need for the GIP. Tr. vol. 11, 641.

As to the Public Staff's assertion that some GIP programs do not meet the definition of grid modernization, witness Oliver argued that each program within the GIP seeks to bring the current grid up to new standards of operation or reliability. He then used the same matrix and methodology for analyzing GIP programs that the Public Staff had developed, scored the programs higher for some attributes, and concluded that these programs should be added to the Public Staff's list of "extraordinary" programs:

(1) SOG Capacity and Connectivity;
(2) Transmission Hardening and Resiliency – 44-kV System Upgrade Subprogram;
(3) Distribution Automation (the Underground System Automation subprogram was already included in the Public Staff's list);
(4) Power Electronics;

(5) Distributed Energy Resource Dispatch Tool; and
(6) Cyber Security.

Where the Public Staff's list of six "extraordinary" programs totals $492 million in capital spending from 2020-2022, witness Oliver's six programs would add $433 million to that amount, for a total of $925 million. As to the other programs, witness Oliver stated that the Public Staff's evaluation method is one rational approach, but it is not the only way to evaluate programs. Witness Oliver asserted that all of DEC's GIP initiatives meet the definition of grid modernization, and all of their costs should be eligible for deferral.

The most expensive GIP program that the Public Staff disputed is SOG at $420 million in capital over three years. Witness Oliver stated that SOG is an example of a GIP project that addresses all of the megatrends, not just reliability. He said that when wide-spread, privately owned roof-top solar is adopted, a dynamic, automated, capacity-enabled two-way power flow grid is an essential component to be in place. During lightly loaded shoulder seasons SOG would allow excess DER energy to be routed to adjacent neighborhoods for use, maximizing its value and reducing line losses.

Witness Oliver asserted that SOG will allow DEC to defer capacity. He stated further that DEC plans to deploy SOG on circuits where it will have the most benefit. Since that deployment will increase DEC's efficiency when responding to outages, it will benefit all customers. Witness Oliver disagreed with Public Staff witness Thomas's assertion that SOG will result in an increased number of momentary outages.

Witness Oliver responded to witness Thomas's concern that SOG benefits are overstated because DEC failed to consider the reduced number of vegetation-related outages that will occur due to DEC's tree trimming plans. Witness Oliver stated that DEC's increased tree trimming would reduce SOG benefits by only about 2%. In addition, DEC's cost-benefit analysis for SOG did not include any benefits for improving reliability on major event days. He said that SOG is a "no regrets" investment that provides significant value for customers in multiple ways.

As to the 44-kV System Upgrade program, witness Oliver stated that this effort would protect the 44-kV system from extreme weather and begin to pave the way for more DER interconnections. Witness Oliver responded to witness Alvarez's assertion that DEC's GIP cost-benefit analyses contain $425 million in capital spending that is not included in DEC's three-year capital spending. Witness Oliver stated that it is not accurate to compare the capital budget spending plan in his Exhibit 10 to the costs in DEC's cost-benefit analyses because they serve different purposes. He stated that some of the cost-benefit analyses are for projects or programs that start in the 2020–2022 period but continue into 2023 and beyond.

Oliver stated that the majority of the $1.1 billion in software and communications replacement costs identified by witness Alvarez are justified under cost-effective guidelines instead of via a cost-benefit analysis. He said that there is no need to evaluate all programs over the same lifecycle.

As to witness Alvarez's assertions that DEC did not consider alternatives for its $160 million in communications network investments, witness Oliver said DEC followed documented enterprise supply chain processes, including requests for information and requests for proposals, to evaluate alternatives. He said that, where appropriate, considering the cost, security, speed to deploy and level of service required, external carriers provide services to DEC's networks. He testified that core data network requirements exceed the current capabilities that third-party cellular providers can provide given their bandwidth limitations. Witness Oliver stated that for the Land Mobile Radio program, alternative services were considered, and bidders were eliminated because of their inability to meet requirements.

Witness Oliver disagreed with witness Alvarez's assertion that DEC's cost-benefit analyses overstate benefits to C&I customers, calling this assertion misleading. As to witness Alvarez's critique of DEC's IMPLAN analysis, witness Oliver stated that the impact of rate increases was outside the scope of that analysis.

Witness Oliver asserted that the cost-benefit analyses included in his direct testimony provide metrics for the programs, such as the amount of O&M savings DEC anticipates, the amount of avoided capital costs DEC anticipates, and the number of outages each program is anticipated to avoid. He said that DEC will track project/program scope, schedule, cost and benefits as appropriate during implementation.

In response to witnesses who argued that DEC's transformer retrofit, bank replacements, breaker replacements, and transmission line rebuilds were not appropriate grid modernization initiatives and that they are business-as-usual activities, witness Oliver stated that the GIP accelerates the pace of these efforts to better position DEC to deal with the future requirements.

As to DEC's Targeted Undergrounding program, witness Oliver acknowledged that its scope had been scaled back by about 90%. He said the remaining program is highly cost beneficial. He disagreed with witnesses who asserted that Targeted Undergrounding is not standard industry practice and that both Dominion Energy in Virginia and Florida Power & Light in Florida have similar programs.

As to DEC's plans to upgrade the security of substations, witness Oliver stated that DEC used a graded approach to physical security at substations not covered by NERC CIP-014, NERC's physical security standard. Witness Oliver stated that most substations will not need security improvements.

In response to critics of Duke's grid modernization stakeholder process, witness Oliver stated that DEC used the feedback received in the workshops to validate the megatrends, conduct additional analyses, drive future workshop discussions, and make significant changes to the portfolio of investments.

He stated that the GIP is a three-year plan, while Power Forward was a ten-year plan, and that the scope of the two plans is dramatically different. He noted that Distribution Hardening and Resiliency and Targeted Undergrounding made up 64% of

Power Forward but are only 11% percent of the three-year GIP, and also that GIP contains several new programs, specifically IVVC at 10% percent of the total, and Physical and Cyber Security at 6%. He stated that SOG is generally supported by all stakeholders; it made up less than 10% of Power Forward but is the largest program in the three-year GIP, making up over 31% of the total. Witness Oliver stated further that the GIP begins to prepare the North Carolina grid for growth in privately owned DER and electric vehicles, but even if this growth does not occur, the plan still is cost-effective. He stated further that there is currently no "Phase 2" of the plan, and any future plan would be based on collaboration with stakeholders.

Witness Oliver acknowledged that the GIP does not address third-party owned DER accommodation in North Carolina. He stated that while some GIP programs and projects provide ancillary benefits to interconnection issues, those benefits are secondary to their primary purposes.

Witness Oliver recommended that the Commission ignore witness Alvarez's recommendation to reject the GIP and establish a proceeding to develop a transparent, stakeholder-engaged distribution planning and capital budgeting process. Witness Oliver referred to Exhibit 3 of his direct testimony, which lists six negative implications of a business-as-usual response to DEC's identified megatrends:

(1) Increased costs;
(2) Reduced reliability and resiliency;
(3) Reduced ability to manage and integrate distributed energy resources;
(4) Reduced ability to meet customer expectations and commitments;
(5) Reduced economic competitiveness for North Carolina; and
(6) Increased geographic and demographic disparity.

Witness Oliver stated that if the Commission were to reject the Company's deferral request, the work in the GIP would have to be sub-optimized, delayed, diminished in scope and effectiveness, and potentially not done at all.

Similarly, witness Oliver rejected arguments that the GIP should be delayed until an IRP or ISOP process is conducted. He asserted that delay could hinder the ability of ISOP to deliver benefits, and he stated that Duke is already engaging stakeholders to develop the ISOP process.

DEC witness McManeus responded to witnesses who expressed concern about the ratemaking aspects of DEC's GIP deferral request. She asserted that cost recovery is a separate and distinct process from deferral of costs. She stated that deferral would allow DEC the opportunity to avoid adverse financial impacts of regulatory lag, but only to the extent the Commission ultimately allows recovery of the deferred cost in a future proceeding. Witness McManeus stated that even if DEC were allowed to defer its GIP costs, the Company would still bear the risk of recovering the costs in a future rate proceeding.

Witness McManeus clarified that DEC is not requesting deferral of its GIP capital expenditures. Rather, DEC is requesting to defer the traditional revenue requirement amounts associated with the GIP capital expenditures. She stated that when the Company makes capital investments as part of the GIP, the cost to be deferred would be the depreciation and return on investment for the completed plant in service. She stated that if the Company spends $1.2 billion in capital over a three-year period, the deferred cost associated with that amount is not $1.2 billion, but instead is three years of annual depreciation and return on that investment, beginning at the date the assets are completed and in service. She explained further that the deferral would include the financing costs related to the amounts that are unrecovered during the period between the in-service date of the asset and when Company rates are updated to include cost recovery of the assets.

Witness McManeus disagreed with one of Public Staff witness Maness's recommended conditions for deferral. She stated that in his supplemental testimony filed February 25, 2020, witness Maness proposed to exclude deferral of a return on the balance of deferred incremental capital costs and incremental expenses. She stated that this return represents the financing costs the Company would incur between the time the GIP costs are incurred and the time that such costs are approved for recovery in future rates.

Witness McManeus disagreed with those witnesses who asserted that deferral would cause customers to bear the risk of cost overruns or GIP scope shortcomings. She stated that the Commission has full authority to address cost overruns or scope issues during a future general rate case when the deferred costs are presented for recovery, and DEC bears the full risk of any disallowances the Commission could choose to impose. During the consolidated evidentiary hearing, witness McManeus stated that by hosting its stakeholder process as directed by the Commission, DEC was able to assure that the GIP programs constitute grid modernization and hence are extraordinary, as opposed to customary spend. Consolidated Tr. vol. 6, 87. She testified further that having "been granted a regulatory deferral as a regulatory asset, . . . I think that's sort of a nod from the Commission to say we understand the costs you're talking about and we don't view them as inappropriate programs or inappropriate electric expenses that one should not ever recover from a customer, assuming that they are reasonable and prudently incurred." Consolidated Tr. vol. 9, 24.

During the consolidated evidentiary hearing, witness McManeus stated that DEC had spent $350 million on GIP from January 2018 through May of 2020. Consolidated Tr. vol. 9, 35. No party disputed these costs.

During the consolidated evidentiary hearing, DEC witness Oliver stated that the Company's capital spending estimates for the GIP programs relied on unit cost estimates that involve a range of cost uncertainty from -20% to +30%. Consolidated Tr. vol. 10, 23.

Stipulations

Public Staff Second Partial Stipulation

In their Second Partial Stipulation, DEC and the Public Staff addressed several issues, including the GIP. The Public Staff agreed to support deferral for the following GIP programs: (1) SOG, (2) IVVC, (3) ISOP, (4) Transmission System Intelligence, (5) Distribution Automation, (6) Power Electronics, (7) DER Dispatch Tool, and (8) Cyber Security. For all other GIP programs, DEC agreed to withdraw its request for deferral accounting.

The stipulating parties agreed that the Second Partial Stipulation constitutes only approval of the decision to incur GIP costs; the Public Staff reserved the right to review actual costs for reasonableness and prudence in the future. DEC and the Public Staff agreed to jointly develop biannual reporting requirements to track GIP expenditures that receive deferral treatment. This will include: (1) tracking costs for each program, including the number of devices installed, types of projects completed, or circuits modified or impacted; (2) reporting on a circuit and substation level; (3) summarizing actual benefits compared to projected benefits; (4) reporting the operational system impacts of SOG and IVVC; and (5) providing data and analyses that inform any significant changes to the scope of the SOG and IVVC programs. The first report would cover spending in the last six months of 2020.

DEC agreed to assess the cost-effectiveness of GIP projects in an on-going manner and to undertake a cost-benefit analysis for its automated lateral device program.

Further, GIP deferral would be restricted to capital costs (return, property tax, and depreciation) related to plant in service and incremental expenses net of operating benefits, for plant placed in service between June 1, 2020, and December 31, 2022, and a return on the deferred balance during the deferral period. Deferral would cease upon the effective date of any general rate case in which the associated eligible plant is included in rate base. If no general rate case order recognizing the entirety of eligible plant in rate base is issued by December 31, 2024, Duke would cease deferral of all eligible net costs and carrying costs and consult with the Public Staff regarding the beginning of amortization of the deferred costs for regulatory accounting and ratemaking purposes. Under the Second Partial Stipulation, GIP deferral would not include overhead or administrative and general costs, but the capitalized project costs may include a reasonable allocation of management and supervision costs.

During the consolidated portion of the evidentiary hearing, DEC witness Oliver stated that to his knowledge the Second Partial Stipulation with the Public Staff does not have a spending cap, nor does it include performance guarantees. Consolidated Tr. vol. 6, 33-34, 68. Witness McManeus confirmed that the Second Partial Stipulation does not include a spending cap. *Id.* at 94. She stated that the ROE impact for the eight GIP programs in the Second Partial Stipulation was a cumulative impact of 70 basis points in year three if the Commission were to deny the deferral, but DEC nonetheless pursued full GIP spending. *Id.* at 108. Witness Oliver said that the benefits of the programs, as stated in his direct testimony Exhibit 7 cost-benefit analyses, would be tracked under the Second Partial Stipulation. *Id.* at 16. Witness Oliver also stated that DEC will implement GIP regardless of whether the Commission approves the Company's deferral request but emphasized that the deferral would give DEC the ability to implement the GIP programs more quickly and cost-effectively. *Id.* at 56.

Commercial Group Stipulation

In the CG Stipulation Commercial Group agreed not to oppose or support DEC's GIP deferral requests. However, DEC agreed that any GIP costs that are allocated to its optional power service, time of use with voltage differential customers, shall be recovered through demand charges.

CIGFUR Stipulation

In the CIGFUR Stipulation CIGFUR agreed to support DEC's GIP deferral request but reserved the right to review and object to the reasonableness of specific project costs in future rate cases. DEC agreed to allocate GIP costs using the minimum system method and voltage differentiated allocation factors for distribution plant.

Harris Teeter Stipulation

In the HT Stipulation Harris Teeter agreed to support approval of GIP deferral but is not precluded from taking any position in future cost recovery proceedings. DEC agreed to allocate GIP costs to OPT-V customers via demand charges.

Vote Solar Stipulation

In the Vote Solar Stipulation, Vote Solar agreed to support DEC's deferral of costs for the following GIP programs: ISOP, IVVC, SOG, Distribution Automation, Transmission System Intelligence, DER Dispatch Tool, and the 44-kV Line Rebuild. The Vote Solar Stipulation states that Vote Solar believes that these investments will enable and support the greater use of DER. Vote Solar agreed not to oppose deferral of the other GIP programs' costs. Further, "to the extent that DEC enters into an agreement with other intervening parties agreeing to a cost cap," Vote Solar supports such cost containment measures. DEC committed to develop potential pilot GIP customer programs to increase the use of distributed resources prior to submission of its 2022 IRP. If DEC and Vote Solar agree that these programs are cost-effective and meet Commission requirements, DEC agreed to file them for approval, and Vote Solar agreed to support such approval. Vote Solar reserved its right to review and object to specific project costs in future rate cases.

NCSEA/NCJC et al. Stipulation

In the NCSEA/NCJC et al. Stipulation NCSEA and NCJC et al. agreed to support DEC's deferral request for: (1) ISOP, (2) IVVC, (3) SOG, (4) Distribution Automation, (5) Transmission System Intelligence, (6) DER Dispatch Tool, and (7) 44-kV Line Rebuild, stating that these programs will enable and support greater use of DER. For all other GIP investments, NCSEA and NCJC et al. do not oppose deferral.

For its part, DEC agreed that congestion relief will be a primary criterion in planning and decision-making regarding future transmission and distribution investment, and that DEC will implement the basic elements of ISOP in its 2022 IRP. Following the 2024 IRP, DEC agreed that it will provide hosting capacity analyses for a sample of circuits, contingent on the Commission approving recovery of the costs. In addition, DEC agreed to preview a distributed generation guidance map with the TSRG in third quarter 2020, incorporate input, and publish it. Finally, DEC agreed that its 2021 IRP will include details of how DERs and non-wires applications will be examined in ISOP.

During the consolidated portion of the evidentiary hearing, witnesses Alvarez and Stephens agreed that the programs supported by NCSEA and NCJC et al. would support renewable energy deployment or improve reliability. Consolidated Tr. vol. 8, 97.

DEC Joint Testimony

On August 5, 2020, DEC witnesses Oliver and McManeus filed joint testimony and exhibits in response to a July 23, 2020 order by which the Commission directed DEC to file supplemental GIP economic analyses. The DEC analyses showed the revenue requirement and rate impacts of approving deferral for the smaller group of GIP projects covered in the Second Partial Stipulation. Page 1 of GIP Exhibit 3 – Deferral Granted (Settlement) of that testimony showed that under the Second Partial Stipulation, deferral and a subsequent rate case in 2024 would produce a revenue requirement of $126.6 million in 2024 and a rate increase at that time of 3.8% for residential customers, 2.1% for general service customers, and 1.6% for industrial customers. This analysis used the ROE and capital structure agreed to in the Second Partial Stipulation.

Witness Oliver testified that if the Commission does not grant deferral accounting, the Company will likely vary its GIP spending from year to year, performing smaller pieces of GIP over a much longer timeframe, which would delay benefits for customers. He stated that the deferral mechanism would give DEC the ability to implement the GIP programs in a much more cost-effective, planned-out way, and to bring the benefits to customers sooner. Further, the deferral would allow DEC to accelerate the historical pace of GIP spending to better position DEC for the future. Consolidated Tr. vol. 6, 45-46.

Witnesses Oliver and McManeus jointly testified that in order to perform GIP work at the pace and scope that provides the most benefit to customers, DEC needs new and modern ways to recover costs and avoid regulatory lag that can harm the Company's financial metrics and, in turn, customers.

DEC witness McManeus testified that investments in generating plant lend themselves much better to being able to manage regulatory lag than do distribution investments, but even with generation investments, there are deferrals. She further explained that, because of the short construction period for GIP investments, the Company is not allowed to record allowance for funds used during construction (AFUDC) for this spending. She stated that AFUDC represents the Company's financing costs during construction and that being able to record AFUDC allows DEC to capitalize those financing costs as part of plant for eventual rate recovery. This "allows the Company to be made whole" and avoids regulatory lag. Consolidated Tr. vol. 9, 31-32.

Witness Oliver further testified that DEC's GIP programs "are the core of grid modernization" because they provide two-way power flows, advanced distribution planning, the ability to control VAR flow from a central hub, the ability to control voltage at substations and on lines, and the ability to leverage AMI meter information. He said these are foundational to building a modernized grid. Making these investments now will make ISOP more effective than it would be otherwise. Tr. vol. 10, 30.

DEC Late-Filed Exhibit 5

On September 8, 2020, at the request of Commissioner Hughes during the consolidated evidentiary hearing, DEC filed Late-Filed Exhibit 5, which shows the revenue requirement savings that DEC expects from the GIP programs agreed to in the Second Partial Stipulation. That unverified exhibit shows a revenue requirement reduction of $8.3 million in 2023 and $9.2 million in 2024, growing to $56.9 million in 2032. The majority of the benefits in 2032 ($29.6 million) are due to fuel savings from the IVVC initiative.

Public Staff Supplemental Testimony

In his September 8, 2020 supplemental testimony, witness Thomas testified that during the update period of February through May 2020, DEC closed to plant $34.7 million of GIP investments. He stated that about $7.1 million of that was for SOG segmentation and automation projects on 58 circuits. Of those 58 circuits, only two were fully enabled, 13 were slated for enablement in 2020, and the remaining 43 are not expected to be fully enabled until 2021 or 2022. Thomas stated that DEC had told the Public Staff that the personnel who program the software to enable each segment had not been able to keep up with the increasing pace of expenditures. Thomas concluded that these investments nonetheless are "used and useful" and eligible for inclusion in rate base even though they were not fully enabled.

In his third supplemental and settlement testimony filed on September 9, 2020, witness Maness stated that he had performed a general overview of DEC's additional GIP testimony and exhibits that were filed on August 5, 2020. He expressed concern that DEC's filing did not appear to reflect the impact of any accumulated deferred income taxes. He also reiterated his recommendation that, if the Commission approves a GIP deferral, it should not decide on an amortization period at this time. He stated that there is no "natural" amortization period in this instance, and we do not know the circumstances that DEC will face when the deferred GIP costs are presented for amortization. Therefore, he testified, that it makes better sense to decide on a reasonable amortization period when the facts are clearer.

DEC Supplemental Rebuttal Testimony

DEC witness Oliver responded to witness Thomas's supplemental testimony by stating that the timeframe is longer than Duke would like between construction and enablement of SOG segmentation and automation projects. He stated that once DEC is fully staffed it will take about 12 weeks between construction work completion and enablement. Witness Oliver said that these 12 weeks are needed to schedule multiple interdependencies between the reliability engineers who create the device settings, the model builders who program the devices into the software and facilitate testing and validation, and coordination with grid management technicians to ensure devices present correctly in the distribution control center. Witness Oliver testified that as COVID restrictions ease, DEC intends to begin building the staff required to reach the targeted 12-week timeframe. He stated that meeting the 12-week timeframe can be an additional metric tracked pursuant to the Second Partial Stipulation.

Discussion and Conclusions

In its 2018 rate case DEC sought approval for a rider, or alternatively, for deferral accounting treatment, for a similar set of grid modernization programs referred to by the Company as Power Forward. The Power Forward proposal involved $13 billion in capital spending over ten years for both DEC and DEP. The Power Forward proposals were strongly contested by most parties to the 2018 rate case proceeding, including the Public Staff, and ultimately not approved by the Commission. In rejecting Power Forward, however, the Commission directed DEC to use an existing proceeding, such as the IRP docket, to inform the Commission as to its grid modernization needs and suggested that the Company collaborate with stakeholders in developing any future grid improvement programs. Tr. vol. 11 at 628-29. In response to the Commission's recommendation, the Company convened three in-person stakeholder workshops and a series of webinars addressing the Company's plans for grid improvement. *Id.* at 629. Witness Oliver stated that the Rocky Mountain Institute acted as a neutral facilitator in each of the three workshops and prepared detailed, post-project reports that were filed with the Commission at the conclusion of each workshop. *Id.* at 629-30. Witness Oliver testified that because of these stakeholder engagements the Company made significant changes to its portfolio of investments, provided cost benefit analysis and underlying data sources and work sheets for all applicable programs and projects to stakeholders, and responded to questions concerning distributed renewable energy resources. *Id.* at 630-31. The Commission recognizes the effort expended by the Companies to engage with stakeholders, as the Commission had directed them to do.

In the instant proceeding, subsequent to its initial request for approval to defer costs related to $1.3 billion in spending on 16 programs aimed at addressing its grid modernization needs, DEC worked with the Public Staff to reduce further its planned investment, and the Public Staff agreed to DEC's requested deferral accounting treatment for that investment. Specifically, pursuant to the Second Partial Stipulation, DEC seeks deferral of the capital costs associated with GIP investments made from June 2020 through December 2022 for the following programs, the descriptions for which are derived from witness Oliver's direct testimony (including his Exhibit 10) and augmented with testimony from the consolidated portion of the evidentiary hearing:

(1) Self-Optimizing Grid (SOG). This initiative has three components: capacity, connectivity, and automation. Capacity projects expand substation and distribution line capacity to allow customers to be served from two directions. Connectivity projects create tie points between circuits. Automation projects provide intelligence and control, enabling the grid to dynamically reconfigure around trouble and better manage distributed energy resources. The advanced distribution management system is software that leverages the intelligence from the grid with information from substation equipment, intelligent switches and distributed energy resources to optimize power flow and minimize the impact to customers when faults occur. It is the centralized system for managing the grid.

(2) Integrated Volt/VAR Control (IVVC). Allows the distribution system to optimize voltage and reactive power via remotely operated substation and distribution line devices such as voltage regulators and capacitors. The grid operator can lower the voltage to reduce peak demand or to reduce overall energy consumption and system losses. Witness Oliver stated that DEC plans to convert 60% of its circuits to IVVC over three years, focusing on suburban areas where customers are more likely to adopt rooftop solar and electric vehicles. Consolidated Tr. vol. 6, 59.

(3) Distribution Automation. Includes four programs. The hydraulic-to-electronic recloser program involves the replacement of oil-filled devices with modern, remotely operating reclosing devices that support continuous system health monitoring. The fuse replacement program replaces one-time-use fuses with automatic devices that reset themselves. The underground system automation program modernizes the protection and control in underground systems that serve critical, high-density areas such as urban business districts and airports. The system intelligence and monitoring pilot develops advanced diagnostic tools that help engineers and technicians address electrical disturbances on the distribution system.

(4) Transmission System Intelligence. DEC will replace electromechanical relays with remotely operated digital relays, implement intelligence and monitoring technology capable of providing asset health data to drive predictive maintenance programs, deploy remote monitoring and control of substation and transmission line devices, and install resiliency projects that leverage state of the art equipment such as digital relays, gas breakers and other equipment enabled with SCADA communication and remote monitoring and control capabilities to rapidly respond to system outages or disturbances.

(5) Integrated System Operations Planning (ISOP). Involves the integration and refinement of existing system planning tools and the development of new analytical tools. It is a multi-year program to build and integrate the tools and processes needed to accommodate an integrated approach to plan and

operate the electric utility system. One example is the Morecast circuit level load forecasting tool, which is necessary to enable the Advanced Distribution Planning tool.

(6) Distributed Energy Resource (DER) Dispatch Tool. Will provide system-wide visualization and control of large-scale DERs, enabling DEC to model, forecast and dispatch them. It will provide operators with a more automated and refined toolset to optimize management of both utility and customer owned DERs to meet system stability requirements.

(7) Power Electronics for Volt/VAR Control. This limited deployment of advanced solid-state technologies like static VAR compensators will help DEC manage power quality issues associated with increasing DER penetration.

(8) Cyber Security. These programs include cyber security enhancement, protection from electromagnetic pulses and electromagnetic interference, a device entry alert system, and a distribution line cyber protection and secure access device management. During the consolidated portion of the evidentiary hearing, witness Oliver stated that the cyber-related portions of GIP are essentially the same efforts that DEC has been funding in the past, only the amount of spending is larger. Consolidated Tr. vol. 5, 39.

The Second Partial Stipulation constitutes agreement between the Public Staff and DEC as to the decision to incur GIP costs and the deferral accounting treatment of those costs. The Public Staff expressly reserved the right in the agreement to review actual costs incurred by DEC for reasonableness and prudence in future proceedings. Additionally, DEC and the Public Staff agreed to develop jointly biannual reporting requirements to track GIP expenditures that receive deferral treatment, including: (1) tracking costs for each program, including the number of devices installed, types of projects completed, or circuits modified or impacted; (2) reporting on a circuit and substation level; (3) summarizing actual benefits compared to projected benefits; (4) reporting the operational system impacts of SOG and IVVC; and (5) providing data and analyses that inform any significant changes to the scope of the SOG and IVVC programs. The first report would cover spending in the last six months of 2020. Additionally, DEC agreed to assess the cost effectiveness of GIP projects in an on-going manner and to undertake a cost-benefit analysis for its automated lateral device program.

Further, the Public Staff and DEC agreed that the costs deferred would be limited to only capital costs (return, property tax, and depreciation) related to plant in service and incremental expenses net of operating benefits, for plant placed in service between June 1, 2020, and December 31, 2022, as well as a return on the deferred balance of such costs during the deferral period. The deferral would cease upon the effective date of any general rate case in which the associated eligible plant is included in rate base. The Public Staff and DEC agreed that if no general rate case order recognizing the entirety of eligible plant in rate base is issued by December 31, 2024, DEC would cease deferral of all eligible net costs and carrying costs and consult with the Public Staff regarding the beginning of amortization of the deferred costs for regulatory accounting and ratemaking purposes.

In addition to the agreement with the Public Staff, DEC reached stipulations related to the GIP programs with 14 parties, including: (1) Vote Solar; (2) Harris Teeter; (3) BJ's Wholesale Club; (4) Ingles Markets; (5) Walmart; (6) Food Lion, (7) JC Penney; (8) Macy's; (9) CIGFUR; (10) NCSEA; (11) NCJC; (12) NCHC; (13) SACE; and (14) NRDC. Several of those stipulations address cost allocation issues related to costs incurred for the GIP programs, which are not ripe for decision by the Commission at this time. Because the issues of cost allocation for costs associated with the GIP programs are not before the Commission for a determination in this proceeding, the Commission considers them to be properly reserved for the cost recovery proceeding, which would be DEC's next general rate case.

Under North Carolina law, a stipulation entered into by less than all parties in a contested case "should be accorded full consideration and weighed by the Commission with all other evidence presented by any of the parties in the proceeding." *CUCA I*, 348 N.C. at 466. Further, "[t]he Commission may even adopt the recommendations or provisions of the nonunanimous stipulation as long as the Commission sets forth its reasoning and makes 'its own independent conclusion' supported by substantial evidence on the record that the proposal is just and reasonable to all parties in light of all the evidence presented." *Id.*

Because of the structure and scope of the stipulations reached with the various settling parties, the Commission concludes that the GIP programs for consideration are those contained in the Second Partial Stipulation, which includes a commitment by DEC to withdraw its request for deferral accounting treatment for individual GIP programs that are not specifically supported by the Second Partial Stipulation. The settlements with the other intervenors either provide express support for or non-objection to the deferral of costs associated with the programs specifically agreed to in the Second Partial Stipulation.

The Commission understands the Second Partial Stipulation, considered together with the settlements reached between DEC and other intervenors, to have resolved GIP-related issues between DEC and the majority of intervenors that filed testimony relating to GIP issues. The only parties whose active opposition to GIP in the form of filed testimony were not resolved through these settlements are CBD/AV, NC WARN, the Tech Customers, and CUCA.

The Commission concludes that the Second Partial Stipulation, as well as the additional settlement agreements, constitute material evidence in this proceeding with regard to the GIP-related issues and should be afforded significant weight by the Commission.

At the direction of the Commission the Company engaged with stakeholders to redefine its grid modernization plans following its 2018 rate case proceeding. The scope of the Company's GIP proposal was further narrowed though additional negotiation with the Public Staff, and programs that had been criticized as being routine operation expense as opposed to grid modernization were dropped from the proposal that ultimately was adopted in the Second Partial Stipulation. At the expert witness hearing Public Staff witness Thomas testified that the Public Staff had investigated each program included in the Second Partial Stipulation, focusing on costs and benefits, and has an understanding of what ratepayers are getting, in terms of fuel savings and reduced operational costs. The Commission is persuaded by the testimony of witness Thomas that the Public Staff has an understanding of the operational benefits that have been estimated by DEC and the type of reliability improvements that customers might see, Consolidated Tr. vol. 7, 69, and concludes that the Public Staff entered into the Second Partial Stipulation with this understanding. Also, the Commission gives weight to the testimony of DEC witness Oliver as to his confidence in the cost estimates underlying the GIP proposals as well as cost control measures that the Company will implement. Consolidated Tr. vol.10, 23-25, 42-43.

The Company and Public Staff witnesses provided significant reassurance to the Commission that the eight GIP programs included in the Second Partial Stipulation are defined on the record as to scope, implementation, and initial budgets; that the Company has significant experience in implementing similar programs in many cases; and that rigorous project management and evaluation mechanisms will be utilized by the Company in implementing and monitoring these programs. These mechanisms will include reporting to the Commission at six-month intervals on the progress of such implementation as anticipated in the Second Partial Stipulation.

The test historically utilized by the Commission in assessing the propriety of a request for deferral accounting treatment is whether the costs proposed for deferral are extraordinary in type and extraordinary in magnitude. Tr. vol. 20, 527-29. However, this test is not the exclusive basis upon which the Commission has previously allowed deferral of costs incurred by utilities, and, as was noted in the 2018 DEC Rate Order, the Commission may approve a deferral within a general rate case with parameters different from those applied in contexts other than general rate cases. 2018 DEC Rate Order at 149. Unlike the consideration of a deferral request outside of a general rate case when a single expense is being brought to the Commission's attention, in a general rate case the Commission has the benefit of a complete picture of the Company's financial health, of all of its expenses and revenues, and the impact of a deferral of future costs on the revenue requirement being approved in that general rate case. Therefore, the typical concerns are not an issue in the present case because the request is not being determined outside of a general rate case, but rather is being determined in a general rate case, a proceeding in which all items of revenue and costs are reviewed.

Additionally, the Commission's 2018 DEC Rate Order declared that "with respect to demonstrated [grid modernization] costs incurred by DEC prior to the test year in its next case, the Commission authorizes expedited consideration, and to the extent permissible, reliance on leniency in imposing the 'extraordinary expenditure' test." *Id*. Public Staff witness Maness explained that the Public Staff took special notice of language in the Commission's 2018 DEC Rate Order that suggests leniency regarding the magnitude of costs or financial impacts necessary to justify deferral. Consolidated Tr. vol. 7, 32, 48; tr. vol. 20, 538. Further, in explaining why the Public Staff opposed the

Company's Power Forward proposal but supported the GIP proposal set forth in the Second Partial Stipulation, witness Maness indicated that the Power Forward rider proposal was not clear on whether and the extent to which costs would be reviewed, but the Second Partial Settlement does establish and provide for rigorous review at the time the Company seeks cost recovery. Tr. vol. 7, 44. Public Staff witness Maness also expressed concern at the Company's position that, absent deferral approval, the Company would reduce spending on the GIP programs by 80%. *Id*. at 45. Finally, Public Staff witness Maness testified that the Public Staff "agreed to the settlement in terms of settling all of the issues in the case, and there was give-and-take amongst all of them" and further that "in the interest of settling the case, [the Public Staff] think[s] that it's acceptable for deferral to be approved for the expanded scope of programs that are reflected within the settlement." *Id*. at 49. Witness Maness made clear that the Public Staff was not generally abandoning its initial position in the proceeding, which involved application of the traditional deferral test, but that in the interest of settlement of issues agreed to the GIP proposals as reflected in the Second Partial Stipulation.

Given the evidence of record, the Commission accepts the terms of the Second Partial Settlement as to the GIP proposals, including the request for deferral accounting treatment. However, in approving the request for deferral accounting treatment for the GIP proposals set forth in the Second Partial Stipulation, the Commission deems it necessary and appropriate to limit the GIP costs that will be allowed deferral accounting treatment to $800 million, consistent with DEC's planned spending, in order to provide an incentive for DEC to manage its GIP spending cost-effectively and mitigate the risk of over-spending. In light of the fact that the Commission retains the ultimate authority to deny recovery of imprudently incurred or unreasonable costs — even if such costs have been previously deferred — the Commission finds that adequate protections against risks inherent in the design, budgeting, implementation, and monitoring for the eight settled GIP programs are adequately addressed in the record, in the Second Partial Stipulation, and by the implementation of the $800 million limitation on the deferral.

NC WARN witness Powers testified that the Commission should reject the Company's GIP as unreasonable on the basis that the GIP projects are indistinguishable from traditional spend projects, with no formal applications or associated evidentiary process to evaluate the reasonableness or potential alternatives for these proposed expenditures. Witness Powers also contended that the stakeholder workshops used to develop the GIP were essentially sales presentations by the Company that did not adequately review the scope and cost of the GIP. Similarly, CBD/AV witness Ryan argued, generally, that the Company has failed to provide sufficient explanation as to how the GIP programs are different from traditional spend and have failed to demonstrate that the GIP programs providing requisite information concerning how these costs affect ratepayers and the public interest. In spite of the contentions of NC WARN and CBD/AV, the Commission concludes that the work undertaken by the Company in the stakeholder process to refine its grid modernization proposals and, thereafter, the additional work with the Public Staff to further limit the proposals and associated spending distinguish the proposals from previous proposals. This conclusion is further supported by the unrebutted testimony of Company witness Oliver, who described the GIP program proposals as "foundational" to managing the transition from grid consisting primarily of one-way power flows to a two-way power flow dynamic. Consolidated Tr. vol. 5, 40.

CUCA witness O'Donnell generally took issue with the GIP proposals, expressing concern over costs associated with the programs and the similarity to the Power Forward proposals that had been rejected by the Commission. However, witness O'Donnell did provide several recommendations as to how the Commissions should address the GIP proposals, including making cost recovery contingent upon the Company meeting the reliability targets as set forth by DEC in its cost benefit analyses and allowing cost recovery if and only if the reliability targets are reached every year. The Commission notes the concerns expressed by CUCA witness O'Donnell but gives weight to the fact that, per the terms of the Second Partial Stipulation, Duke and the Public Staff will jointly develop metrics to monitor the implementation and measure the effectiveness of the programs. Further, DEC agreed to report such metrics, including cost-effectiveness, for each of the agreed programs on a regular basis beginning with expenditures made during the last six months of 2020. On this point, at the expert witness hearing DEC witness Oliver testified that the Company will be able to measure the performance of and the benefits achieved by the programs. Additionally, Public Staff witness Thomas indicated comfort with the parties' ability to measure GIP program performance and confirmed the Public Staff's intention to monitor GIP program performance closely. Thus, the Company has committed to report to the Commission on the effectiveness and cost-effectiveness of the programs. The Commission will hold the Company to this commitment, and the Commission anticipates that these data will be taken into consideration by the Commission in the cost recovery proceedings.

Tech Customers witness Strunk testified that approval of cost deferral could result in regulatory imbalance, noting that the deferral accounting transfers risks from the Company to its customers and will raise customer rates to the benefit of the Company. Witness Strunk also testified that the Company's GIP proposals are substantially similar to Power Forward, for which the Commission elected not to approve deferral accounting. Finally, witness Strunk argued that even if deferral were appropriate for GIP costs, it is premature for the Commission to authorize the deferral given that the Company is also in the planning stages of implementing ISOP and that the ISOP process could affect the nature and level of investment required under the Company's GIP. The Commission acknowledges the link between the GIP proposals set forth in the Second Partial Stipulation and Power Forward. But as previously discussed, the Commission concludes that the work undertaken by the Company in the stakeholder process to refine its grid modernization proposals and, thereafter, the additional work with the Public Staff to further limit the proposals and associated spending distinguish the proposals in the Second Partial Stipulation from previous proposals. In addition, the Commission notes witness Strunk's warning regarding transfer of risks but concludes that when the costs are before the Commission for recovery, the burden will be on the Company to prove that those costs were reasonably and prudently incurred, which will mitigate this risk. Further, the Commission intends that the $800 million limit on the deferral will serve as a guardrail against over-spending by the Company.

The Commission takes note of Tech Customers witness Strunk's testimony highlighting the tension between implementing a grid modernization effort now, versus waiting for implementation of the ISOP process that is under development. The Commission is persuaded by witness Oliver's testimony that the majority of the GIP programs are foundational and should be pursued at this time. However, the Commission agrees with the Tech Customers that additional grid modernization investments beyond 2022 should be informed by the ISOP process. Thus, going forward the Commission expects any request related to grid modernization investments to be informed and justified by the ISOP process.

The Commission has carefully reviewed the evidence on DEC's GIP proposal in this docket and concludes that acceptance of the Second Partial Stipulation's provisions between the Public Staff with DEC related to the GIP programs is appropriate and is supported by material and substantial evidence of record.

The Commission's acceptance of the GIP provisions of the Second Partial Stipulation is limited. The Commission's decision simply allows DEC to treat costs incurred in pursuing the settled GIP programs as regulatory assets pending a prudence and reasonableness determination in a later rate case. DEC remains fully at risk for the reasonableness and prudence determination of its GIP costs and for its ultimate recovery from customers, as would be the case if DEC simply undertook these programs without a deferral and then sought recovery of the costs in a rate case. The only difference is that deferral of these costs allows certain between-rate-case earnings impacts of these costs to be held on the books of DEC as a regulatory asset and preserves them for possible future recovery if they are determined by the Commission, in a future proceeding, to be just and reasonable, prudently incurred, and otherwise eligible for recovery from customers.

The Commission concludes that the parties have compromised significantly to reach agreement, as evidenced by the Second Partial Stipulation, and deferral treatment for the GIP programs identified in the Second Partial Stipulation is reasonable and in the public interest. The Commission recognizes that the Company has undertaken stakeholder engagement efforts since the last rate case and made considerable efforts in this regard, as directed by the Commission. Through the stakeholder process, and continuing through this rate case proceeding, the Company has significantly narrowed its planned spending. The accounting deferral request, as modified by the Second Partial Stipulation with the Public Staff, and supported by other intervenor settlement agreements, represents a set of programs that can be classified as grid modernization, along with reporting requirements that will ensure collaboration and transparency as investments are made. The approval for deferral accounting treatment is limited to $800 million, which will incent Duke to manage its spending, and any amounts actually spent and deferred by the Company will be subject to review for reasonableness and prudence before any such costs are passed on to customers. Finally, the deferral accounting treatment approved in this proceeding shall be considered specific only to this case in light of the evidence of record in this proceeding and shall not be given any precedential value by the Commission with regard to any future general rate case proceeding or deferral request or any other proceeding before the Commission at any point in the future.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 42–48

Tax Act Issues

The evidence supporting these findings of fact is found in the verified Application and Form E-1; the Public Staff First and Second Partial Stipulations and CIGFUR Stipulation; the testimony and exhibits of DEC witnesses De May, McManeus, Newlin, Hager, Panizza, and Hevert, Public Staff witnesses Boswell and Hinton, CBD/AV witness McIlmoil, CIGFUR witness Phillips, CUCA witness O'Donnell, and Tech Customers witness Strunk; and the entire record in this proceeding.

Summary of the Evidence

DEC Direct Testimony

Witness De May

Witness De May noted that the impacts of the Federal Tax Cuts and Jobs Act of 2017 (Tax Act) have been incorporated into the Company's request, as outlined in the testimony of witnesses Panizza and McManeus.

Witness McManeus

Witness McManeus described DEC's proposal to refund to customers through a rider the federal and state corporate income tax amounts related to the Tax Act and recent reductions to North Carolina corporate income tax rates. Witness McManeus provided McManeus Exhibit 4 with her direct testimony to illustrate the proposed rider to refund EDIT to customers.

Witness McManeus noted that DEC, in its Sub 1146 rate case, adjusted its rates to reflect reduced income tax expense related to the reduction in the federal corporate income tax rate from 35.00% to 21.00% as promulgated in the Tax Act, which became law on December 22, 2017. She noted that the lower federal corporate income tax rate continues to be reflected in proposed rates in this proceeding.

Witness McManeus further noted that in Sub 1146 the Commission ordered the Company to maintain the federal protected and unprotected EDIT in a regulatory liability account for three years, or until DEC's next general rate case, whichever was sooner. Witness McManeus stated that in compliance, DEC is proposing a method of returning EDIT to its customers through a rider.

Witness McManeus maintained that DEC's proposed Rider EDIT-2[12] contained five categories of benefits to customers, as follows:

(1) Federal EDIT – protected;
(2) Federal EDIT – unprotected, Property, Plant & Equipment (PP&E)-related;
(3) Federal EDIT – unprotected, non-PP&E related;
(4) Deferred (provisional) revenue – federal income tax; and
(5) NC EDIT.

1. Federal EDIT – protected

Witness McManeus stated that these amounts are generally related to PP&E, and there are specific IRS requirements mandating that these amounts not be returned to customers quicker than prescribed by the IRS. Witness McManeus testified that the amortization period DEC is using for protected EDIT is called the average rate assumption method (ARAM), and results in a Year 1 amortization rate for this category of 2.53%. She noted that protected amounts ultimately become unprotected over time and, as such, DEC estimated this amount and captured this transition from the protected to unprotected category on McManeus Exhibit 4, Page 1, Line 3.

2. Federal EDIT – unprotected, PP&E-related

Witness McManeus stated that these amounts are also related to PP&E but do not fall under the IRS guidelines for protected status. She stated that because DEC would have paid these amounts to the IRS over the remaining life of the underlying property, DEC is proposing to return these amounts to customers over 20 years. She further stated that this approach balances the customers' and the Company's interests, minimizing customer rate volatility and addressing the Company's cash flow concerns.

3. Federal EDIT – unprotected, non-PP&E related

Witness McManeus noted that these amounts are not related to PP&E but are related to items such as regulatory assets and liabilities, and other balance sheet items. She stated that as noted by DEC witness Panizza, these items have an average life of approximately seven and one-half years. Witness McManeus testified that DEC is proposing to return these amounts to customers over a five-year period. She also stated that the Company has included in this category amounts transitioning from the protected category to unprotected status.

4. Deferred (provisional) revenue – federal income tax

Witness McManeus stated that as directed by the Commission in Docket No. M-100, Sub 148, DEC began deferring, effective January 1, 2018, the impact on

[12] Rider EDIT-1 represents the state EDIT that is being returned to customers through a four-year Rider as approved in DEC's Sub 1146 rate case.

customer rates of the reduction in the federal corporate income tax rate from 35.00% to 21.00%. Witness McManeus noted that beginning August 1, 2018, new rates approved by the Commission in Sub 1146 reflected the lower federal corporate income tax rate. She stated that after August 1, deferral amounts are related to continuing accrual of returns on the deferral balance. She testified that McManeus Exhibit 4, Page 1, Line 8, shows the projected balance of this liability as of January 31, 2020. She further stated that DEC proposes to refund this amount to customers over a five-year period. Witness McManeus stated that DEC will continue to defer the impact from February 1, 2020, through the effective date of new rates in this case. She also noted that those additional amounts are not being estimated now but will be included in the Year 2 EDIT rider calculation.

5. NC EDIT

Witness McManeus testified that like the EDIT that results from the reduction in the federal corporate income tax rate, there are EDIT balances that resulted from the reduction in the North Carolina corporate income tax rate. She noted that in Sub 1146 the Commission approved a four-year state EDIT rider to return EDIT resulting from reductions in the state corporate income tax rate in prior years (Rider EDIT-1). Witness McManeus commented that the state EDIT rider currently in place does not include EDIT related to the reduction in the North Carolina corporate income tax rate from 3.00% to 2.50%, effective January 1, 2019. She stated that DEC is proposing to incorporate the refund of the new state EDIT in the EDIT proposed in this case (Rider EDIT-2), over a five-year period.

Witness McManeus stated that the proposed rider will include the annual amortization for each of these five categories of benefits. She states that the North Carolina retail amounts can be seen on McManeus Exhibit 4, Page 1, Columns A through E. Witness McManeus noted that since these collected EDIT amounts reduce rate base, DEC’s rate base will increase as they are refunded to customers. She stated that, as such, the rider also calculates the adjustment to return on rate base related to the increase in rate base resulting from the refund of EDIT to customers, as shown in McManeus Exhibit 4, Page 2, Column L. She stated that Column M shows the revenue requirement equal to the sum of the amortization and return. Witness McManeus testified that Column N shows the revenue requirement grossed up for the Commission’s regulatory fee and uncollectible expense. Witness McManeus stated that the amount in the Year 1 row on McManeus Exhibit 4, Page 2 of a $154.6 million decrease is the rider amount that is being proposed in this case.

Witness McManeus explained that the Year 1 rider amounts are based on the balance of EDIT at December 31, 2018, as described by DEC witness Panizza and are updated to reflect the expected balance at July 31, 2020, when the proposed rider is expected to be implemented. She stated that this projection will be further updated to reflect actual January 31, 2020 balances, as well as the latest ARAM rate, prior to the hearing.

Witness McManeus stated that years two through five are shown for illustrative purposes. She noted that the actual rider amounts for those years may change based on several factors. Witness McManeus testified that first, the annual amortization amounts will be recalculated to account for any additional adjustments to any of the balances on rows one through five of McManeus Exhibit 4.

Witness McManeus testified that a second factor that would impact the calculation of the rider beyond year one is changes in the ARAM rate. She explained that the Company updates this rate annually and the most current rate must be used when establishing customer rates.

Witness McManeus further testified that a third factor that would impact the calculation of the rider beyond year one is the impact of future rate cases. She stated that in future rate cases, the EDIT balance in base rates shown in Column J and the rate of return used to calculate Column L of McManeus Exhibit 4, Page 2 would be updated based on what is approved in future cases. Witness McManeus also stated that the retention factor used to calculate Column N will be updated to reflect any future changes in the license fee or public utility assessment fee rates as needed.

Witness McManeus testified that DEC proposes to file the rider amounts, along with the spread to the classes and derivation of the rate for each subsequent year, with the Commission annually in this rate case docket by April 30, for rider rates effective July 1.

Witness McManeus filed supplemental direct testimony wherein she updated the EDIT calculation to reflect known changes to the EDIT balances and amortization amounts as of January 2020. She noted that the updated numbers reflect the completion of Duke Energy’s 2018 federal income tax return. Witness McManeus also stated that the annual amortization percentage for protected EDIT has been updated to an actual amount that aligns with the most recently filed federal income tax return that is the Company’s best estimate for the following year’s protected EDIT amortization. She stated that this update is necessary to comply with federal tax normalization rules referenced in her direct testimony. Witness McManeus explained that a second amount that has been updated is related to the North Carolina EDIT component of the rider to reflect minor revisions to the EDIT amount.

Witness Newlin

Witness Newlin explained how tax reform could create concerns for customers and for utilities. He noted that deferred taxes are not large pools of money that the Company is holding in an account. Witness Newlin stated that, instead, they are collections that occur over time based on the life of the underlying assets, which are used by the Company during the deferral period to invest in the business to better serve customers. Witness Newlin asserted that customers have benefitted from the use of deferred taxes through the Company’s use of these zero interest loans to finance its business rather than incurring financing costs that are passed on to customers. Witness Newlin argued that when the tax rate changes, either up or down, leveraging the over and under-collection of these funds in a proper and principled manner benefits both the Company and its customers. He maintained that if adjusting rates to account for tax changes is done in a haphazard manner, it can cause rate volatility and harm to customers as well as the financial health of the utility.

Witness Newlin stated that for unprotected EDIT, the question becomes what is the appropriate flowback period to customers that balances both the best interest of customers and the financial strength of the Company and the cash flows of the Company. Witness Newlin maintained that the Company's proposed 20-year flowback of federal PP&E-related unprotected EDIT more closely matches the underlying asset lives and smooths out the Company's cash flow.

Witness Newlin testified on steps taken by several other state utility commissions to mitigate the negative impacts of tax reform.

Witness Hager

Witness Hager explained the allocation factors used in the proposed EDIT rider. She noted that DEC has allocated the benefits in the EDIT-2 Rider in Rate Design exhibits to the classes based on the accumulated deferred income tax allocator. Witness Hager stated that she has reviewed this allocation and believes it is reasonable based on cost causation principles. She maintained that since the EDIT amounts were previously part of accumulated deferred income taxes as explained by DEC witnesses McManeus and Panizza, this is consistent with how the amounts were allocated prior to the federal tax rate change and reasonably reflects how the benefits were created.

Witness Panizza

Witness Panizza noted that the Tax Act reduction in the corporate tax rate is accompanied by many other provisions having varying impacts on the revenue requirement, and that these impacts must be considered particularly as they relate to cash flow.

Witness Panizza stated that DEC's $2,175 million (or $2.2 billion) of EDIT, as of the end of 2018, is in three different buckets. Witness Panizza explained that one bucket contains approximately $1,193 million (or $1.2 billion) as of the end of 2018 of what is called protected EDIT, which is EDIT related to the Company's investment in PP&E whose flowback treatment is expressly made subject to IRS normalization rules by the Tax Act. He noted that the IRS normalization rules require protected EDIT to be flowed back over the remaining lives of the property giving rise to the deferred tax balance. Witness Panizza noted that the remaining EDIT, totaling approximately $982 million, as of the end of 2018, is unprotected under IRS rules, and therefore subject to flowback in a timeframe open to discretionary action by the Commission. Witness Panizza stated that the lion's share of unprotected EDIT, totaling more than $783 million still relates to the Company's investment in PP&E although it is in the second bucket of EDIT. Witness Panizza explained that this portion of unprotected EDIT is not required to be normalized under the Tax Act. Witness Panizza asserted that although both buckets are property-related, the Internal Revenue

Code protects one and not the other. He argued, however, that the rationale for normalization applies to this unprotected portion of EDIT as much as it applies to protected EDIT, and so normalization at some level is appropriate. He stated that assets represented in this bucket have an average life of approximately 23 years for DEC, although the Company's proposal uses a shorter 20-year period over which to accomplish this flowback.

Witness Panizza explained that the third and final bucket, totaling approximately $199 million, as of the end of 2018, is unprotected EDIT. He stated that for DEC, the assets in this bucket include a variety of things, including certain regulatory assets with a two-year life, pension-related EDIT with 12- to 20-year lives, and EDIT that transitioned from protected to unprotected during 2018. Witness Panizza stated that the average life of these assets is six and one-half years.

Witness Panizza testified that while these balances are as of the end of 2018, the Company has made and may make additional adjustments to these amounts in 2019, as protected amounts ultimately become unprotected over time.

Witness Panizza testified in support of the Company's proposed 20-year flowback period and contended that a gradual return of EDIT over the life of the capital asset being depreciated balances the customer and the Company's interests.

He stated that DEC's proposal complies with accounting requirements while preserving DEC's credit rating by not creating undue pressure on cash flows.

CBD/AV Direct Testimony

Witness McIlmoil

Witness McIlmoil stated that DEC is proposing to offset its requested increase by approximately $154.6 million in the first year and by lower amounts in subsequent years to refund to ratepayers tax benefits DEC received as a result of the Tax Act. He noted that the net impact of the refund would be to lower the increase in annual revenues to $290.8 million representing an overall net increase in revenues, again for the first year only, of 6.00%. Witness McIlmoil maintained that as the refund value declines in year 2 and beyond the annual revenue requirement, and thus the percent increase in revenues, would subsequently increase above the year 1 values, resulting in higher rate and cost impacts for DEC ratepayers over time. Witness McIlmoil asserted that these impacts will be further exacerbated by the expiration of the EDIT-1 Rider after August 1, 2022.

CIGFUR Direct Testimony

Witness Phillips

Witness Phillips stated that DEC is proposing to credit customers through Rider EDIT-2 for five categories of taxes that DEC is obligated to refund. He maintained that the Commission should use its discretion to require DEC to refund federal unprotected EDIT as expediently as possible to the ratepayers. Further, witness Phillips urged the

Commission to reject DEC's proposal to refund the federal unprotected PP&E-related EDIT over a prolonged period.

CUCA Direct Testimony

Witness O'Donnell

Witness O'Donnell stated that DEC is seeking a total increase of $445 million that accounts to an overall increase of 9.20%. He noted that this increase does not reflect the return to customers of EDIT. Witness O'Donnell maintained that as a result of the return of the EDIT to those to which it is owed, the net increase is $291 million which equates to a net 6.00% overall increase.

Witness O'Donnell asserted that the Tax Act created EDIT that needs to be returned to the North Carolina retail customers of DEC. Witness O'Donnell noted that the rate increases sought by DEC in this rate case are significantly lower when the return of EDIT is considered.

Public Staff Direct Testimony

Witness Boswell

Witness Boswell noted that DEC did not make an adjustment to exclude any EDIT from rate base but instead proposes to handle each of the five categories in a single rider, with rate changes occurring each year based on the proposed amortizations for these categories, which range from 39.6 years to five years. Witness Boswell asserted that the categories of refunds should be handled separately due to the differing natures of the amounts and the amortization periods. She maintained that such handling provides a more transparent means of tracking the Tax Act and state tax-related refunds to customers for each year. Therefore, witness Boswell recommended several adjustments regarding federal EDIT.

First, witness Boswell recommended an adjustment to remove the federal protected EDIT from the EDIT Rider proposed by DEC and instead leave the amount in base rates. She proposed to amortize the protected EDIT balance over 39.6 years in base rates and to remove the first year of amortization from the deferral amount for purposes of this proceeding.

Next, witness Boswell asserted that DEC has artificially created two categories of federal unprotected EDIT for purposes of its proposal: federal unprotected PP&E which DEC proposes to return to ratepayers over 20 years and federal unprotected other which DEC proposes to return to ratepayers over five years. She contended that the tax normalization rules are very clear, and either EDIT is protected or it is not. Witness Boswell stated that DEC's proposed classification of PP&E-related federal unprotected EDIT is not supportable by any logical accounting or ratemaking principle and should not dictate this Commission's decision as to what is a reasonable amount of time within which to return these funds to ratepayers. She argued that these funds rightfully belong to the ratepayers and should be returned to them as soon as reasonably possible. Witness Boswell recommended that the Commission remove the entire federal unprotected EDIT regulatory liability from rate base and place it in a rider to be refunded to ratepayers over five years on a levelized basis, with carrying costs. She asserted that the immediate removal of unprotected EDIT from rate base increases the Company's rate base (and therefore customer rates) and mitigates regulatory lag that may occur from refunds of unprotected EDIT not contemporaneously reflected in rate base. Witness Boswell asserted that refunding the federal unprotected EDIT over five years allows DEC to properly plan for any future credit needs while refunding ratepayer dollars in a reasonable time.

Witness Boswell further testified that she made an adjustment to remove from DEC's proposed single Rider the overcollection of federal taxes which resulted from the reduction in the federal corporate income tax rate from 35.00% to 21.00% and placed it into a separate levelized rider to be amortized over a one-year period. Witness Boswell stated that she removed the balance from the working capital schedules since she is recommending a refund over one year. She noted that the one-year amortization period is consistent with the period approved by the Commission in the most recent rate cases of Aqua North Carolina, Inc., Carolina Water Service, Inc. of North Carolina, and Piedmont Natural Gas Company, Inc.

Witness Boswell recommended removing the entire state EDIT balance from rate base, as DEC has in its proposed adjustment, and placing it in a separate rider to be returned over one year with a return on the balance. She noted that this is consistent with the Commission's order in a recent Dominion Energy North Carolina docket, Docket No. E-22, Sub 532.

Witness Hinton

Witness Hinton provided testimony on how the Public Staff's proposals on the flowback of federal unprotected EDIT impact DEC's credit metrics. He noted that DEC has provided the Public Staff with the projected credit metrics, specifically the Cash Flow from Operations excluding changes in working capital over total debt (FFO/Debt) under both the Public Staff's proposed five-year flowback proposal and DEC's proposed 20-year flowback proposal for federal unprotected EDIT. He stated that the 20-year flowback of federal unprotected EDIT results in a higher average projected FFO to debt ratio of approximately 42 basis points. Witness Hinton maintained that as noted in Moody's October 31, 2019 Credit Opinion, an FFO to Debt ratio that is between 24% and 26% qualifies for an "A" rating. Witness Hinton noted that given that the FFO/Debt metric is only below 24% in 2021 and the other metrics are 24% or 25% through 2023, he contends that unexpected financial developments would have to occur that reduced DEC's cash flow from operations or cause the Company to issue more debt to trigger a downgrade.

Witness Hinton noted that Moody's places 40% weight on financial strength as measured by its quantitative financial metric, 50% weight on the utility regulation, and 10% weight on utility diversification. He stated that the 50% weight on regulation focuses on two areas: the regulatory framework and the ability to recover costs and earn returns. Witness Hinton maintained that the regulatory framework relates to rate setting by the governing body, credit supportive legislation that is responsive to the needs of the utility, and the way the utility manages the political and regulatory process. He stated that the ability to recover costs and earn returns on its investments relates to the assurance that the regulated rates will be based on prescriptive and clear ratemaking methods. Witness Hinton asserted that while awarding the least weight in its rating methodology to diversification, Moody's positively views utilities with multinational and regional diversity in terms of regulatory regimes and diversity in the economics of its service territories.

Witness Hinton maintained that DEC has other means to finance the EDIT over a five-year period that would not deteriorate DEC's FFO/Debt metrics. He noted that DEC's financial forecast indicates that DEC will continue every year to be financed with 48% to 47% long-term debt and 52% to 53% common equity through 2023. Witness Hinton stated that from 2020 through 2023, the Company's filings indicate that the Company plans to issue a total of $2.40 billion in long-term debt and infuse $4.05 billion to Duke Energy Corporation (the parent). He further stated that this indicated that an option may exist for DEC to offset some of its debt issuances through a reduction in its planned contributions to its parent, which would allow DEC to maintain its credit ratings or, in the event of a downgrade, the ability to restore its current credit ratings. Witness Hinton noted that DEC witnesses De May and Newlin stressed the importance of maintaining DEC's credit quality, which Moody's Investor Services places as the highest-rated among Duke Energy Corporation and its other five electric utility subsidiaries as follows:

Moody's Credit Ratings

	Long-Term Issuer Rating	**First Mortgage Bonds**
Duke Energy Corporation	Baa1	NA
Duke Energy Carolinas	A1	Aa2
Duke Energy Progress	A2	Aa3
Duke Energy Florida	A3	A1
Duke Energy Indiana	A2	Aa3
Duke Energy Kentucky	Baa1	NA
Duke Energy Ohio	Baa1	A2

Witness Hinton also noted that Duke Energy Corporation said it will issue approximately 29 million shares of common stock which will result in approximately $2.5 billion of net proceeds. He stated that this additional equity could allow DEC to decrease its projected equity infusions up to the parent company, which would alleviate the need to issue the amount of new debt and reduce the possibility of a downgrade.

Witness Hinton stated that DEC expects that a one-notch downgrade by Moody's to Aa3 would increase the investor-required bond yield by 5 basis points, and noted that DEC maintains that this estimate was based on market conditions associated with the January 7, 2020 issue of 2.45%, 10-year bonds. Witness Hinton stated that DEC noted that the differential would be greater than 5 basis points if the bond market was under dramatic volatile periods and stated that following DEC's acknowledgement of the current bond market, it is worth noting that Moody's A-rated long-term utility bond yields are the lowest in over 30 years. Witness Hinton asserted that considering the Company's financial forecasts, it is his opinion that the added cost of debt capital from a downgrade to an Aa3 rating will not be burdensome on the Company.

Witness Hinton further stated that if DEC is downgraded, it is not likely that DEC will remain at that level for an extended period. He asserted that while a downgrade to Aa3 is not likely, recent history indicates that if it did occur, it would probably last less than five years. Witness Hinton noted that since 1973, DEC has had six upgrades and four downgrades and that it does not appear that any downgrade resulted from the 1986 change in the federal corporate income tax rate.

Witness Hinton asserted that after his review of the FFO/Debt credit metrics, he supports the refund of federal unprotected EDIT over five years as recommended by witness Boswell. He stated that it is unlikely that spreading the EDIT over five years will result in a debt rating downgrade and that a five-year flowback is reasonable and fair to DEC's ratepayers and the Company.

Tech Customers Direct Testimony

Witness Strunk

Witness Strunk testified that based on a survey of regulatory precedent during the last 12 months, he recommends that the Commission shorten the amortization of federal unprotected EDIT to no more than five years. Witness Strunk maintained that this would provide an offset to DEC's proposed rate increase and will track the prevailing treatment by other regulatory commissions. Witness Strunk noted that he is agreeable to DEC's proposed amortization periods for federal unprotected non-PP&E EDIT (five years), federal provisional revenues (five years), and state EDIT (five years). Witness Strunk provided a survey of news articles during the past 12 months that pertain to federal unprotected EDIT. Witness Strunk stated that the survey evidence supports his position that DEC's 20-year flowback period for federal unprotected EDIT is excessively long.

DEC Rebuttal Testimony

Witnesses De May and Hevert

Witness De May testified that the intervenors propose that the Commission require the Company to flow back hundreds of millions of dollars in EDIT immediately, or in the very short term, which is in stark contrast to the intervenors' position on the recovery of coal ash costs (if over time then without interest at the Company's weighted average cost of capital).

Witness D'Ascendis noted in his rebuttal testimony that the March 2015 Report by Moody's mentioned in witness Woolridge's testimony makes it clear that utilities' cash flows have benefited from increased deferred taxes which themselves were due to bonus depreciation. He stated that the report also notes that the rise in deferred taxes eventually would reverse. Witness D'Ascendis stated that in January 2018, Moody's spoke to the effect of the reversal on utility credit profiles in the context of tax reform as follows:

> Tax reform is credit negative for US regulated utilities because the lower 21% statutory tax rate reduces cash collected from customers, while the loss of bonus depreciation reduces tax deferrals, all else being equal. Moody's calculates that the recent changes in tax laws will dilute a utility's ratio of cash flow before changes in working capital to debt by approximately 150-250 basis points on average, depending to some degree on the size of the company's capital expenditure programs. From a leverage perspective, Moody's estimates that debt to total capitalization ratios will increase, based on the lower value of deferred tax liabilities.

Witness D'Ascendis noted that in June 2018, Moody's changed its outlook on the U.S. regulated sector to "negative" from "stable".

Witness McManeus

Witness McManeus testified that DEC does not oppose rider treatment for EDIT but opposes the specific rider treatment as recommended by the Public Staff. In addition, she stated that DEC does not agree with the recommendations of Tech Customers witness Strunk.

Witness McManeus contended that witness Bowell's exhibits reflect only one side of the $80 million transition of EDIT from the protected to the unprotected EDIT categories between January 1, 2019 and July 31, 2020. She stated that while witness Boswell's levelized federal EDIT – Unprotected Rider does reflect the effect of this transition and the resulting flowback of greater revenue reductions, her calculation of the protected EDIT in base rates excludes the off-setting transition impact and consequent increase in rate base.

Witness McManeus asserted that this is not correct and is not consistent with how this transition is treated in McManeus Exhibit 4 filed with her direct testimony which captures both offsetting effects of the transition on page 1, line 8 of McManeus Exhibit 4 when calculating rate base return impacts in the EDIT rider on page 2 of McManeus Exhibit 4, columns A, K, and L in year 1.

Witness Newlin

Witness Newlin noted that Tech Customers witness Strunk cited 34 separate news articles in the past 12 months as evidence of shorter flowback periods, 13 of which include flowback provisions exceeding the five-year time period proposed, and two which include flowback periods as long as 44 years. Witness Newlin maintained that without the full context of the associated orders, it is impossible to determine the size and scale of the deferred taxes returned and expected cash flow impacts in the context of the respective utility's credit metrics and capital needs. He asserted that DEC faces unprecedented amounts of capital needs in the coming years and already stressed credit metrics.

Regarding Public Staff witness Hinton's testimony, witness Newlin maintained that his analysis focuses on EDIT flowback in isolation and does not consider the cumulative impact of other potentially credit negative proposals by the Public Staff.

Addressing witness Hinton's statement that a downgrade will only last five years, witness Newlin maintained that five years is a long time and witness Hinton's presumption is overly optimistic.

Stipulations

Public Staff First and Second Partial Stipulations

In Section III.16 of the First Partial Stipulation, DEC and the Public Staff agreed to remove the protected federal EDIT from DEC's proposed Rider EDIT and return these amounts to customers through base rates. This change reduces DEC's revenue requirement by $28 million.

In Sections III.A.(2)–(5) of the Second Partial Stipulation, DEC and the Public Staff agreed as follows:

> Total unprotected federal EDIT, North Carolina EDIT, and deferred revenues related to the provisional overcollection of federal income taxes (or the provisional revenues) will be returned to customers through a rider by using a levelized rider calculation methodology as described and set forth in the testimony and exhibits of the Public Staff and will be amortized over a period of five years for total unprotected EDIT and two years for North Carolina EDIT and deferred revenues.

DEC and the Public Staff also reached agreement concerning how to address changes in the federal corporate income tax rate or North Carolina state corporate income tax rate which may occur during the respective amortization periods as provided in detail in Sections III.A.(6)–III.A.(15) of the Second Partial Stipulation. No intervenor offered any evidence or testimony opposing the EDIT provisions of the DEC and the Public Staff partial stipulations.

CIGFUR Stipulation

In Section IV of the CIGFUR Stipulation, CIGFUR and DEC stipulated that federal unprotected EDIT and the provisional revenues should be refunded to customers on a uniform cents per kWh basis.

Discussion and Conclusions on Return of Tax Act Items to Ratepayers

DEC and the Public Staff have stipulated on the appropriate treatment of the tax issues, as follows:

Tax Act Item	Stipulated Treatment
Protected federal EDIT	Remove from rider and amortize in base rates based on the IRS normalization rules
All unprotected federal EDIT	Levelized rider over five years
Provisional Revenues	Levelized rider over two years
State EDIT	Levelized rider over two years

Tech Customers stated in their post-hearing brief that they favor the provisions of the Second Partial Stipulation that unprotected federal EDIT (together with North Carolina EDIT and deferred revenues related to the provisional over-collection of federal income taxes) be returned to customers through a rider using the levelized rider methodology proposed by the Public Staff over a five-year amortization period, as this is the approach that best balances the need to expeditiously return over collections to ratepayers and DEC's interest in managing its cash flow.

Tech Customers also contended that the longer the period customers are forced to wait for return of the over collections, the longer the forced loan from ratepayers. Tech Customers asserted that returning all unprotected federal EDIT over five years is a reasonable approach that appropriately balances the need to return the over-collections to ratepayers and the need to protect both DEC and ratepayers from the shocks that otherwise would result from significant rate decreases followed by rate hikes.

The AGO argued in its post-hearing brief that DEC should promptly return to ratepayers over $1 billion in EDIT and other over-collected taxes, either as a full offset to a rate increase or as a decrease in rates. The AGO noted that reductions in federal and state corporate income tax rates have lowered operating expenses for utilities and urged the Commission to require DEC to return all of the amounts to ratepayers over no more than two years.

Based upon the record of evidence in this proceeding, the Commission gives significant weight to the DEC and Public Staff First and Second Partial Stipulations concerning the tax issues in this case and finds that it is appropriate to approve those portions of the stipulations. The Commission notes that no intervenor presented testimony disagreeing with the provisions of the settlements in this regard, although the AGO contended in its post-hearing brief that federal unprotected EDIT should be returned within two years instead of five years. However, the Commission is not persuaded that it is appropriate to reject the settlements on this point based on the overall benefits of settling these matters. Further, the Commission gives substantial weight to the testimony of Tech Customers witness Strunk and the information he provided concerning the amortization periods for EDIT adopted by other state commissions across the country. Witness Strunk's testimony shows that a five-year amortization period for EDIT is clearly a reasonable period of time when compared to other state commission decisions. The Commission concludes that the amortization periods stipulated appropriately balance the interests of the ratepayers and DEC.

Discussion and Conclusions on Allocation of EDIT and the Provisional Revenues

The CIGFUR Stipulation provides under Section IV that the parties agree to the refund of unprotected EDIT and the provisional revenues on a uniform cents per kWh basis. In his direct and supplemental testimony, DEC witness Pirro described how he designed the Year 1 rate for the EDIT Rider by taking the rider revenue requirement, aggregating it to the four different rate classes based on how it was allocated in the Company's 2018 per books cost-of-service study, and dividing each class by the applicable test year retail billed sales. Tr. vol. 12, 253-60. Witness Pirro noted during cross-examination that these class-specific EDIT refund rates were in line with the cost allocation method used in this docket. Tr. vol. 13, 27. Witness Pirro testified that he used the revenue requirement from McManeus Exhibit 4 to develop the rates in Pirro Exhibit 9. In his second supplemental testimony, witness Pirro explained that he had revised the EDIT Rider pursuant to the CIGFUR Stipulation to refund EDIT on a uniform cents per kWh basis. Tr. vol. 12, 278. Under this method, one factor would be used for all customers, with the OPT-V class receiving a larger EDIT credit than it paid in EDIT, according to witness Pirro. Tr. vol. 13, 28. Witness Pirro contended that this overpayment of EDIT to one class that was paid in by another is a way to correct subsidization within base rates, but he admitted that base rates and EDIT should be considered separately. *Id.* at 28-29. CIGFUR witness Phillips also agreed that paying EDIT on the uniform cents per kWh basis would reduce any subsidies among classes and stated his belief that it was also done in this manner in the last DEP case. Tr. vol. 22, 146. Public Staff witness Floyd advocated for using witness Pirro's original methodology that returned the EDIT to classes based on how much each class had paid. He said that his proposed method was fairer, as industrial customers would receive more than they had paid if the CIGFUR Stipulation method is used. Tr. vol. 18, 334.

The Commission declines to adopt Section IV of the CIGFUR Stipulation because it will not achieve just and reasonable rates, and therefore is not in the public interest. As the substantial evidence shows, EDIT results from the overpayment of taxes by customers paying rates that include as a portion of the rate charges to cover the utility's anticipated federal and state income taxes. In addition, the amount of those overpayments is determinable from the Company's books and records of customer billing revenues. While different customer classes may have different rates of return (ROR), these RORs are highly dependent on the cost-of-service allocation methodology utilized, as well as the time period during which the cost-of-service study was conducted. As such, subsidy/excess issues should be resolved on the basis of equity between customer classes and their relationship to the overall ROR, not by favoring one class of customers by returning to them more than they paid in EDIT.

While in prior rate cases for DEC and DEP, use of a uniform EDIT rate to allocate state EDIT was agreed to as part of a settlement,[13] no party contested the issue in those cases, and the Commission accepted the settlement terms on state EDIT without making detailed findings of fact as to the appropriateness of a uniform rate. However, in the Commission's recent order in Docket No. E-22, Sub 562, of which the Commission has taken judicial notice in this proceeding, the Commission approved the provision of the stipulation between Dominion Energy North Carolina (DENC) and the Public Staff that the EDIT Rider credit should be allocated to customer classes based upon North Carolina basic (non-fuel) rate revenue annualized reflecting current rates for 2018. Order Accepting Public Staff Stipulation in Part, Accepting CIGFUR Stipulation, Deciding Contested Issues, and Granting Partial Rate Increase, *Application of Virginia Electric and Power Co., d/b/a Dominion Energy North Carolina for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina*, No. E-22, Sub 562, at 60-63 (N.C.U.C. Feb. 24, 2020), *appeal docketed*, No. 477A20 (N.C. Nov. 16, 2020)

With this issue now squarely before the Commission, the Commission finds it inappropriate to address any subsidy issues through reassignment of EDIT. The Commission gives substantial weight to the testimony of Public Staff witness Floyd that returning EDIT credits by customer class is a more equitable method by which to return EDIT. Thus, the Commission concludes that in this case it is inappropriate to refund the unprotected EDIT and provisional revenues to customers through the EDIT rider on a uniform cents per kWh basis and that rather these items should be refunded as a levelized EDIT credit by specific customer-class divided by the adjusted class test year sales.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 49-50

Cost Allocation Methodology

The evidence supporting these findings of fact is found in the verified Application and Form E-1; the Public Staff Second Partial Stipulation and CIGFUR Stipulation; the testimony and exhibits of DEC witnesses Hager and Pirro, Public Staff witness McLawhorn and Floyd, CIGFUR witness Phillips, and NCJC et al. witness Wallach; and the entire record in this proceeding.

Summary of the Evidence

DEC Direct Testimony

DEC witness Hager testified that the purpose of the cost-of-service study is to align the total costs incurred with jurisdictions and customer classes responsible for the costs and that cost causation is a key component in determining the appropriate assignment of revenues, expenses, and rate base among jurisdictions and customer classes. Witness

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[13] In DEC's last rate case, Sub 1146, federal EDIT was deferred until the next rate case or three years, whichever was sooner. In DEP's last rate case, Sub 1142, federal EDIT was not addressed because DEP filed its rate case before the Tax Act was signed into law in December 2017 (and effective January 1, 2018); the DEP Rate Order in Sub 1142 was issued on February 23, 2018.

Hager testified that costs are classified according to their cost-causation characteristics and that these characteristics are typically defined as demand-related, energy-related, or customer-related. The cost-of-service study supporting the Company's proposed rate design in this proceeding allocates the demand-related production and transmission costs based upon a jurisdiction's and customer class' coincident peak responsibility occurring during the summer, otherwise known as the Summer Coincident Peak (SCP) cost allocation methodology.

Witness Hager testified that distribution costs are classified as either demand-related or customer-related. Witness Hager summarized different methodologies for determining the customer-related component of distribution costs and testified that DEC used the "Minimum System" methodology in its cost-of-service study (COSS) for allocating costs to customers. Witness Hager testified that this method is appropriate for allocating customer-related distribution costs. After the customer-related costs are determined, the remainder of distribution costs are classified as demand-related and are allocated based on Non-Coincident Peak (NCP) Demand.

Witness Hager further testified to DEC's use of the MSM and stated that every customer requires some minimum amount of wires, poles, transformers, etc. to receive service; therefore, every customer caused DEC to install some amount of the distribution assets. According to witness Hager, the concept DEC used to develop its Minimum System Study was to consider what distribution assets would be required if every customer had only some minimum level of usage (e.g., one light bulb).

Witness Hager stated that the reason NCP is used for allocating demand-related distribution costs is that distribution facilities serve individual neighborhoods, rural areas, and commercial districts. They do not function as a single integrated system in meeting system peak demand. Instead, the distribution system serving each neighborhood, rural area, or commercial district must be able to meet the peak demand in the area it serves whenever the peak occurs. Witness Hager stated that contribution to NCP is the appropriate measure of determining customers' responsibility for these costs because it best measures the factors that drive investment to support that part of the system.

Witness Hager testified that all costs must be allocated to the appropriate jurisdiction and customer class; if any costs are omitted or remain unallocated then the utility's rates will not allow for full recovery of the Company's operating expenses, including its approved cost of capital. Further, she testified that once all costs and revenues are assigned, the COSS identifies the return on investment the Company has earned for each customer class during the test period. These returns can then be used as a guide in designing rates to provide the Company an opportunity to recover its costs and earn its allowed rate of return.

DEC witness Pirro testified that the base rate increase has been allocated to the rate classes on the basis of rate base. According to witness Pirro, this allocation methodology distributes the increase equitably to the classes while gradually moving each class's deficiency or surplus contribution to return to the retail average rate of return, within a band of reasonableness of +/- 10 percent, if possible.

Public Staff Direct Testimony

The Public Staff recommended using Summer/Winter Peak & Average (SWPA) instead of SCP. Public Staff witness McLawhorn testified that SWPA more accurately and fairly reflects the planning and operation of DEC's production plant to meet the energy needs of its customers.

The Commission ordered the Public Staff to file testimony addressing, as a minimum, SCP, Winter Coincident Peak (WCP), and SWPA cost-of-service methodologies. Witness McLawhorn's testimony includes an analysis of the impact of these cost-of-service methodologies across each of the retail classes of customers. Witness McLawhorn's discussion includes a comparison of class revenue increases for three of the methodologies (SCP, WCP, and SWPA).

Public Staff witness Floyd testified that the Public Staff believes that assignment of a proposed revenue change, whether it is an increase or a decrease, should be governed by four fundamental principles. Using the ROR as determined by the COSS, and incorporating all adjustments and allocation factors associated with the proposed revenue change, the Public Staff seeks to:

(1) Limit any revenue increase assigned to any customer class such that each class is assigned an increase that is no more than two percentage points greater than the overall jurisdictional revenue percentage increase, thus avoiding rate shock;
(2) Maintain a +/-10% "band of reasonableness" for RORs, relative to the overall jurisdictional ROR such that to the extent possible, the class ROR stays within this band of reasonableness following assignment of the proposed revenue changes;
(3) Move each customer class toward parity with the overall jurisdictional ROR; and
(4) Minimize subsidization of customer classes by other customer classes.

Witness Floyd testified that the Company's assignment of its proposed revenue increase does not adhere to the Public Staff's recommended principles outlined above. Further, witness Floyd noted that the Public Staff intends to update its recommended jurisdictional revenue requirement and file supplemental testimony to provide a final recommendation on its recommended revenue change. Witness Floyd stated that he will provide the Public Staff's assignment of proposed revenue change at that time.

CIGFUR Direct Testimony

CIGFUR witness Phillips recommended using WCP to reflect the fact that DEC now plans its generating system based on its winter peak demand. Witness Phillips stated that it is appropriate to classify all production investment as demand related. He argued that the capital costs are not a function of the number of kWh generated but are fixed and therefore are properly related to system demands, not to kWh sold. Witness Phillips stated that these costs are fixed in that the necessity of earning a return on the investment, recovering the capital cost (depreciation), and operating the property are related to the existence of the property and not to the number of kWh sold. According to witness Phillips, if sales volumes change these costs are not affected but continue to be incurred, making them fixed or demand-related in nature. He concluded that investment in generation plant is properly classified as a demand-related cost.

Further, witness Phillips contended that if an attempt were made to increase the allocation of investment to one group of customers, on the theory that those customers benefit more than others from the lower energy costs that result from the operation of a base load plant as opposed to a peaking plant, as done in the SWPA method, the analysis should be carried to its logical conclusion. The logical conclusion, according to witness Phillips, would be to fairly and symmetrically allocate energy costs to the group of customers who are forced to bear the higher capital costs allocated to them on a kWh basis. Witness Phillips stated that energy costs allocated to the high load factor class should recognize lower operating costs which result from the higher capital costs of the base load plants. Finally, he stated that the SWPA method fails to allocate lower than average fuel costs to the high load factor customers.

CIGFUR witness Phillips testified that he agrees with DEC's COSS with respect to the allocation of certain distribution facilities. According to witness Phillips, the Public Staff concluded in its March 2019 report that the use of the Minimum System Method for classifying and allocating distribution costs is reasonable.

NCJC et al. Direct Testimony

NCJC et al. witness Wallach provided extensive testimony on the cost-of-service topic. Witness Wallach testified that the Company's COSS misallocates distribution costs partly by misclassifying a portion of such costs as customer-related by relying on a flawed minimum system analysis. Witness Wallach testified that the Company's COSS allocates more distribution plant costs to the residential rate classes than is appropriate under generally accepted cost causation principles. Further, witness Wallach suggested that the Commission should direct DEC to discontinue its use of the MSM and instead rely on the "basic customer method."

In its 2018 DEC Rate Order, the Commission ordered the Public Staff to facilitate discussions with the electric utilities to evaluate and document a basis for continued use of minimum system and to identify specific changes and recommendations as appropriate. The Public Staff submitted its report on March 28, 2019, in Docket No. E-100, Sub 162. In its report the Public Staff concluded that use of the MSM by electric utilities for the purpose of classifying and allocating distribution costs is reasonable for establishing the maximum amount to be recovered in the fixed or basic customer charge.

The basic customer method referenced by witness Wallach accounts for meters, service drops, and certain other related costs. These typically would not include transformer or wires costs. Witness Wallach referred to a report (manual) recently produced by the Regulatory Assistance Project (RAP) entitled *Electric Cost Allocation for* *a New Era*. The report states that "The basic customer method for classification is by far the most equitable solution for the vast majority of utilities."

After the Company determines the customer-related costs using the Minimum System Method, the remainder of distribution costs are classified as demand-related and are allocated based on Non-Coincident Peak Demand. Witness Wallach recommended that the Commission reject the Company's use of the non-coincident peak demand allocator to allocate distribution costs. According to witness Wallach, the non-coincident peak allocator fails to accurately reflect usage patterns of residential customers and causes distribution costs to be over-allocated to the residential classes. Witness Wallach stated that to reasonably account for the effect of load diversity on distribution equipment sizing and cost, demand-related distribution costs should be allocated to rate classes on the basis of each class's diversified peak demand.

DEC Rebuttal Testimony

Witness Hager discussed some of the reasons DEC supports the SCP methodology:

(1) The application of the summer peak load to allocate demand-related production and transmission costs is consistent with the Single Coincident Peak Method identified in the NARUC Electric Utility Costs Allocation Manual;
(2) The predominance of the summer peak in DEC's service territory;
(3) The historical significance of the summer peak in DEC's expansion planning such that the majority of DEC's embedded generation fleet was built in response to summer peaks, thus making it appropriate to allocate these historically incurred costs;
(4) The benefit of a cost allocation methodology that encourages the shifting of usage to off-peak times;
(5) The value of sending consistent pricing signals by using a method that has been approved by this Commission for many years; and
(6) The importance of a consistent cost allocation methodology among DEC's jurisdictions so that the Company does not under- or over-recover its costs.

Further, witness Hager noted that she does not agree with witness McLawhorn's assertion that the SCP methodology only addresses the peak requirement of the capacity expansion planning process and places no value on the plants' requirement to produce energy at any time other than the peak hour. Witness Hager stated that this is not the complete picture. She explained that in developing a cost-of-service study, production costs are classified into demand and energy related costs. According to witness Hager, plant capacity is considered fixed to meet demand and therefore, the cost of plant capacity was assigned to customers on the basis of their contribution to the summer coincident peak. Plant output in terms of kWh generation varies with the system energy requirements; therefore, all variable costs of production are assigned to customers based on their energy usage. Witness Hager commented that in supporting the SWPA methodology, witness McLawhorn fails to acknowledge that the cost-of-service study in this proceeding already classifies over $2 billion of production costs (fuel, purchased power, O&M, etc.) as variable, and allocates these costs to the jurisdiction and customer classes using an energy allocator. Witness Hager stated that the SWPA method would allocate a higher portion of the fixed costs to the higher load factor customers. According to witness Hager, advocates for this method feel this is equitable on the theory that high load factor customers benefit from the lower energy costs that result from the operation of base load plants as opposed to the higher energy costs of peaking plants. However, witness Hager stated that proponents never carry this argument to its logical conclusion. That is, those customers allocated the higher capital costs based on energy usage, should be allocated the lower variable operating costs of those same base load facilities. Witness Hager noted that if the primary theory behind the use of the SWPA allocation methodology is that fixed production plant costs are incurred to meet both capacity and energy requirements, then consideration should also be given to the variable operating costs. She commented that it seems only fair and equitable that high load factor customers should be allocated more of the lower variable energy costs, while low load factor customers should be allocated more of the higher variable energy costs.

Witness Hager testified that she does not agree with witness Phillips' recommended use of the winter peak for the allocation of demand-related production and transmission costs. Witness Hager stated that the generation and transmission asset costs to be recovered in this proceeding were constructed based upon customers' contribution to the summer coincident peak. Therefore, SCP is the appropriate allocation methodology. Witness Hager also expressed concerns with the volatility of the winter peak and the volatility that using a single winter peak could introduce into customer rates.

Witness Hager next turned her attention to Minimum System. She stated that the NARUC cost allocation manual specifically states in the section on allocation of embedded costs that "the number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility's system." She stated that witness Wallach contends that customer connection costs are generally limited to plant and maintenance costs for a service drop and meter, along with meter reading, billing, and other customer-service expenses. Witness Hager noted that witness Wallach quotes Bonbright's Principles of Public Utility Rates to support his argument and noted that the text states that metering and billing expenses are the most obvious examples of customer costs. She commented that witness Wallach failed to mention that the quoted text does not say these are the only costs. Further, witness Hager stated that while it is true that Bonbright recognizes the difficulty of determining the proper allocation for the minimum system costs, he concludes that the exclusion of minimum system costs from demand-related costs is on "much firmer ground" than its exclusion from customer costs. According to witness Hager, Bonbright recognizes that utilities must distribute all costs among the classes of customers in a fully distributed cost analysis. Witness Hager stated that even more important, is the NARUC cost allocation manual that was developed after Bonbright's work. She commented that the cost allocation manual moved from the theoretical world of Bonbright to the reality of utilities' needs to move from development of revenue requirements to rate structures.

Stipulations

The CIGFUR Stipulation provides that prior to the Company's next general rate case the stipulating parties agree to meet to discuss potential cost-of-service methodologies that the Company may recommend for the purpose of allocating production and transmission costs. In addition, in its next general rate case, the Company shall also file the results of a class cost-of-service study with production and transmission costs allocated on the basis of the Summer/Winter Coincident Peak method and consider such results for the sole purpose of apportionment of the change in revenue to the customer classes. Further, the stipulation states that in its next general rate case, the Company will adjust its peak demand to remove curtailable/non-firm load, even if it does not call the load. If the Commission approves this adjustment in the Company's next general rate case, then DEC will propose use of this adjustment in its next subsequent rate case. Finally, the stipulation states that in its next three general rate cases DEC agrees to propose to allocate distribution expenses using the minimum system approach; however, if the Commission orders a different approach be used in the current rate case or either of the next two rate cases, DEC may elect to propose the minimum system approach in the next subsequent rate case after the denial, but DEC is not obligated to do so.

The Public Staff Second Partial Stipulation states that for this case only the Public Staff accepts, subject to the conditions in Section IV.B. below, the Company's proposal to calculate and allocate the Company's cost of service based on a SCP methodology. However, the Second Partial Stipulation also states that this provision shall not constitute precedent and shall have no effect on the Rate Design Study proposed by the Public Staff and agreed to by the Company. Further, Section IV.B. states that DEC has based its filing in this docket on the SCP methodology for cost allocation among jurisdictions and among customer classes. However, the stipulating parties agree that prior to the filing of its next general rate case the Company shall undertake an analysis of additional cost-of-service studies subject to the following conditions:

(1) The Company agrees to analyze and develop cost-of-service studies based on each of the following methodologies:

   a. Single Summer Coincident Peak;
   b. Single Winter Coincident Peak;
   c. One that utilizes the four highest monthly system peaks (two monthly peaks in summer and two monthly peaks in winter);
   d. SWPA;
   e. Base Intermediate and Peak (as described in the RAP "Electric Cost Allocation for a New Era" Manual, published January 2020); since the Company's accounting systems do not have the data developed to produce such a study, this method may be analyzed by looking at how it has been used at another utility or with a higher level hypothetical analysis;
   f. One that utilizes the 12 highest monthly system peaks in the test year; and

g. Any other identified relevant methodologies.

(2) Each methodology studied will include an evaluation of the allocation of the functions of utility service (production plant, transmission plant, distribution plant, and customer costs), including an identification of which cost components associated with these functions of utility service are fixed, and which are variable costs of service. The above methodologies only impact production and transmission allocations; however, the cost-of-service studies will show the allocation of all functions. For purposes of these studies, all demand and customer classified costs can be designated as fixed, and all energy classified costs can be designated as variable.

(3) Each methodology studied will include an evaluation of its strengths and weaknesses on both a jurisdictional and class allocation basis.

(4) Included in the studies shall be a discussion of how the allocation of fuel and other variable O&M expenses align with system planning.

(5) The Company shall consult with the Public Staff and any other interested parties throughout the study process.

Further, the Second Partial Stipulation states that the Company will continue to file annual cost-of-service studies based on both the SCP and SWPA methodologies until instructed to do otherwise by the Commission. The Company also agrees that it will not cite Commission approval of the Second Partial Stipulation as support for approval of the SCP methodology in future proceedings.

Discussion and Conclusions

The Commission gives significant weight to the testimony of DEC witness Hager and determines that having the necessary generation and transmission resources to meet the Company's summer peak, plus an appropriate reserve margin, is an essential planning criterion for the Company's system. Under cost causation principles all customer classes should share equitably in the fixed production and transmission costs of the system in relation to the demands they place on the system at the peak.

Although the Public Staff has traditionally supported the SWPA methodology, it is not unreasonable for the Public Staff to have agreed to the use of SCP in this proceeding. The Commission gives significant weight to the Public Staff's Second Partial Stipulation.

Further, the Commission gives significant weight to witness Hager's testimony concerning the Company's long history of employing the Minimum System Method and the Method's alignment with cost causation principles. According to witness Hager's testimony, after the Company determines the customer-related costs using the MSM, the remainder of distribution costs are classified as demand-related and are allocated based on NCP demand. Witness Wallach recommended that the Commission reject the Company's use of the NCP demand to allocate distribution costs. The Commission gives little weight to witness Wallach's argument for this position. The Commission gives more weight to witness Hager's testimony that NCP is the appropriate measure for determining customers' responsibility for these costs.

Finally, as discussed more fully later in this Order, the Commission concludes that the provisions of the CIGFUR Stipulation that commit DEC to take specific positions on certain issues in DEC's next several rate cases, such as adjustments to peak demand and use of the minimum system approach, are not relevant to any issue before the Commission in this docket. Under the guidelines set forth in *CUCA I and II*, a nonunanimous stipulation is evidence; however, the Commission can only use relevant evidence as the basis for its decisions. The CIGFUR Stipulation and DEC agreements on future proposals and positions in future rate cases have no relevance in this rate case, and the Commission therefore declines to accept those portions of the CIGFUR Stipulation.

Based on the evidence in this proceeding, including the stipulations, the Commission finds and concludes that the greater weight of the evidence shows that the SCP cost-of-service methodology provides the most appropriate methodology to assign fixed production and transmission costs in this proceeding.

The Commission finds and concludes that the Second Partial Stipulation was entered into by the parties after substantial discovery and negotiations, and that it represents a proposed negotiated resolution of the matters in dispute in this docket. As a result, the Second Partial Stipulation is material evidence to be given appropriate weight in this proceeding.

Moreover, as a demonstrated by the opposing testimony between DEC and CIGFUR witnesses, the Commission finds and concludes that the CIGFUR Stipulation is the product of the give-and-take between the parties during their settlement negotiations in an effort to appropriately balance DEC's usage of the SCP and CIGFUR's desire to investigate a different methodology for the sole purpose of apportionment of the change in revenue to the customer classes in the next general rate case. The Commission finds and concludes that the CIGFUR Stipulation was entered into by the parties after substantial discovery and negotiations, and that it represents a proposed negotiated resolution of the matters in dispute in this docket. As a result, the provisions of the CIGFUR Stipulation not otherwise rejected by the Commission are relevant and material evidence to be given appropriate weight in this proceeding.

Moreover, the Commission concludes that the Company's use of the MSM for cost allocation in this proceeding is just and reasonable to all parties in light of all of the evidence presented. Further, the Commission concludes that NCP is the appropriate measure for determining customers' responsibility for demand-related distribution costs after the customer-related costs are determined using the MSM.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 51

Rate Design

The evidence supporting this finding of fact is found in the verified Application and Form E-1; the stipulations between DEC and various parties; the testimony and exhibits of DEC witnesses Pirro, Reed, Huber, and Hager, Public Staff witness Floyd, NCJC et al.

witnesses Wallach and Howat, NCSEA witness Barnes, Harris Teeter witness Bieber, and CUCA witness O'Donnell; and the entire record in this proceeding.

Summary of the Evidence

DEC Direct Testimony

DEC witness Pirro testified that when moving rate schedules and riders closer to a more cost-justified basis, it is important to consider the impact upon customers and to employ the principle of "gradualism." Witness Pirro stated that this principle was applied in this proceeding to update price relationships and levelized the percentage change in revenues on participants within the rate class while still moving towards a more equitable pricing structure.

Witness Pirro testified that the Company is not proposing any new peak time pricing rate designs offering real time price signals in this proceeding. Witness Pirro stated, however, that the Company is implementing nine new dynamic pricing pilots effective October 1, 2019 in compliance with the Commission's 2018 DEC Rate.

Witness Pirro testified that the Company's unit cost study indicates it is appropriate to raise the monthly BFC to better reflect all customer-related costs. He indicated that to do otherwise would result in customer cross-subsidization. Witness Pirro stated that the Company would normally propose the BFC for all rate classes be set to recover approximately 50% of the difference between the current rate and the full customer-related unit cost incurred to serve the customer groups. However, according to witness Pirro, the Company decided in this rate case proceeding not to increase the BFC, but rather to leave it at current rates due to past concerns raised by low-income and other advocates with respect to the level of the charge.

Further, witness Pirro stated that the Company is requesting that a collaborative stakeholder process be formed to discuss opportunities to address low-income, fixed-income and low-usage customer concerns. Once the Company has the benefit of that collaborative process, the BFC will be addressed in a future proceeding to properly reflect equitable cost-based rates that provide accurate price signals to customers.

DEC witness Reed adopted the testimony of Marc Arnold and testified regarding the rate design for the Company's 17 outdoor lighting products and services. Witness Reed's testimony expanded on witness Pirro's testimony. Witness Reed stated that the Company re-evaluated the outdoor lighting transition fee charged to customers who move from metal-halide and high-pressure sodium lights to LED (light-emitting diode). According to witness Reed, the Company proposes to lower the transition fees to balance take-rates while protecting the rate class from premature retirement of assets.

Public Staff Direct Testimony

Public Staff witness Floyd testified that the Company made very few modifications to any of its rate schedules other than to increase individual rate elements within each schedule to accomplish the revenue increase assigned to the rate class itself. However, witness Floyd stated that notwithstanding his testimony highlighting the status quo nature of the Company's rate schedules, he is generally supportive of the few proposed changes to rate schedules and service regulations as discussed by witnesses Pirro and Reed. Witness Floyd noted that the Company proposed changes to its lighting rate schedules, Rider MRM, and certain fees in its service regulations.

Witness Floyd testified that the Company has not utilized AMI data to develop new rate designs or inform the existing rate designs. Witness Floyd referenced his testimony in the Sub 1146 proceeding where he highlighted the Company's commitment to exploring and developing new rate designs once smart meters were fully deployed and data from those meters became available. According to witness Floyd, that time has arrived. He stated that the Company should begin incorporating AMI data into its load research efforts supporting both rate design and integrated resource planning. He recommended that the Commission order a comprehensive rate design study and suggested rate design questions to be addressed.

Witness Floyd testified that is appropriate for the Company to begin working on new EV rate designs now and to discuss those designs with stakeholders as they are considered and developed. He proposed that the Commission require DEC to develop and propose EV rate designs as part of the larger rate design study recommended.

Witness Floyd stated that the Public Staff does not object to the Company's proposal to leave the BFC at current levels for purposes of this proceeding.

Finally, witness Floyd testified that the Public Staff supports convening a stakeholder process to address affordability issues, including the appropriate amount of the BFC.

NCJC et al. Direct Testimony

Witness Wallach recommended that the Company's request to maintain the residential BFC at its current rate of $14.00 per bill be denied. He instead recommended that the residential BFC be reduced to $11.15 per bill. Witness Wallach testified that it is unreasonable for DEC to recover costs through the residential BFC that were classified as "customer-related" using a minimum-system analysis. Further, witness Wallach noted that once the excess uncollectible and customer-related distribution costs from the minimum-system analysis are removed, he estimates that a residential BFC of $11.15 would recover the truly customer-related costs of meters, service drops, and customer services allocated to the residential rate classes. Witness Wallach stated that to the extent that usage-driven costs are recovered through the fixed customer charge rather than through the volumetric energy rate, residential customers with below-average usage bear a disproportionate share of usage-driven costs and consequently subsidize customers with above-average usage. Witness Wallach attempted to characterize this subsidization in his testimony.

Witness Howat also recommended that the Commission reject the $14.00 residential BFC and approve the $11.15 BFC proposed by witness Wallach.

NCSEA Direct Testimony

NCSEA witness Barnes provided extensive testimony on his proposal that the Commission direct DEC to establish EV specific rates for both home charging and commercial charging applications. Witness Barnes recommended that the Commission direct DEC to file separate, targeted EV-specific tariffs for both residential and nonresidential dedicated EV charging, reflecting the core characteristics discussed in his testimony. He stated that this should occur within 60 days of the order in this rate case.

Further, witness Barnes recommended that the Commission establish an investigatory docket to receive further information and permit further discussion of EV-specific rates, lessons learned, and potential refinements.

Harris Teeter Direct Testimony

Witness Bieber recommended modifications to the proposed OPT-VSS rate design that he opined would improve the alignment between the rate components and the underlying costs while employing the principle of gradualism and mitigating intra-class rate impacts. This rate schedule is a time of use rate class that provides separate rates for customers of varying size and delivery voltage. Witness Bieber noted that according to witness Pirro, the Company designed its commercial and industrial rates utilizing a uniform percentage increase method, which seeks to allocate the additional cost recovery across the various components of each schedule. According to witness Bieber, witness Pirro claims that this method maintains the overall structure of the rate without distortion relative to the historical rate design. Witness Bieber stated that he fundamentally disagrees with the proposed use of a uniform percentage increase method because it is not consistent with the cost causation drivers. Further, DEC proposes to increase the rate OPT-VSS energy charges by more than 9%, while according to the Company's own unit cost-of-service study, the proposed energy-related costs for rate OPT-VSS increased by less than 2%. Witness Bieber testified that DEC's proposed rate design under-recovers the demand-related charges while over-recovering the energy-related charges.

CUCA Direct Testimony

CUCA witness O'Donnell testified that the Commission should require DEC to immediately convene meetings with the Company's large customers to ascertain and offer new interruptible rates to its large customers no later than January 1, 2021.

DEC Rebuttal Testimony

DEC witness Huber stated that changes in customer interests, political and regulatory priorities, and increasing adoption of new technologies demand a rethinking of DEC's rate designs. He agreed that the Company should conduct a comprehensive rate design study. Further, witness Huber proposed that DEC complete the study by the end of the second quarter of 2021.

Witness Huber stated that the Company cannot cost-effectively implement any rate design changes until the new Customer Connect billing system is in use. Because it is more cost-effective to implement new rates concurrently with the new billing system, DEC strongly favors utilizing the time prior to implementation to analyze data, convene stakeholders, and refine its proposals. According to witness Huber, Customer Connect is scheduled to be implemented for DEC in the spring of 2021. Once the new Customer Connect system is fully deployed and post-deployment stabilization is achieved approximately six months later, the Company will be ready to begin implementing new rate designs.

Further, witness Huber stated that increasing the adoption of EVs is a state policy goal that could provide significant system benefits and a study of rate designs that facilitates the adoption of electric vehicles will be a part of any comprehensive rate design study.

Witness Pirro noted that the Company's Rate Schedule OPT-V is well received and very popular among the commercial and industrial customer base as it offers variation in pricing to incent changes in usage behavior. According to witness Pirro, the Company, in Docket No. E-7, Sub 1026, filed DEC's OPT rate schedule criteria. The redesign of OPT was fully vetted and agreed upon by both CUCA and CIGFUR and approved by the Commission. The Company diligently pursued a fair and equitable cost-based resolution, as all subsidy/excess revenues were eliminated within the OPT class. Witness Pirro stated that the approved redesign ultimately focused the increase to the on-peak portion of the rate in order to send a stronger price signal for off-peak usage.

Witness Pirro stated that he does not agree with proposed changes to the OPT-V rates. He commented that the witnesses appear to be supportive of cost-based rate design. However, witness Pirro stated that the witnesses miss an important translation between cost of service and rate design. According to witness Pirro, rate design needs to look at the rate structure and provide balance (customer, demand, and energy) to provide an accurate price signal to customers. The rate designer's task is to design a rate that best mimics the cost of serving customers across a range of usage without all cost elements being strictly defined by the rate structure. Further, witness Pirro noted that an industry method used to accomplish this is to allocate a portion of demand costs to be included in the energy charge. He stated that the simplistic notion that all demand costs be included in a demand charge and all energy costs be included in an energy charge would essentially invalidate most of the rate structures in the industry across the country. Further, according to witness Pirro, if rates increase, more and more costs would be unjustifiably borne by the lower load factor customers in the group with the methods advocated by the intervenors. Finally witness Pirro stated that this would decrease their competitiveness and cause real economic harm, while their higher load factor counterparts enjoy the results of a mispriced product.

Witness Pirro stated that he disagrees with the intervenors that allege costs identified by the Minimum System Methodology are not customer costs and should be excluded from the BFC. He noted that the Company's COSS indicate that these costs are customer costs and, therefore, the BFC was designed to recover them. Further, witness Pirro commented that the primary residential rate schedule does not have a demand component; rather, it only has a BFC and a volumetric per kWh charge. He testified that it would be inappropriate to shift costs currently included in the BFC to a volumetric rate. He stated that failing to properly recover customer-related costs via a fixed monthly charge would provide an inappropriate price signal to customers and would fail to adequately reflect cost causation. Shifting customer-related costs to a volumetric per kWh rate further exacerbates this concern and overcompensates energy efficiency and distributed generation for the cost avoided by their actions, thereby skewing the market for such measures.

Witness Hager stated in her rebuttal testimony that the Public Staff made several observations regarding setting the BFC. For example, she noted that the Public Staff differentiates between the considerations in a COSS and Rate Design, the latter of which the Public Staff states should take additional things into consideration such as policy objectives and appropriate price signals. Witness Hager testified that similar to the Public Staff, she believes it is appropriate to keep a COSS free of biases and focus on cost causation.

Stipulations

The CIGFUR Stipulation states that should the Company independently undertake or should the Commission order a comprehensive rate design process prior to the Company's next general rate case, the Company agrees to explore the following: (1) a rate schedule targeted at high load users similar to Duke Energy Indiana's HLF rate, (2) allowing customers to move existing load to the existing HP Hourly Pricing rate, and (3) an emergency demand response program similar to Southern California Edison's Time-of-Use Base Interruptible Program (TOU-BIP) tariff. If there is mutual agreement between CIGFUR and the Company on the terms of any of the above referenced rates and CIGFUR indicates that at least one of its member customers is willing to take service under such rates, the Company agrees to file said rates with the Commission for approval in its next rate case filing.

Further the CIGFUR Stipulation states in the event that the Commission does not order or DEC does not independently undertake a comprehensive rate design process prior to its next general rate case, then prior to its next general rate case the Company agrees to consult with CIGFUR on: (1) a rate schedule targeted at high load users similar to Duke Energy Indiana's HLF rate, (2) allowing customers to move existing load to the existing HP-Hourly Pricing rate, and (3) an emergency demand response program similar to Southern California Edison's TOU-BIP tariff. If there is mutual agreement between CIGFUR and the Company on the terms of discussed rates and CIGFUR indicates that at least one of its member customers is willing to take service under such rates, the Company agrees to file said rates with the Commission for approval in its next rate case filing.

The Commercial Group Stipulation as well as the Harris Teeter Stipulation state that the Commercial Group and DEC agree that the OPT-VSS off-peak energy charge shall be set at 3.0222 cents/kwh and the on-peak energy charge shall be increased by a percentage amount that is equal to half of the overall percentage increase for the OPT-VSS rate schedule. The demand charges for the OPT-VSS rate schedule shall be adjusted by the amount necessary to recover the final OPT-VSS revenue target. Both stipulations state that GIP costs allocated to OPT-V customers shall be recovered via OPT-V demand charges.

The Public Staff Second Partial Stipulation states that:

(1) The Company agrees that any proposed revenue change will be apportioned to the customer classes such that:
  a. With the exception of DEC's lighting customer class where the ROR falls significantly below the overall North Carolina retail ROR, any revenue increase assigned to any customer class is limited to no more than two percentage points greater than the overall jurisdictional revenue percentage increase, thus avoiding rate shock;
  b. Class RORs are maintained within a band of reasonableness of +/-10% relative to the overall North Carolina retail ROR; for class RORs currently above the band of reasonableness, the Company will gradually move class RORs closer to the band of reasonableness;
  c. All class RORs move closer to parity with the North Carolina retail ROR;
  d. Subsidization among the customer classes is minimized.

(2) The stipulating parties agree that the proposed modifications to the Company's rate schedules are reasonable for purposes of this proceeding.

(3) The stipulating parties agree that the Commission should order a comprehensive rate design study.

Discussion and Conclusions

The Commission concludes that the Company's proposed portfolio of rate designs as modified by this Order, specifically including the rate design provisions outlined in §§ IV.C and D of the Public Staff Second Partial Stipulation, are just and reasonable for purposes of this proceeding. Nonetheless, as the Company and customers adopt new technologies and uses of the electric system change, rate design must evolve in order to maximize the efficiency and effectiveness of these new technologies and ensure usage of the electric system that is consistent with the public interest. The Commission recognizes the impact the results of a comprehensive rate study may have on future utility services, customers, and the economy of the State. That said, the Commission concludes that it is in the public interest to direct the Company to conduct a comprehensive rate design study (Rate Design Study) as outlined in § IV.E of the Second Partial Stipulation and further described in the testimony of witnesses Floyd and Huber, and as expanded upon herein. The Public Staff invited Commission guidance on scope and timeline of the study but emphasized that some flexibility is necessary to ensure robust discussion amongst stakeholders. Tr. vol. 18, 287. The Company agreed that broad stakeholder engagement is a necessary component of the comprehensive rate design process. Tr. vol. 13, 42. Based on the evidence in the record, the Commission provides the following guidance.

With respect to scope, the Rate Design Study should address, at a minimum, those rate design questions set forth in § IV.E(1)–(6) of the Second Partial Stipulation, including firm and non-firm utility services, various types of end uses (EVs, microgrids, energy storage, and DERs), the formats of future rate schedules, marginal cost versus average cost rate designs and pricing, unbundling of average rates into the various functions of utility services, and socialization of costs versus categorization of specific costs. The Rate Design Study should include but not be limited to these topics. The Commission is persuaded that in depth evaluation, debate, and discussion by and among stakeholders regarding cost to serve, rate design, and making the most efficient use of the electric system is necessary to achieve results that are in the public interest, and the Commission directs the Company to ensure that all necessary and appropriate topics are considered, to this end. For example, the Commission notes that § V.E of the CIGFUR Stipulation includes commitments by the Company in the event that the Commission directs the Company to undertake a comprehensive rate design study. Notwithstanding the foregoing, the Commission directs the Company and all parties that participate in the Rate Design Study to work cooperatively, productively, and efficiently to ensure that resources are efficiently expended on this endeavor and that the outcome aligns with the public interest.

In response to Commission questions, witness Huber confirmed that the issue of the rates and charges for services for net metering customers would be a part of the Rate Design Study. Tr. vol. 13, 94, 112-13. Thus, the Commission anticipates and expects that net metering will be considered in the Rate Design Study and that consistent with N.C.G.S. § 62-126.4(b), the Rate Design Study will address the costs and benefits of customer-sited generation.

With respect to the recommendations of NCSEA witness Barnes regarding EV charging rates, the Commission determines that the development of such rates is most appropriately evaluated in the context of the Rate Design Study as opposed to in a separate proceeding. Thus, the Commission directs the Company to include the investigation of EV rate designs in the Rate Design Study.

Similarly, with respect to the recommendations of CUCA regarding the development of interruptible rates for large industrial customers, the Commission concludes that the development of such rates is most appropriately evaluated in the context of the Rate Design Study.

Public Staff witness Floyd testified as to the relationship between cost-of-service studies and rate design. He testified that while rate design does not strictly follow cost-of-service studies in every instance, cost-of-service studies most definitely inform rate design. Tr. vol. 18, 341. The Public Staff takes the position that a cost-of-service study aligned with the current rate design portfolio of electric tariffs should be the beginning of the Rate Design Study. *Id*. The Public Staff envisions that the Rate Design Study would take the existing portfolio of rate schedules, including all current principles and policies that inform the current components, and calculate rates as close to a purely cost-based approach as possible. *Id*. The Public Staff envisions the following process: (1) conducting a load study using DEC's new AMI network; (2) ascertaining, through use of the load data, the distinguishing characteristics of customers and customer classes that would serve as the basis for a cost-of-service structure; and (3) building rate designs that allow customers some choice and flexibility in how they want to use energy, and develop new rate designs using the costs to serve those customers. Tr. vol. 18, 341-42. Public Staff witness Floyd testified that this exercise would provide insight and information to the Commission as to costs and impacts on customers of the various rate designs considered. The Commission agrees with the Public Staff that the exercise, as described by witness Floyd, should provide the Commission with critical information regarding load characteristics of customers and customer classes, associated costs, and impacts to customers that could be used to inform future decisions of the Commission. Thus, the Commission directs the Company to undertake the Rate Design Study through the process envisioned by witness Floyd.

Further, as recommended by Public Staff witness Floyd, the Commission finds that the Rate Design Study should: (1) include an analysis of each existing rate schedule to determine whether the schedule remains pertinent to current utility service, including whether the schedule should remain the same, be modified, or be replaced; (2) address the potential for new schedules to address the changes affecting utility service; (3) provide more rate design choices for customers; and (4) explore the feasibility of consolidating the rates offered by DEC and DEP. Tr. vol. 18, 283.

Company witness Huber indicated that the Company is open to a third-party facilitator for the stakeholder portion of the Rate Design Study. Tr. vol. 13, 42. The Commission agrees that the use of an independent facilitator would be appropriate and, thus, directs the Company to engage a third party for this purpose.

All parties to the rate case proceeding should be afforded the opportunity to participate as stakeholders in the Rate Design Study. The Commission directs the Company to initiate the Rate Design Study with stakeholders no later than 30 days following the issuance of this Order.

With respect to timing, as indicated by witness Huber's testimony that the Rate Design Study will yield a detailed "roadmap" within a year, the Commission directs the Company to file a comprehensive roadmap and timeline for proposing new rate designs and identifying areas for additional study within 12 months of this Order. In addition, the Commission directs the Company to file quarterly status reports in the instant docket, providing, in detail, the work of the Rate Design Study participants over the previous quarter, including objectives achieved, and anticipated work to be undertaken going forward, including objectives to be achieved.

Finally, the Commission recognizes that the Rate Design Study and the affordability collaborative described hereinafter are separate but parallel efforts. To the extent the parties participating in the affordability collaborative recommend the design of new rates to offer to low-income customers, the parties should present those recommendations to the rate design study participants for consideration. Additionally, the Commission does not intend for the stakeholder processes for affordability and the Rate Design Study to be mutually exclusive or contingent upon the completion of either stakeholder process.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 52–54

Affordability

The evidence supporting these findings of fact is found in the verified Application and Form E-1; the stipulations between DEC and various parties; the testimony and exhibits of DEC witnesses De May and Pirro, Public Staff witness Floyd, NCJC et al. witness Howat, and CBD/AV witness McIlmoil; and the entire record in this proceeding.

Summary of the Evidence

DEC Direct Testimony

DEC witness De May testified that DEC is committed to helping customers who struggle to pay for basic needs with programs and options to assist them during times of financial hardship. He outlined several existing programs that have helped many of their customers in this regard. Witness De May stated that DEC is convinced that more low-income energy assistance programs can be offered to aid customers in need of support. Further, he stated that stakeholder engagement is necessary to adequately develop an appropriate suite of effective options for the Commission to consider for approval. The Company requested that the Commission direct the Company to host, and the Public Staff to participate in, a collaborative workshop with interested stakeholders to address the establishment of new low-income programs.

Witness Pirro testified that the Company proposes to increase the monthly discount applicable to eligible customers taking service under Rate RS and Rate RE, receiving Supplemental Security Income (SSI) under the program administered by the Social Security Administration and who are blind, disabled, or 65 years of age or over. The discount was authorized by the Commission on August 31, 1978. The Company proposed to increase the maximum discount by approximately 10% to 11% to $3.25 for schedule RS and $3.14 for RE, per month.

Public Staff Direct Testimony

The Commission’s January 22, 2020 order in this docket directed the Public Staff to “investigate DEC’s analysis of affordability of electricity within its service territory as well as programs available to DEC’s customers that address affordability with a particular focus on residential energy customers." In the order the Commission directed the Public Staff to address the following issues:

(1) An overview of Lifeline Rates and whether this approach would be appropriate for North Carolina;
(2) The applicability, design, and effectiveness of the Company's SSI discount;
(3) A comparison of the SSI discount to other tariffs available to customers that address affordability issues;
(4) An overview of similar affordability tariffs or plans available by the other affiliates of DEC; and
(5) The merits of using a "minimum bill" concept in lieu of a fixed customer charge.

Public Staff witness Floyd addressed each of these issues in his testimony. Consistent with the Company's request as discussed by witness De May, witness Floyd stated that the Commission should order the convening of a stakeholder process that is tasked with addressing affordability issues for low-income residential customers.

NCJC et al. Direct Testimony

NCJC et al. witness Howat provided extensive testimony on issues related to affordability of electric service for DEC's lower-income residential customers and discussed programs and policies designed to mitigate affordability challenges faced by those customers. Witness Howat outlined policy objectives and program design elements featured in effective programs, provided brief descriptions of a sampling of investor-owned utility bill affordability programs operating in the U.S., and recommended that the Commission initiate a process culminating in approval of funding and implementation of enhanced low-income bill payment assistance programming and low-income residential energy-efficiency programming in the DEC service territory. Finally, witness Howat recommended that the Commission direct DEC to expand the Helping Home Fund and consider shifting it from a shareholder- to a ratepayer-funded program.

CBD/AV Direct Testimony

CBD/AV witness McIlmoil provided extensive testimony addressing the impacts that DEC's proposal to increase rates will have on low-income households, specifically on the home energy cost burden those households experience. Witness McIlmoil recommended that the increase in residential electric bills proposed in the present case, in the first year and over the following four years, must not only be considered by itself but also within the context of DEC's intention to shift more costs onto the residential class while increasing the monthly BFC. In that regard witness McIlmoil recommended that the Commission consider all of these factors, especially in light of its mandate to consider changing economic conditions and customers' ability to afford rate increases.

Further, witness McIlmoil testified that in addition to accepting and adopting his recommendations, that the Commission should encourage DEC to recognize and accept the definition and use of the phrase "energy burden," and make a more concerted and immediate effort to invest in low-income energy efficiency and demand-side management programs at a scale of investment sufficient to meet the scale of the energy problem among its low-income customers.

DEC Rebuttal Testimony

DEC witness Pirro stated that the Company is mindful of the impact of any rate increase on customers, particularly low-income customers; however, the Company does not design rates based on income, but rather applies cost causation principles to the extent practical. Further witness Pirro stated that there are other means of addressing the financial needs of low-income customers, such as Company, state, and local programs, which are more effective than biasing the rate design. However, witness De May stated that the Company supports a dialogue on ways to mitigate electricity costs for low-income customers. He stated that the Company looks forward to the opportunity to engage with its interested stakeholders in a collaborative workshop to address this important issue.

Stipulations

The NCSEA/NCJC et al. Stipulation states that the Company agrees to provide, in conjunction with the concurrent commitment of Duke Energy Progress, LLC (DEP), an aggregate combined shareholder-funded contribution to the Helping Home Fund of $3 million per year for two years (for a total of $6 million).

Further, the NCSEA/NCJC et al. Stipulation states that within six months of the effective date of the stipulation, in addition to the low-income collaborative proposed by DEC, the stipulating parties agree to collaborate to design additional low-income DSM/EE program pilots to present to the DEC and DEP DSM/EE Collaborative for consideration.

The Public Staff Second Partial Stipulation states that the stipulating parties agree that the Commission should order the Company to convene a stakeholder process that is tasked with addressing affordability issues for low-income residential customers, with a timeline for the process, including deadlines for periodic reporting and filing recommendations to the Commission. The stipulating parties propose one year for this process.

DEC witness De May discussed in his second settlement testimony how the partial settlement balances the Company's need for rate relief with the impact of such rate relief on customers. Witness De May stated that he attended public hearings held by the Commission in this matter and personally heard from many customers who are concerned about the impacts of any rate increase on their families and businesses. Witness De May stated that DEC is very mindful of these concerns. Further, he stated, in light of the current economic conditions of many customers due to the COVID-19 pandemic, the Company believes that the concessions the Company has made in the Second Partial Settlement fairly balance the needs of customers with the Company's need to recover substantial investments made in order to continue to comply with regulatory requirements and safely provide high quality electric service to customers. Witness De May stated that the

Company agreed to make an annual $2.5 million shareholder contribution to the Share the Warmth Program in 2021 and 2022, for a total contribution of $5 million.

Discussion and Conclusions

The Commission gives significant weight to the testimony of Public Staff witness Floyd addressing the affordability issues raised in the Commission's January 22, 2020 order.

In addition, the Commission gives weight to the extensive testimony of NCJC et al. witness Howat concerning affordability. Witness Howat's comments on the need for low-income affordability programs, policy objectives and program design elements featured in effective programs, as well as descriptions of investor-owned utility bill affordability programs are most informative.

The Commission also gives weight to the information provided in the late-filed exhibits of NCJC et al. which are sufficiently responsive to Commission questions posed during the hearing.

The Commission gives significant weight to the provisions of the NCSEA/NCJC et al. Stipulation and the Public Staff's Second Partial Stipulation discussed above, each of which recommend a stakeholder process that is tasked with addressing affordability issues for low-income residential customers.

Based on the evidence in this proceeding, including the stipulations, the Commission finds and concludes that it is appropriate for the Company to convene a stakeholder process (collaborative) that is tasked with addressing affordability issues for low-income residential customers, with a timeline for the process, including deadlines for periodic reporting and filing recommendations to the Commission. Both Company and intervenor witnesses highlighted the need for direction from the Commission in establishing the goals and parameters of the stakeholder process. The Commission takes note of the fact that Company witness De May attended the public witness hearings held in this proceeding and accepts his attendance as an indication of the Company's commitment to its customers in this endeavor.

Starting with and building upon witness Floyd's framework, the Commission directs that the collaborative should as part of its work:

(1) Prepare an assessment of current affordability challenges facing residential customers. The assessment should:

a. Provide an analysis of demographics of residential customers, including number of members per household, types of households (single family or multi-family), the age and racial makeup of households, household income data, and other data that would describe the types of residential customers the Company now serves. To the extent demographics vary significantly across the

Company's service area, provide additional analysis of these demographic clusters.

b. Estimate the number of customers who live in households with incomes at or less than 150% of the federal poverty guidelines (FPG), and those whose incomes are at or less than 200% of the FPG.

c. For the different demographic groups identified as part of a. and b., provide an analysis of patterns and trends concerning energy usage, disconnections for nonpayment, payment delinquency histories, and account writeoffs due to uncollectibility.

(2) Develop suggested metrics or definitions for "affordability" in the context of the Company's provision of service in its North Carolina service territory and explore trends in affordability. Questions to be answered include but should not be limited to:

a. How is "affordability" defined and applied in other jurisdictions particularly for those with similar legal and regulatory frameworks, i.e., vertically integrated investor-owned utilities?

b. What criteria (both qualitative and quantitative) should the Commission consider when determining who would be eligible for different types of affordability programs?

(3) Investigate the strengths and weaknesses of existing rates, rate design, billing practices, customer assistance programs and energy efficiency programs in addressing affordability. Questions that should be addressed include:

a. What defines a "successful program" and what metrics should be monitored and presented that show the impact of programs on addressing or mitigating affordability challenges?

b. What percentage of residential customers are eligible for each existing program and what percentage of eligible customers enroll in and/or take advantage of these programs?

c. What is the impact of existing programs on the energy burden for enrolled customers?

d. Should existing programs be maintained, replaced or terminated? If maintained, should any changes be made to improve results? If programs are replaced, what would replace them?

e. Are the following programs, in addition to any others agreed upon by the collaborative, appropriate for implementation in North Carolina and, if so, what statutory or regulatory changes are necessary to permit implementation: (1) minimum bill concepts as a substitute for fixed monthly charges; (2) income-based rate plans, such as Ohio's percentage of income payment plan; (3) segmentation of the existing residential rate class to take into account different levels of usage; (4) expanding eligibility for DEC's current SSI-based program to include additional groups of ratepayers; and (5) the inclusion of a specific component in rates to be used to fund supplemental support programs. Priority should be given to identifying affordability programs that comply with the current statutory framework, however the collaborative may describe high potential programs that have been successful in other jurisdictions but which would require statutory changes for implementation in North Carolina.

f. How do specific programs addressing affordability affect cost-causation and allowance of costs among classes?

g. How does cost-of-service allocation affect rate design and affordability of rates?

h. What, if any, practices and regulatory provisions related to disconnections for nonpayment should be modified or revised?

i. What existing utility and external funding sources are available to address affordability? Estimate the level of resources that would be required to serve additional customers

j. What are the opportunities (and challenges) of the utilities working with other agencies and organizations to collaborate and coordinate delivery of programs that affect affordability concerns?

The Commission does not intend this list of topics to be exhaustive or limiting in any manner. The Commission will look to the stakeholder process to provide information, guidance, and recommendations on the existing programs, future programs, and the mechanisms for funding that would be needed.

Within 90 days of the date of this Order, the Company and the Public Staff shall convene a collaborative for interested stakeholders to address the affordability of electric service for low-income customers. The collaborative should be facilitated by a third party with experience in affordability issues. The Company should solicit from interested stakeholders the names of individuals that should be invited to participate in the collaborative. As an example, interested stakeholders could include the Public Staff, the AGO, NCJC, NCHC, NAACP, AARP, Legal Aid of North Carolina, etc. Stakeholder groups that want to be directly represented in the collaborative's work should contact the Public Staff to signal their interest in participating. A final list of participants including support for their participation should be submitted to the Commission. After reviewing this recommended list, the Commission will either accept or suggest modifications to the list.

Within 180 days of the date of this order, the Company and the Public Staff shall file with the Commission a report (individually or jointly) that briefly summarizes progress to-date including any noteworthy interim findings or recommendations. Thereafter, progress reports are to be filed quarterly.

Within 12 months of the date of the first workshop, the Company and the Public Staff are required to file a joint final report with the Commission outlining the feedback and recommendations obtained in the collaborative, including any new programs, rate schedules, and funding mechanisms that have wide or consensus support of stakeholders. In addition to the report identifying stakeholder consensus, it should also identify programs that were studied and supported by a number of stakeholders but may not have reached full consensus.

The Commission will then issue a procedural order allowing for the public and interested parties to comment on the joint final report.

The collaborative recommendations should include a mix of proposed programs that can be implemented in the near term and those that will require additional lead time to implement due to complexities. For example, the Commission anticipates/expects concrete proposals that (a) include both elements of rate design and programs that can be layered on top of existing or future rate plans, (b) can be implemented by petition and proceedings prior to the next general rate case because the proposals do not include rate design changes, (c) will be proposed by DEC for consideration in its next general rate case, and (d) have been fully costed out.

The Commission does not intend the stakeholder processes for affordability and comprehensive rate design to be mutually exclusive or contingent upon the completion of either stakeholder process. If consensus is achieved on particular issues surrounding affordability, proposals may be brought forward for consideration as soon as practicable. Given the overlapping nature of the work of the energy efficiency collaborative, the proposed rate study effort, and the affordability collaborative, those working on the three efforts should, to the extent possible, stay abreast of and consider the ongoing work of the separate teams as they each carry out their work. At a minimum, each progress report should include a section that describes the major interactions and connections between the affordability collaborative and the rate study and energy efficiency stakeholder groups. The Commission recommends that to the extent appropriate, interim material produced from each of the three groups be made available to each of the other groups. The Commission recommends holding at least one in person or virtual joint meeting of the three groups to specifically identify and discuss key areas of concern.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 55–61

Storm Costs

The evidence supporting these findings of fact is found in the verified Application and Form E-1; the Public Staff First Partial Stipulation; the testimony and exhibits of DEC witnesses De May, Jackson, and McManeus and Public Staff witness Boswell; and the entire record in this proceeding.

Summary of the Evidence

In its Storm Cost Petition DEC sought approval from the Commission to defer certain storm repair costs incurred by the Company in responding to Hurricanes Florence and Michael and Winter Storm Diego.

In its Application DEC proposed to consolidate its Storm Cost Petition with the rate case and to recover its Storm Costs through a revision to its base rates. In the testimony of Company witness De May, however, the Company linked its Storm Costs recovery request to the passage of Senate Bill 559, An Act to Permit Financing for Certain Storm Recovery Costs (SB 559), and indicated that if that pending legislation were enacted by the General Assembly the Company would seek recovery of its Storm Costs through a securitization filing instead of in revised base rates.

In his direct testimony Company witness Jackson detailed DEC's general storm response and recovery systems and procedures. Tr. vol. 11, 754-69. He described how DEC plans for, prepares to respond, and ultimately does respond to major storm events impacting its system. Witness Jackson also testified to the details of the three storms impacting DEC's system in 2018, recovery for which was being sought in this proceeding. Those three storms were: Hurricanes Florence, Hurricane Michael, and Winter Storm Diego. Tr. vol. 11, 769-77. Company witness Jackson described the Company's extensive responses to those storms and the capital investments and O&M expense associated with those responses. *Id.* at 777-91. Witness Jackson testified that he believed DEC's response to the storms, including its restoration efforts, was reasonable and prudent and resulted in the restoration of power to DEC's impacted customers as quickly and safely as was reasonably possible. *Id.*

In her direct testimony DEC witness Jane McManeus proposed that the Commission allow DEC to recover the incremental cost in excess of normal storm expenses, including a return on the unrecovered balance. DEC witness McManeus proposed to begin amortization of the costs when proposed new base rates became effective and to include a return on the deferred balance through the end of the proposed eight-year amortization period.

In its Application DEC's Storm Costs, which were projected through July 31, 2020, totaled approximately $193.4 million, which consisted of approximately $168.4 million in actually incurred or projected storm response O&M costs and approximately $25.0 million in deferred depreciation expense and carrying costs (calculated using DEC's approved weighted average cost of capital) on its actual incurred storm response costs. Witness McManeus' Second Supplemental Direct Testimony and Schedules included updated actual amounts of DEC's Storm Costs totaling $213.1 million, consisting of $169.8 million in actually incurred or projected storm response O&M costs, $18.6 million in capital investments, and $24.7 million in carrying costs (calculated using the Company's approved weighted average cost of capital through July 31, 2020).

The only other witness to offer testimony on storm response and recovery costs in this proceeding was Public Staff witness Boswell. Witness Boswell, in her direct testimony, indicated that the Public Staff had reviewed the Storm Costs sought to be recovered in this proceeding and had concluded that they were prudently incurred. Tr. vol. 17, 259. Witness Boswell also indicated that she had made an accounting adjustment to remove the Storm Costs from the rate relief requested in this docket on the basis of Company witness De May's testimony that if the (then pending) storm cost securitization legislation was enacted DEC would seek to recover its Storm Costs through the alternative securitization mechanism provided by that legislation. *Id*. at 258. Finally, Public Staff witness Boswell adjusted DEC's revenue request to allow for a ten-year normalization of future storm costs that are not sufficient to support a separate securitization filing. *Id*. at 259.

In rebuttal testimony Company witness De May testified that SB 559 had been passed by the General Assembly and that the Company looked forward to pursuing recovery of its Storm Costs through a separate securitization filing, but that the Company believed that a determination of the reasonableness and prudence of its Storm Costs should be preserved in the general rate case for determination by the Commission. Tr. vol. 11, 875-76.

On March 25, 2020, DEC and the Public Staff filed the First Partial Stipulation in this proceeding in which these parties reached agreement as to the proper resolution of several pending issues in the general rate case proceeding, including the treatment of Storm Costs. In the First Partial Stipulation DEC accepted the "Public Staff's adjustments to remove the capital investments and O&M costs associated with the Storms and to reflect a 10-year normalized level of storm expense for storms that would not otherwise be large enough for the Company to securitize." First Partial Stipulation, § III.1. As agreed in the First Partial Stipulation, DEC removed the Storm Costs and associated capital investments from the rate case to pursue securitization.

DEC and the Public Staff also agreed to a presumptive filing schedule and filing parameters for DEC's securitization filing for its Storm Costs and reserved their respective rights if such filing was not made by the Company. *Id.* at 7-9. Finally, the parties agreed that a storm cost recovery rider should be established for DEC with an initial balance of $0. *Id.* at 9. More specifically regarding the filing schedule, DEC agreed to file a petition for a financing order pursuant to N.C.G.S. § 62-172 no later than 120 days from the issuance of an order by the Commission in this rate case in which the Commission makes findings and conclusions regarding the Storm Costs and the First Partial Stipulation, unless a party in the rate case appeals the Commission's order as it relates to the Storm Costs or the provisions of the First Partial Stipulation related to the Storm Costs and securitization. If an appeal is filed, the 120-day limit shall be suspended until the Commission's decision is affirmed, or if not affirmed, until the issuance of a Commission Order on remand following the decision on the appeal, unless the Company chooses before that time to pursue recovery as further described below, in which case the original 120-day limit shall be deemed to have applied. Should DEC fail to file a petition within the time period specified in this paragraph, DEC and the Public Staff agreed that in any subsequent ratemaking proceeding held to provide for recovery of the Storm Costs, the parties reserve the right to assert their respective positions regarding the appropriate ratemaking treatment of the Storm Costs. *Id.,* § III.2.

DEC filed its Storm Costs securitization financing petition with the Commission on October 26, 2020, in Docket No. E-7, Sub 1243.

With regard to the parameters that would be followed in the securitization proceeding, DEC and the Public Staff agreed that to demonstrate quantifiable benefits to customers in accordance with N.C.G.S. § 62-172(b)(1)g., DEC must show that the net present value of the costs to customers using securitization is less than the net present value of the costs that would result under traditional storm cost recovery. For purposes of settlement for the Storm Costs only, the stipulating parties agreed that when conducting this comparison in the subsequent securitization docket for the Storms, the following assumptions shall be made:

(1) For traditional storm cost recovery, 12 months of amortization for each Storm was expensed prior to the new rates going into effect;
(2) For traditional storm cost recovery, no capital costs incurred due to the Storms during the 12-month period were included in the deferred balance;
(3) For traditional storm cost recovery, no carrying charges were accrued on the deferred balance during the 12-month period following the date(s) of the Storm(s);
(4) For traditional cost recovery, the amortization period for the Storms is a minimum of ten years; and
(5) For securitization, the imposition of the Storm recovery charge begins nine months after the new rates go into effect.

Id., § III.3.

DEC and the Public Staff further agreed that pursuant to N.C.G.S. § 62-172, the amortization of securitized Storm Costs shall not begin until the date the storm recovery bonds are issued. *Id.*, § III.4.

DEC and the Public Staff also agreed that a storm cost recovery rider initially set at $0 should be established in this rate case, and if DEC does not file a petition for a financing order or is unable to recover the Storm Costs through N.C.G.S. § 62-172, the Company may request recovery of the Storm Costs from the Commission by filing a petition requesting an adjustment to this rider. In such case, DEC and the Public Staff reserve the right to argue their respective positions regarding the appropriate ratemaking treatment for recovering the Storm Costs. *Id.*, § III.5.

Finally, DEC and the Public Staff agreed to file a joint petition for rulemaking to establish the standards and procedures that will govern future financing petitions under N.C.G.S. § 62-172 upon the issuance of storm recovery bonds for the Storm Costs. *Id.* at Section III.6. No other party provided evidence on DEC's Storm Costs or its storm response and recovery procedures, and no party contested the conclusions of the Company and the Public Staff that DEC's Storm Costs were reasonable and prudent.

Discussion and Conclusions

Based upon the evidence and the record, the Commission finds and concludes that DEC's actual costs incurred to respond to and recover from Hurricanes Florence and Michael and Winter Storm Diego, totaling $213.1 million, and consisting of approximately $169.8 million in actually incurred or projected storm response O&M costs, capital investments of $18.6 million (including deferred depreciation expense), and $24.7 million in carrying costs (calculated using the Company's approved weighted average cost of capital, through July 31, 2020) were reasonable and prudent, to the extent such costs represent actual amounts as of May 31, 2020. Any estimated costs as of that date or incurred afterward should remain subject to review in the financing proceeding conducted pursuant to SB 559, or to consideration for recovery in a future general rate case proceeding, pursuant to the provisions of N.C.G.S.§ 62-172(a)(14)(c). Any updates to the deferred Storm Costs projections for storm recovery activities still underway should be provided at the time of the securitization filing.

The Commission also accepts DEC's removal of its Storm Costs from the revenue requirement requested in this proceeding in favor of a separate securitization filing, and the Commission further accepts the ten-year normalized adjustment to DEC's revenue requirement to account for anticipated storm expenses that are not large enough in size to securitize.

The Commission gives substantial weight to the Storm Cost provisions of the First Partial Stipulation and concludes that it is appropriate and consistent with SB 559 that DEC continue to defer its Storm Costs intended to be securitized in a regulatory asset account until the date on which the storm recovery bonds are issued pursuant to an approved financing order in accordance with N.C.G.S. § 62-172, or alternative cost recovery is sought by the Company. The amounts recorded in the regulatory asset account will be subject to review by intervening parties and the Commission in the securitization proceeding. Further, it is appropriate and consistent with the statute that DEC continue to accrue and record carrying costs, at the Company's approved weighted average cost of capital, on the deferred balances in its Storm Costs recovery deferred account pending recovery through securitization, subject to review by intervening parties and the Commission in the securitization proceeding.

Consistent with DEC's and the Public Staff's agreement in their First Partial Stipulation, the Commission does not object to the Company's using the assumptions the Public Staff and DEC agreed to in the First Partial Stipulation to demonstrate quantifiable benefits to customers, in accordance with N.C.G.S. § 62-172(b)(1)g. However, the Commission makes no determination in this proceeding as to whether the assumptions and conditions agreed to by the stipulating parties are appropriate for use in the calculation of the quantifiable benefits to customers. Rather, the Commission concludes that the appropriateness of the provisions of the First Partial Stipulation regarding the assumptions and methods to be utilized in the demonstration of quantifiable benefits to customers in accordance with N.C.G.S. § 62-172(b)(1)g are matters to be decided in connection with the Company's joint petition, along with DEP, for financing orders in the securitization docket. In addition, the Commission accepts the stipulation provision on the stipulating parties' agreement to file a joint petition for rulemaking to establish the standards and procedures that will govern future securitization petitions under N.C.G.S. § 62-172.

The Commission also finds appropriate and reasonable the provisions of the First Partial Stipulation regarding the filing procedure for the securitization proceeding, the agreed-to delay in beginning the amortization of securitized costs, the provisions for establishing a provisional deferral of the storm costs pending the outcome in the securitization docket, and the commitment to pursue a rulemaking proceeding for future securitizations. The Commission concludes that these provisions serve to protect the interests of the Company and its ratepayers.

Finally, the Commission accepts the provision of the First Partial Stipulation to adopt a contingent storm cost recovery rider as a place holder in the event that securitization of the costs is denied and recognizes that DEC and the Public Staff have reserved their rights to argue their respective positions regarding the appropriate ratemaking treatment for the Storm Costs.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 62–63

Adjustments to Plant in Service

The evidence supporting these findings of fact is found in the verified Application and Form E-1, the testimony and exhibits of Public Staff witness Metz and Boswell, and the entire record in this proceeding.

Summary of the Evidence

Public staff witness Metz recommended that the capital costs associated with the Lincoln County Combustion Turbine 17 (LCCT 17) project be removed from rate base. He further recommended that the capital costs associated with Project Focal Point 12 also be removed from rate base. Witness Metz testified that he was recommending the removal of the LCCT 17 project due to language that was included in the Commission's order approving the LCCT 17 CPCN in Docket No. E-7, Sub 1134 issued on December 7, 2017. He stated that the order granted the Lincoln County CT CPCN on the condition that "DEC will not seek cost recovery before the later of December 1, 2024, or the date by which DEC has taken care, custody and control and placed the unit into commercial operation."

Witness Metz noted that this language was clear — DEC was not to include any costs of the LCCT 17 and associated transmission lines in rates until after December 1, 2024. Witness Metz indicated that based on his review DEC had included certain costs associated with the support and operation of LCCT 17 in rate base in the May 2020 Updates. Public Staff witness Metz further stated that it was his understanding that DEC agreed with the removal of these costs. Witness Metz recommended a total of approximately $14.3 million (system basis) be removed from rate base. Further, Witness Metz testified that once the project meets the conditions set forth in the Commission's Sub 1134 order, the project cost(s) may be properly included in any general rate case request for cost recovery at that time. He took no stance on reasonableness or prudence of these costs.

With regard to the Focal Point Project (Focal Point), witness Metz testified that Focal Point is a corporate-wide initiative to replace and upgrade older monitoring and recording equipment (e.g., cameras) with modern, state of the art equipment. He noted that once this upgrade is complete, it is intended to be an overall upgrade to Duke Energy's security system. Witness Metz testified that his reasoning for recommending removal of these costs was due to the fact that these costs were for equipment that is not fully installed and operational. Witness Metz recommended a total system cost adjustment of approximately $3.7 million. He stated that these should be sought for cost recovery once installed. He further noted that DEC agreed to not request cost recovery in this proceeding.

Witness Metz testified that both of his adjustments had been incorporated into the schedules and exhibits presented by Public Staff witness Boswell.

Discussion and Conclusions

In light of the evidence presented in this proceeding, the Commission finds and concludes that the adjustments to remove the costs associated with the LCCT 17 and Focal Point projects are appropriate and just. Both parties agree the costs related to both the LCCT 17 and Focal Point projects should be removed from rate base in the current proceeding. The Commission agrees that the instant proceeding is not the proper place to seek recovery of these costs at this time. The Commission agrees that its language in its order in Docket No. E-7, Sub 1134 is clear. DEC is not to seek recovery of costs related to the LCCT 17 and associated transmission lines until after December 1, 2024. With regard to the Focal Point costs, the Commission does not consider these costs ripe for cost recovery because they are for equipment that is not installed or operational. As such, the Commission finds that these costs should be removed from rate base at this time.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 64

Prepaid Advantage Program

The evidence supporting this finding of fact is found in the verified Application and Form E-1; the Public Staff Second Partial Stipulation; the testimony and exhibits of DEC witness Barnes, Public Staff witness Floyd, and NCJC et al. witness Howat; and the entire record in this proceeding.

Summary of the Evidence

On August 2, 2019, DEC filed a Petition for Approval of Prepaid Advantage Program in Docket No. E-7, Sub 1213, requesting to offer customers the billing option to prepay for service, thereby avoiding the need for a deposit, reconnection fees, and late fees. DEC further requested that the Commission waive certain Commission Rules related to the monthly bill format, payments, and disconnection, specifically Rules R8-8, R8-20(b), (c), and (d), R8-44(4)(d), R12-8, R12-9(b), (c), and (d), and R12-11(a), (b), (f), (g), (h), (i), (l), (m), (n), and (p). The Public Staff presented the Prepaid Advantage Program for approval at the Commission's Regular Staff Conference on November 12, 2019. On November 20, 2019, the Commission issued an order consolidating DEC's request with DEC's general rate case application.

Company witness Barnes testified in support of the Prepaid Advantage Program. Witness Barnes explained that by utilizing the benefits of smart meters, the program will offer customers the voluntary billing option to prepay for electric service in advance of usage, thereby providing various customer benefits, including avoiding the need for a deposit, reconnect fees, or late fees. Tr. vol. 11, 719. She further explained that DEC introduced a similar prepaid advantage program in its South Carolina service territory in 2015 that has successfully delivered increased customer satisfaction and energy savings — on average, participating South Carolina customers experienced an 8.5% reduction in their energy usage. *Id.* Witness Barnes could not definitively state whether the energy usage reductions were a result of the South Carolina program's design as a whole or as individual features of the program. Tr. vol. 13, 161-62.

Public Staff witness Floyd summarized the Prepaid Advantage Program as follows: new or existing customers with smart meters may elect to participate in this program are enrolled in the Equal Payment Plan, have an active deferred payment arrangement exceeding $500, or are identified as a medical alert customer pursuant to Commission Rule R12-11(q). Customers will have the ability to review daily usage information through a secure web portal accessible by a computer or smartphone with internet, as well as receive account notifications via phone, email, or text message. Tr. vol. 18, 289. Witness Floyd stated that to enroll, participants will be required to make an initial payment of at least $40. *Id.* at 290. Participants with an outstanding balance when enrolled in the Prepaid Advantage Program will have 25% of any payments credited toward the unpaid balance until that balance is satisfied. After enrollment, participants can increase their account balances as frequently as they desired. *Id.*

Witness Floyd explained that the Prepaid Advantage Program is designed to provide participants with frequent notices regarding their account balance, including five, three, and one-day notifications prior to their account reaching a zero balance. *Id.* As such, customers will be required to provide DEC with a notification channel preference such as text, email, or phone by which DEC would communicate with them regarding their account balances and usage. Once an account reaches a zero balance, the customer will have until the next business day to make a payment before the customer's service is remotely disconnected. *Id.* To have service reconnected, the customer must pay any outstanding balance and make an additional payment towards future service. *Id.* Service may be reconnected remotely (within approximately 15 minutes) following payment after a disconnection. *Id.* at 290-91. Payments can be made online through the program portal, over the phone, or in person. *Id.* at 291). Billing rates for service will be the same as those for traditional post pay service (Schedule RS). However, rates for basic customer charges, taxes, and other per account or flat charges will be applied to the prepaid account on a daily pro-rata basis. *Id.*

Public Staff witness Floyd also noted that New River Light and Power Company presented to the Commission a similar prepaid service program in Docket No. E-34, Sub 49 — in terms of process, mechanics, and waiver of Commission rules — that the Commission approved on June 25, 2019, and that 20 of 26 North Carolina-based electric membership cooperatives provide some form of prepayment option for customers. *Id.* at 293. He stated that he believes that DEC customers would be interested in the program. Witness Floyd testified that the Prepaid Advantage Program should be approved with certain conditions and reporting requirements. *Id.* at 299. He also recommended that the following conditions for the requested waiver of Commission rules apply:

1. No disconnection before 3:00 p.m. to allow affected customers as much time as possible to make the necessary payments;
2. That the Company makes all reasonable efforts to have on file a third-party designee, selected by the customer, who will receive any notice of termination in addition to the customer; and
3. That the limited waiver to Rule R12-11(m)(2) would expire on June 30, 2021, unless otherwise extended by the Commission.

Id. Witness Floyd further recommended that DEC should confirm the ability of Prepaid Advantage Program participants to receive communications from the Company upon enrollment and noted that customers who were not able to receive notifications from the Prepaid Advantage Program should be ineligible for the program. *Id.* at 300.

Finally, witness Floyd recommended that DEC submit quarterly reports on the performance of the Prepaid Advantage Program by calendar month. *Id.* at 301. He stated that the Public Staff would work with the Company to refine the information needed, but believed such reporting should include at least the following items: (1) number of participants enrolled on the last day of each month, (2) number of participants that withdraw from the Prepaid Advantage Program and return to standard arrears billing, (3) average number of transactions observed per participant, distinguished by the method of payment used, (4) distribution of payment amounts (from least to most) and the average amount added to the account per transaction, (5) distribution of disconnections per participant, (6) number of participants with more than one disconnection in a 90-day period, (7) total number of disconnections, (8) average customer balance at time of disconnection, and (9) average time from disconnection to reconnection. *Id.* at 301-02.

Company witness Barnes testified that DEC agreed to waive the transaction fee for any transaction involving credit and debit cards or electronic checks for the program's participants and also agreed to each of the Public Staff's recommended conditions and reporting requirements. Tr. vol. 11, 719-21.

NCJC et al. witness Howat expressed his concerns with utility prepaid programs, in general, and recommended that DEC's Prepaid Advantage Program be denied. Tr. vol. 17, 600. He testified that the Prepaid Advantage Program is not an affordability program that enhances low-income energy security and observed that prepaid programs are typically composed of a variety of features, some of which are helpful for customers such as provision of timely information regarding energy usage and expenditures. *Id.* at 589, 600. He also testified that lower income households tend to enroll more frequently in prepaid services because there is often no deposit required and those enrolled in prepaid services are disconnected from electricity service more frequently than those customers enrolled a traditional billing program. *Id.* at 590.

Witness Howat also outlined the important consumer protections removed by the Prepaid Advantage Program which he believed would bring considerable risk for customers' energy security, including secure, reliable notification prior to disconnection of service, limitations on disconnection under certain circumstances, the right to dispute a bill, and special protections for the elderly and disabled. Tr. vol. 17, 589-91. Witness Howat was particularly concerned with the period of time between when a customer's billing credits expire and when their utility service is shut off. Tr. vol. 10, 145. Witness Howat also referenced, and agreed with the criticisms contained in, the letter from Mr. Alfred Ripley and others on behalf of the NCJC and other organizations filed with the Commission in Docket No. E-7, Sub 1213. Tr. vol. 17, 592; NCJC et al. Ex. JH-7. The NCJC's letter expressed particular concern with the Company's proposal to allow rapid remote disconnections while at the same time waiving several Commission rules providing protections for disconnections. *Id.*

Finally, witness Howat pointed out that the customer benefits gained from prepaid service are not exclusive to the prepaid program but flow from various features of the programs. Tr. vol. 17, 591; tr. vol. 10, 143. Witness Howat also noted that the Company's customers already have the option to pay their electricity bills in advance of receiving their monthly bill and instead supported additional tools to augment this ability. Tr. vol. 10, 144; tr. vol. 17, 591.

Company witness Barnes disagreed with witness Howat's testimony. She testified that the Prepaid Advantage Program was voluntary to any customer who wants an alternative billing and payment arrangement, not limited to low-income customers, but rather held advantages for some low- or fixed-income customers. Tr. vol. 11, 723. Witness Barnes testified that many of the Company's South Carolina prepaid program's low- or fixed-income participants reported benefitting from this payment flexibility. *Id.* Witness Barnes instead agreed with Public Staff witness Floyd that the Prepaid Advantage Program maintains many customer protections and appropriately balances those with the many benefits to participating customers, as well as the need to have appropriate disconnection procedures to protect all customers. *Id.* at 724.

Public Staff witness Floyd also addressed the issues raised in Mr. Ripley's letter and explained that the Public Staff considers the disconnection procedure proposed by the Company for prepaid accounts that reach zero balances to be reasonable. Tr. vol. 18, 296. He highlighted that a customer would receive periodic notices through the communication channel of her choice prior to an account reaching a zero balance and that the actual disconnection would not occur until the next business day, and only under fair weather conditions. Witness Floyd explained that extreme weather conditions and holidays would result in the postponement of disconnection, likely until the next fair-weather business day. *Id.*

Witness Floyd further testified that this short time frame needs to be as small as possible to reduce the amount of energy sales that go uncompensated. *Id.* Otherwise, he explained, the Prepaid Advantage Program would run the risk of increasing lost sales revenues that add to the Company's uncollectible expenses. As such, witness Floyd believes that the process of disconnection only on fair weather business days provides ample protections for those who voluntarily participate in the Prepaid Advantage Program. *Id.* at 296-97.

Witness Floyd also disputed Mr. Ripley's concern that the Prepaid Advantage Program lacked certain attributes recommended by a National Association of State Utility Consumer Advocates (NASUCA) resolution. Tr. vol. 18, 297-98. To the contrary, he explained that many of those attributes are incorporated into the design and implementation of DEC's Prepaid Advantage Program, including that: (1) a grace period exists between a zero balance and disconnection, (2) certain customer segments are ineligible due to medical conditions, (3) the program is voluntary, (4) participants avoid the need for security deposits, (5) participants can increase their account balances at any time, (6) participants can return to postpaid service at any time, subject to the requirements of a security deposit and other costs associated with postpaid accounts, and (7) prepayments are immediately posted to customer's account. *Id.*

Finally, as part of the Second Partial Stipulation, DEC and the Public Staff agreed that the Prepaid Advantage Program should be approved, subject to the conditions in the Commission's November 15, 2019 order in Docket No. E-7, Sub 1210. Second Partial Stipulation, § IV.F.

Discussion and Conclusions

After careful consideration, the Commission agrees with the Company and the Public Staff that the Prepaid Advantage Program will provide customers who choose to enroll with greater flexibility and control over their electric usage and payments. By waiving the deposit and other fee requirements, the Company has increased the benefits to participating customers, especially low- or fixed-income customers. The Commission notes that the program is completely voluntary, but nevertheless appreciates and recognizes the concerns raised by NCJC et al. The Commission gives substantial weight to the testimony of the Public Staff in this regard and thus adopts the safeguards proposed by witness Floyd, namely that: (1) there shall be no disconnection before 3:00 p.m., (2) the Company shall make all reasonable efforts to have on file a third party designee, selected by the customer, who will receive any notice of termination in addition to the customer, and (3) DEC shall confirm the ability of Prepaid Advantage Program participants to receive communications from the Company upon enrollment. Additionally, the Commission gives substantial weight to and thus adopts the Public Staff's recommendations regarding reporting requirements, which the Company has accepted. Accordingly, the Commission concludes that the provision of the Second Partial Stipulation agreeing that the Prepaid Advantage Program should be approved is reasonable and in the public interest. The Prepaid Advantage Program is therefore approved subject to the conditions as set forth herein and as accepted in the Second Partial Stipulation. The Commission also approves DEC's requested waiver of the requirements of Commission Rules R8-8, R8-20 (b), (c), and (d); R8-44(4)(d); R12-8; R12-9(b), (c), and (d); and R12-11(a), (b), (f), (g), (h), (i), (l), (m), (n), and (p), only with respect to service rendered under the Prepaid Advantage Program.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 65–67

AMI and Green Button Connect

The evidence supporting these findings of fact is found in the verified Application and Form E-1; the Public Staff Second Partial Stipulation; the testimony and exhibits of DEC witnesses Schneider, Pirro, and Hatcher, Public Staff witness Floyd, and Commercial Group witness Chriss; and the entire record in this proceeding.

Summary of the Evidence

DEC witness Schneider testified that DEC installed approximately one million AMI meters from July 1, 2018, through June 30, 2019, bringing DEC's total installed AMI meters to two million, with deployment of AMI being almost complete in North Carolina. He testified that DEC expended $118.4 million on AMI meters in North Carolina and South Carolina from January 1, 2018, through June 2019, and projects that it will spend $9.1 million from July 1, 2019, through December 31, 2019, the project end date. In addition, he testified that DEC enrolled 1.627 customers in its opt-out program from October 2018 through June 2019. Tr. vol. 13, 139-40.

Witness Schneider further testified to the benefits of AMI, including customer access to more usage information, speedier storm outage detection and restoration, more flexibility in customer billing dates, and new time-of-use rate designs. *Id.* at 140-44.

DEC witness Pirro testified that DEC reviewed its costs of Rider MRM, the AMI meter opt-out tariff approved by the Commission in 2018 in Docket No. E-7, Sub 1115. He stated that the updated costs could justify an increase in the one-time setup fee from its present level of $150 to $230, and the monthly fee from $11.75 to $14.05. However, DEC is not requesting an increase in the fees because Rider MRM has been in effect less than one year and the Company believes adjusting the fees associated with opt-out is premature. Tr. vol. 12, 255.

Public Staff witness Floyd testified that the Public Staff agrees with DEC's decision not to increase the AMI setup fee and monthly fee at this time. In addition, he stated that DEC has enrolled 884 residential and small general service customers in Rider MRM, with 663 having been found eligible for waiver of the fees. He stated that the Public Staff believes that Rider MRM costs that are not recovered from customers opting out of AMI meters should be recovered from all DEC customers. Tr. vol. 18, 279-81.

Witness Floyd further testified that DEC's customers will see a benefit from AMI by a reduction in connection and reconnection fees. He stated that DEC proposes reducing its connection fee from $24.18 to $10.51, and its reconnection fee from $27.13 to $9.25. He further stated that these changes are supported by the Company's cost calculations. *Id.*

In Section IV.I of the Second Partial Stipulation, DEC and the Public Staff agreed that the Rider MRM costs that are not recovered from opt-out customers should be recovered from all DEC customers.

Commercial Group witness Chriss recommended in his direct testimony that the Commission require DEC to include Green Button "Connect My Data" (Green Button) as part of the Company's means of providing access to electric usage data. Tr. vol. 16, 77-78. In the Commercial Group Stipulation, the parties agreed in Paragraph No. 5 that the Company met with Commercial Group and adequately addressed its concerns regarding data access and Green Button.

During the hearing, in response to questions by the AGO and on redirect, Company witness Hatcher testified that the benefits of AMI include enhanced customer information and control over their consumption of electricity, the opportunity to pick their payment due date and to receive usage alerts, and benefits related to storm response. Tr. vol. 11, 956-57, 1016-17.

In its post-hearing brief the AGO contended that DEC plans to integrate AMI meters with its Customer Connect billing platform using My Duke Data Download, characterized by the AGO as a nonstandard, outdated technology. Tr. vol. 11, 968; AGO Hatcher Cross-Examination Ex. 2. According to the AGO, DEC modeled its technology on older technology called Green Button Download that has more limited capabilities than the standard technology now available. The AGO asserted that if DEC had incorporated the advanced and readily available Green Button, or a similar technology, customers could conveniently access their data and authorize automated access by third parties *Id.* at 968, 973. As a result, the AGO requested that DEC be required to file revised Customer Connect plans that incorporate Green Button or another similarly advanced standard technology, or if that is not possible, the AGO requested that DEC be required to propose an alternative plan.

Discussion and Conclusions

The testimony of DEC's witnesses Schneider and Pirro, as well as Public Staff witness Floyd, provides substantial evidence that DEC has continued its deployment of

AMI meters since the Commission's 2018 DEC Rate Order in a prudent manner and that the costs of such continued deployment are reasonable. In addition, the testimony and the Second Partial Stipulation provide substantial evidence that the Rider MRM costs that are not recovered from opt-out customers should be recovered from all DEC customers.

With respect to the AGO's contention that DEC should be ordered to implement Green Button, the Commission is not persuaded. The Commission has an ongoing investigation and rulemaking in Docket No. E-100, Sub 161 on customer and third-party access to electric usage data. Numerous parties, including the AGO, have filed comments and proposed rules, some of which include guidelines for the possible role of Green Button.

Based on the foregoing, the Commission concludes that DEC should be allowed to recover its costs of AMI deployment, and that the Rider MRM costs that are not recovered from opt-out customers should be recovered from all DEC customers. In addition, the Commission concludes that it should not require DEC to incorporate Green Button into its Customer Connect billing system at this time.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 68–71

Service Regulations, Vegetation Management, and Quality of Service

The evidence supporting these findings of fact is found in the verified Application and Form E-1; the Public Staff Second Partial Stipulation; the testimony and exhibits of DEC witnesses Pirro, Oliver, McManeus, and Hatcher, Public Staff witnesses Floyd, David Williamson, Tommy Williamson, and Boswell; and the entire record in this proceeding.

Summary of the Evidence

Service Regulations

In his direct testimony and his Exhibit 1, Company witness Pirro identified DEC's proposed changes to several charges contained in its service regulations that DEC proposed to be effective for service rendered on and after October 30, 2019. According to witness Pirro, the changes are intended to better reflect current cost studies along with the benefits of Smart Meter implementation. Tr. vol. 12, 236, 256; Pirro Ex. 1, DEC's North Carolina Retail Electric Rate Schedules and Service Regulations. The proposed changes include decreases in: (1) the Connect Charge from $24.18 to $10.51, and (2) the Reconnect Charge to restore service during normal business hours from $27.13 to $9.25 and during all other hours from $27.13 to $10.58. *Id.* at 256. Other proposed changes include corrections to typographical errors and a few other minor revisions and clarifications described in DEC witness Pirro's direct testimony. *Id.* at 256-57.

Public Staff witness Floyd testified that he reviewed the Company's proposed changes to its connection and reconnection fees and that he believes them to be reasonable. Tr. vol. 18, 281. No party testified in opposition to the Company's proposed changes to its Service Regulations or cross-examined the Company's witnesses on this issue at the hearing.

Vegetation Management

In his prefiled direct testimony, DEC witness Oliver testified that vegetation management is a critical component of the Company's customer delivery operations. He stated that the Company uses a combination of a reliability-based and a time-based prioritization model to drive its vegetation management program. He indicated that the Company's need for a funding increase adjustment for the program is two-fold. First, contractor labor costs have increased from the levels upon which the Company's current annual vegetation management costs are calculated. Tr. vol. 11, 609. Second, the number of annual miles targeted for vegetation management has also increased due to Hurricanes Florence and Michael and Winter Storm Diego. *Id.* In DEC witness McManeus' direct testimony and exhibits, she calculated the distribution system vegetation management cost increase to be $5,490,000, the amount found reasonable in Sub 1146. McManeus Direct Ex. 1, Item NC 2701, line 2.

In their direct testimony, Public Staff witnesses Tommy Williamson and David Williamson testified that they investigated the Company's vegetation management activities and found that the Company has eliminated 6,859 miles of the 13,467 miles of vegetation management backlog identified in Docket No. E-7, Sub 1146. Tr. vol. 17, 295-97. They also testified that the Company is on track to eliminate the remaining vegetation management backlog by 2022. *Id.* at 297. Nevertheless, they testified that Public Staff recommends that the Commission continue to require the Company to file semi-annual VM Plan reports as outlined in the Commission's Orders in Docket Nos. E-7, Subs 1146 and 1182, so that Public Staff may monitor the reports and inform the Commission of any issues or if it appears the Company is no longer on track to eliminate the backlog. They further agreed that the Company's target annual miles have increased, and that contract labor charges have also increased. *Id.* at 298. As a result, the Public Staff agreed that the 3% increase cited by the Company in contract labor charges is reasonable. *Id.*

The Public Staff witnesses further testified, however, that their analysis uncovered an error in the Company's calculation of vegetation management costs per mile and corrected that calculation before reporting the results of their investigation to Public Staff witness Boswell. *Id.* at 299. According to them, the Company utilized the wrong dollar amount per mile trimmed for the test period. Witness Boswell thus appropriately made an adjustment of $205,000 to the Company's proposed annual vegetation management cost increase. *Id.*; tr. vol. 17, 254-55; Boswell Ex. 1, Schedule 3-1(d).

DEC did not dispute the Public Staff's adjustment, and no other party presented evidence on DEC's annual vegetation management costs or cross-examined the Company's witnesses on this issue.

Service quality

DEC witness Hatcher provided testimony relating to the Company's service quality and ways in which the Company is working to enhance the customer experience. Tr. vol. 11, 898-99. Witness Hatcher noted that customer satisfaction (CSAT) is a key focus area for DEC. *Id.* at 898, 907. He explained that using data and analytics the Company is executing a long-term, customer-focused strategy designed to deliver greater value to its customers. *Id.* at 900. The Company's CSAT program includes both national benchmarking studies and proprietary transaction and relationship CSAT studies. *Id.* at 907-08. Witness Hatcher explained that the Company analyzes the results from these studies in vigorous monthly data review sessions, with findings driving improvements to processes, technology and behaviors — all to continuously improve the customer experience. *Id.* Specifically, he explained that DEC measures overall customer satisfaction and perceptions about the Company via its proprietary relationship survey, the Customer Experience Monitor Survey (CX Monitor Survey), which randomly measures customer loyalty and ongoing perceptions of several customer classes. *Id.* at 908. The CX Monitor Survey data is used to calculate the Company's Net Promoter Score (NPS), a top metric used by companies across industries to measure customer advocacy. *Id.* at 899-900. He indicated that since 2019 the Company has seen a significant increase in its NPS, with some of the Company's highest NPS scores occurring between the months of September and December of 2018, overlapping times of major storms. *Id.* at 909.

DEC witness Hatcher also explained that in addition to its relationship study, DEC utilizes Fastrack 2.0, the Company's proprietary, post-transaction measurement program, to measure overall customer satisfaction with the Company's operational performance. Tr. vol. 11, 909-10. Fastrack 2.0 was designed to complement the CX Monitor survey and provide insight into experiences that matter to DEC's customers and near real time feedback to front line, customer-facing employees. *Id.* at 914. Witness Hatcher explained that analysis of these ratings helps identify specific service strengths and opportunities that drive overall satisfaction and provides guidance for the implementation of process and performance improvement efforts. *Id.* Through 2018, roughly 80% of DEC residential customers expressed high levels of satisfaction with key service interactions: Start/Transfer Service, Outage/Restoration, and Street Light Repair. *Id.* at 910. Witness Hatcher stated that the Company has also implemented "Reflect," a post-contact survey that gathers customers' immediate feedback after contacting Duke Energy by web, text, call to automated system, or live agent. *Id.*

Witness Hatcher further explained that the Company is working hard across its business to further improve the customer experience by making strategic, value-based investments for the benefit of customers. *Id.* at 916. Key examples include enhancements to the Company's integrated voice response (IVR) system and the deployment of Customer Connect. *Id.* at 916-19. Finally, witness Hatcher identified additional programs to improve customer service, explaining that the Company seeks approval to eliminate convenience fees for credit and debit card payments made by residential customers, as well as to extend the bill payment due date for nonresidential customers from 15 days to 25 days. *Id.* at 920-24, 926-27.

Public Staff witnesses David Williamson and Tommy Williamson also jointly testified regarding DEC's quality of service. Tr. vol. 17, 292-94. In evaluating the Company's overall quality of service, they reviewed the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) reliability scores filed by DEC with the Commission in Docket No. E-100, Sub 138A; informal complaints and inquiries from DEC customers received by the Public Staff's Consumer Services Division; the consumer statements of position filed in Docket No. E-7, Sub 1214CS; and the Public Staff's own interactions with DEC and its customers. *Id.* They noted that for the period 2010 through 2019, Company reports show the SAIDI and SAIFI indices are worsening. *Id.* at 293. However, they noted there has been some realized improvement for calendar year 2019, primarily from a reduction in vegetation and equipment failure related outages, compared to the previous year. They concluded that the quality of service provided by DEC to its North Carolina retail customers is adequate at this time. *Id.*

DEC and the Public Staff further agreed in Section IV.M. of the Second Partial Stipulation that the Company's quality of service is good. No party offered any evidence contradicting this assessment.

Discussion and Conclusions

The Commission concludes that the Company's proposed amendments to its Service Regulations are reasonable and appropriate and should be approved.

The Commission also concludes that DEC's vegetation management performance is reasonable and that it is appropriate to adopt and incorporate into the Company's costs the adjustments to annual vegetation management costs per mile and annual vegetation management expense that Public Staff witnesses Boswell and Williamsons applied in their testimony to the Company's proposed annual costs. The Company shall continue to file semi-annual vegetation management reports as directed in Docket Nos. E-7, Subs 1146 and 1182, and the Public Staff shall monitor the reports and inform the Commission if there are any issues or if it appears the Company is no longer on track to eliminate the 2017 vegetation management backlog.

Finally, the Commission finds and concludes that the overall quality of electric service provided by DEC is good.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 72

Accounting for Deferred Costs

The evidence supporting this finding of fact is found in the verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

In the present case, the Commission is approving DEC's recovery through amortization of a previously deferred portion of DEC's CCR costs. A deferred cost is an exception to the general principle that the Company's current cost-of-service expenses should be recovered as part of the Company's current revenues. As a result, a deferred cost is not the same as the other cost-of-service expenses to be recovered in the Company's non-fuel base rates and, therefore, should be subject to different accounting guidelines.

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

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 73

Just and Reasonable Rates

The evidence supporting this finding of fact is found in the verified Application and Form E-1, the testimony and exhibits of the witnesses, including DEC witnesses De May, Immel, Capps, and Schneider, and the entire record in this proceeding.

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

DEC witness De May testified that the Company is experiencing significant changes throughout many aspects of the electric industry, and that the investments DEC has made and must continue to make are designed to keep pace with evolving customer needs and expectations. Witness De May stated that the Company's investments are capital intensive, and the Company has incurred costs that are not included in its current rates. As one example, he stated that DEC's customers want more information about how they consume energy and more tools that help them manage their consumption. According to witness De May, DEC is responding by investing in a more efficient distribution grid, AMI meters, and cleaner and more efficient generation units. In addition, he stated that DEC is actively working toward achieving a lower carbon future by taking steps to reduce its reliance on coal-fired generation, including investments in generation resources like natural gas and solar. Moreover, witness De May testified that DEC is committed to helping customers who struggle to pay for essential needs like electricity with programs and options to assist them, such as the Share the Warmth program, and DSM and energy efficiency programs. Tr. vol. 11, 857-62. Indeed, as part of the First and Second Partial Stipulations, DEC will make shareholder-funded contributions, in conjunction with the concurrent commitment of DEP, of a combined $3 million per year for two years to the Helping Home Fund, for a total of $6 million. Further, DEC will make an annual $2.5 million shareholder-funded contribution to the Share the Warmth Fund in 2021 and 2022, for a total contribution of $5 million.

Witness De May and other witnesses also described the importance of DEC maintaining a strong financial position in order to facilitate the Company's investments in utility service infrastructure. He stated that the Company's strong financial position and performance benefit customers by reducing DEC's cost of borrowing and cost of attracting equity capital. *Id.* at 863-65. As previously discussed, the Commission does not set rates based on DEC's credit metrics. Rather, the Company's credit ratings and other credit metrics are the responsibility of the Company to manage. Nonetheless, the Commission has considered the evidence on potential credit impacts and given that evidence due weight as a part of the Commission's ratemaking task that requires the Commission to set rates that are fair to DEC and its ratepayers. N.C.G.S. § 62-133. The utility's access to credit at a reasonable cost is important to both DEC and its ratepayers. Both benefit if DEC can obtain credit at the best interest rates reasonably possible. The Commission concludes that the rates set herein achieve the appropriate balance of being credit supportive for DEC and fair to DEC's ratepayers.

In addition, DEC witness Immel testified that since its previous rate case the Company has made capital investments in its fossil, hydroelectric, and solar generating units that enable the Company to continue to provide safe and reliable generation. He gave as an example, investments of approximately $689 million to meet environmental regulations and allow for the continued operation of active coal-fired plants, largely driven by dry bottom ash conversions, wastewater treatment enhancements, and lined retention basin projects. He further testified that DEC converted its coal-fired Cliffside Station and Belews Creek Unit 1 to burn natural gas as well as coal, with Cliffside Unit 5 now capable of burning up to 40% natural gas, Cliffside Unit 6 up to 100%, and Belews Creek Unit 1 up to 50%. He stated that this co-firing capability allows DEC to utilize the most cost-effective fuel at any given time, providing the Company with fuel flexibility for the benefit of customers. Tr. vol. 12, 56-58.

DEC witness Capps testified that since DEC's last rate case in 2017 the Company has invested approximately $440 million in capital investments at its Catawba, McGuire, and Oconee nuclear plants. He stated that the investments were necessary to improve safety, comply with new or revised regulatory requirements, enhance reliability, and to manage aging and obsolescence. He provided details of the capital improvements at the three plants, such as IT infrastructure upgrades in 2019. He stated that these upgrades consisted of installing new backbone fiber networks that build on the existing networks, modernizing each station's IT capabilities and supporting additional automated plant monitoring functions. Moreover, he provided testimony about the improvements made in response to cybersecurity concerns and requirements of the Nuclear Regulatory Commission. He also testified that approximately 33% of the required O&M expenditures for DEC's nuclear fleet were fuel-related, and he described how DEC has worked diligently to control the O&M costs of its nuclear fleet. Tr. vol. 11, 732-39.

Witness Schneider testified to DEC's installation of approximately one million AMI meters from July 1, 2018, through June 30, 2019, at a cost of approximately $127.5 million. In addition, he testified to the customer benefits of AMI, including lower cost O&M due to remote disconnections and reconnections, customer access to more usage information, speedier storm outage detection and restoration, more flexibility in customer billing dates, and new time-of-use rate designs. Tr. vol. 3, 139-44.

These are representative examples of the capital investments that have been made and are planned by DEC in order to continue providing safe, reliable, and efficient electric service to its customers. In this time of COVID-19, with many people working and schooling at home, the importance of safe, reliable, and efficient electric service is heightened beyond its normal level as an essential service.

Based on all of the evidence, the Commission finds and concludes that the rates established herein strike the appropriate balance between the interests of DEC's customers in receiving safe, reliable, and efficient electric service at the lowest possible rates, and the interests of DEC in maintaining the Company's financial strength at a level that enables the Company to obtain sufficient capital. As a result, the Commission concludes that the rates established by this Order are just and reasonable under the requirements of the Act and serve the public interest.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 74

Revenue Requirement

The evidence supporting this finding of fact is found in the verified Application and Form E-1; the Public Staff First and Second Partial Stipulations; the testimony and exhibits of the witnesses, including DEC witness McManeus and Public Staff witness Boswell; and the entire record in this proceeding.

The First and Second Partial Stipulations between the Company and the Public Staff provide for certain accounting adjustments that the Company and the Public Staff have agreed upon and the Commission has approved in this Order. The stipulated issues on revenue requirement effects are detailed in McManeus Supplemental Rebuttal Exhibit 3, Boswell Supplemental and Stipulation Exhibit 1, Schedule 1, and Boswell Second Supplemental and Stipulation Exhibit 1, Schedule 1 (Partial Stipulation Revenue Requirement Exhibits), and Public Staff witness Boswell Second Supplemental and Settlement testimony.

DEC's McManeus Second Settlement Exhibit 2 shows DEC's revised requested increase incorporating the details of the Second Partial Stipulation and the Company's position on the remaining unresolved issues. The resulting proposed base revenue requirement of the Company is an increase of $414,433,000. Boswell Second Supplemental and Stipulation Exhibit 1 reflects the Public Staff's revised recommended change in revenue requirement incorporating the provisions of the Second Partial Stipulation. In addition, it reflects the Public Staff's position on the remaining unresolved issues. The resulting proposed base revenue requirement by the Public Staff is an increase in the base rate revenue requirement of $290,049,000, which includes the settled stipulated positions of the Company and the Public Staff.

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

IT IS, THEREFORE, ORDERED as follows:

1. That the approved base fuel and fuel-related costs factors by customer class, are as follows: 1.6027 cents per kWh for the Residential class, 1.7583 cents per kWh for the General Service/Lighting class, and 1.6652 cents per kWh for the Industrial class;

2. That the Company shall amortize the loss on the sale of its hydro stations over a 20-year period;

3. That DEC shall include a return on the unamortized balance related to the loss on the sale of hydro stations;

4. That DEC shall use a 10% contingency for future "unknowns" in the estimate of future terminal net salvage costs

5. That DEC shall use an interim net salvage percentage of zero for Accounts 342, 343, 344, 345, and 346;

6. That DEC shall use an escalation of terminal net salvage cost and the straight-line method of depreciation in determining escalation as performed in the Decommissioning Study;

7. That DEC shall use its proposed future net salvage for mass property Account 366, Underground Conduit;

8. That DEC shall use an average service life of 15 years for the new AMI meters;

9. That the depreciation rates proposed by DEC in this case are approved, except as specifically modified by this Order.

10. That the depreciation rate for the Allen Units 4 and 5 and Cliffside Unit 5 generating plants shall not be changed, and shall be based upon the remaining life of the plants, as approved in DEC's rate case in Docket No E-7, Sub 1146;

11. That upon actual retirement of each generating unit, Allen Units 4 and 5 and Cliffside Unit 5, the remaining net book value shall be placed in a regulatory asset account to be amortized over an appropriate period to be determined in a future rate case;

12. That DEC's cost of capital investments in its coal fleet to meet environmental regulations to allow for the continued operation of active coal units shall be included for recovery in DEC's rates;

13. That DEC's costs related to the Belews Creek Unit 1 DFO project shall be included for recovery in DEC's rates;

14. That the stipulations of DEC with the Public Staff, CIGFUR, Harris Teeter, Commercial Group, Vote Solar, and jointly with NCSEA and NCJC et al. are accepted and approved in part, as detailed in this Order;

15. That DEC shall recover the balance of its deferred CCR costs reduced by $224 million in the present case and shall cease to accrue financing costs on this amount as of December 31, 2020, consistent with the CCR Settlement; and that DEC shall recover the balance of its deferred CCR costs over a five-year amortization period with reduced financing costs during the amortization period calculated based on (1) DEC's cost of debt set forth in the Second Partial Stipulation, adjusted as appropriate to reflect the deductibility of interest expense, (2) an ROE 150 basis points lower than the 9.60% ROE set forth in the Second Partial Stipulation, and (3) a capital structure of 48% debt and 52% equity set forth in the Second Partial Stipulation;

16. That DEC is authorized to record its February 1, 2020, and future CCR costs in a deferred account until its next general rate case; and that this deferral account will accrue a return at the overall rate of return approved in this Order consistent with the CCR Settlement;

17. That the agreed-upon accounting adjustments outlined in McManeus Supplemental Rebuttal Exhibit 3, McManeus Second Settlement Exhibit 3, Boswell Supplemental and Stipulation Exhibit 1, Schedule 1, and Boswell Second Supplemental and Stipulation Exhibit 1, Schedule 1 shall be, and are hereby, approved;

18. That the Company's revised Lead-Lag Study filed as Speros Supplemental Exhibit 3 shall be, and is hereby, approved for purposes of calculating the cash working capital amounts to be included in the Company's revised rates;

19. That DEC's request for an accounting order for approval to establish a regulatory asset to defer the North Carolina retail portion of incremental O&M expenses associated with the Company's severance program, as modified by the terms of the First Partial Stipulation, shall be, and is hereby, approved;

20. That DEC's request for deferral accounting for GIP expenditures is approved consistent with its Second Partial Stipulation with the Public Staff and subject to the conditions set forth in this Order;

21. That DEC shall work expeditiously with the Public Staff to refine its GIP reporting requirements, as intended under the Second Partial Stipulation, and file the first report for spending during the last half of 2020 by May 1, 2021;

22. That the proposed EDIT Rider, as modified by the terms of the DEC and Public Staff Partial Stipulations, is approved and shall be implemented; and that the protected federal EDIT will be removed from the EDIT Rider and returned to customers through base rates;

23. That the agreement between DEC and the Public Staff as outlined in the Second Partial Stipulation concerning how to address changes in the federal corporate income tax rate or North Carolina state corporate income tax rate, which may occur during the respective amortization periods is hereby approved;

24. That the CIGFUR Stipulation allowing EDIT and the provisional revenues to be flowed back based on a uniform cents per kWh basis is inappropriate and is hereby not approved;

25. That all federal unprotected EDIT and provisional revenues shall be flowed back based on the amounts each rate class paid, as recommended by Public Staff witness Floyd;

26. That the jurisdictional and class cost allocation methodologies proposed by the Company are approved and shall be implemented;

27. That DEC shall set the OPT-VSS off-peak energy charge at 3.0222 cents/kwh and the on-peak energy charge shall be increased by a percentage amount that is equal to half of the overall percentage increase for the OPT-VSS rate schedule. The demand charges for the OPT-VSS rate schedule shall be adjusted by the

amount necessary to recover the final OPT-VSS revenue target. Grid Improvement Plan costs allocated to OPT-V customers shall be recovered via OPT-V demand charges;

28. That the aspects of rate design agreed upon in the Public Staff Second Partial Stipulation are approved and shall be implemented;

29. That the Company shall conduct a comprehensive Rate Design Study as outlined in § IV.E of the Public Staff Second Partial Stipulation and further described herein with broad stakeholder engagement facilitated by a third party to be engaged by the Company; that the Company shall initiate the Rate Design Study with stakeholders no later than 30 days following the date of this Order; that the Company shall file quarterly status reports in this docket detailing the work of the Rate Design Study participants; and that the Company shall file a comprehensive roadmap and timeline for proposing new rate designs and identifying areas for additional study within 12 months of the date of this Order;

30. That the Company shall conduct an independent review and audit of its M&S inventory, to be performed by the Company's internal Corporate Audit Services department, and as further described in the Public Staff Second Partial Stipulation;

31. That the Company and the Public Staff shall meet to discuss the Company's plant unitization policies and reporting obligations;

32. That the Company's proposed modifications of certain outdoor lighting fees and schedules are approved;

33. That the Company shall convene a stakeholder process that is tasked with addressing affordability issues for low-income residential customers consistent with the terms of this Order;

34. That DEC, in conjunction with the concurrent commitment of Duke Energy Progress, LLC, shall make an aggregate combined shareholder-funded contribution to the Helping Home Fund of $3 million per year for two years (for a total of $6 million).

35. That DEC shall make an annual $2.5 million shareholder-funded contribution to the Share the Warmth Fund in 2021 and 2022, for a total contribution of $5 million.

36. That the Company's Storm Costs are reasonable and prudent;

37. That the terms of the Public Staff First Partial Stipulation providing for a contingent Storm Cost Recovery Rider set at $0 are approved;

38. That DEC's request to defer the Storm Costs in a regulatory asset account until the date that storm recovery bonds are issued pursuant to an approved financing order in accordance with N.C.G.S. § 62-172, or until the Company seeks recovery of the Storm Costs through an alternative method of cost recovery, is hereby approved;

39. That DEC's Prepaid Advantage Program shall be, and is hereby, approved;

40. That the rates for electric utility service applicable to the Prepaid Advantage Program shall be those as stated in Schedule RS, with the basic facilities charge, Renewable Energy Portfolio Standard (REPS) Rider, and any other flat rate per account charge applicable to Schedule RS applied to the Prepaid Advantage Program on a pro rata basis;

41. That DEC's requested waiver of the requirements of Commission Rules R8-8, R8-20 (b), (c), and (d); R8-44(4)(d); R12-8; R12-9(b), (c), and (d); and R12-11(a), (b), (f), (g), (h), (i), (l), (m), (n), and (p), shall be granted, only with respect to service rendered under the Prepaid Advantage Program, and with the following limitations on the waiver:

(a) No disconnection before 3:00 p.m. to allow affected customers as much time as possible to make the necessary payments;

(b) That the Company makes all reasonable efforts to have on file a third-party designee, selected by the customer, who will receive any notice of termination in addition to the customer; and

(c) That the limited waiver to Rule R12-11(m)(2) would expire on June 30, 2021, unless otherwise extended by the Commission;

42. That DEC shall work with the Public Staff to develop a quarterly report on the Prepaid Advantage Program to be filed beginning November 1, 2021, for the Third Quarter of 2021, and quarterly thereafter;

43. That the proposed amendments to DEC's Service Regulations shall be, and are hereby, approved;

44. That the Company shall continue to file semi-annual vegetation management reports as directed in Docket Nos. E-7, Subs 1146 and 1182;

45. That DEC shall recover its costs of deploying AMI meters;

46. That DEC shall recover its Rider MRM costs that are not recovered from customers opting out of AMI meters from all DEC customers;

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

48. That DEC shall remove the costs associated with the LCCT 17 from rate base;

49. That DEC shall remove the costs associated with the Focal Point Project from rate base;

50. That DEC shall recalculate and file the annual revenue requirement with the Commission within ten days of the issuance of this Order, consistent with the findings and conclusions of this Order. The Company shall work with the Public Staff to verify the accuracy of the filing; and

51. That DEC shall file schedules (North Carolina Retail Operations — Statement of Rate Base and Rate of Return, Statement of Operating Income, and Statement of Capitalization and Related Costs) summarizing the gross revenue and the rate of return that the Company should have the opportunity to achieve based on the Commission's findings and determinations in this proceeding.

ISSUED BY ORDER OF THE COMMISSION.

This the 31st day of March, 2021.

NORTH CAROLINA UTILITIES COMMISSION

Kimberley A. Campbell

Kimberley A. Campbell, Chief Clerk

Commissioner ToNola D. Brown-Bland dissents in part.
Commissioner Daniel G. Clodfelter dissents in part.
Commissioner Floyd B. McKissick, Jr., concurs in part and dissents in part.

DOCKET NO. E-7, SUB 1187
DOCKET NO. E-7, SUB 1213
DOCKET NO. E-7, SUB 1214

Commissioner ToNola D. Brown-Bland, dissenting in part:

I respectfully dissent from the Commission's decision to allow the Company to defer the capital costs of eight programs associated with GIP investments and to accept and approve the Second Partial Stipulation as it relates to said investments.

In my opinion, the majority decision on GIP cost deferral is contrary to the ratemaking standards of N.C. Gen. Stat. § 62-133. Use of deferral accounting is generally outside the traditional principles set forth in N.C.G.S. § 62-133(b) and (c), and therefore can only be allowed pursuant to N.C.G.S. § 62-133(d). However, the greater weight of the record evidence compels the determination that the cost items for which deferral is sought – and agreed upon by fewer than all parties of record – are not so unusual, extraordinary, or complex that the Company should be granted an exception to seek recovery of costs outside of the ordinary ratemaking standards established by the General Assembly; nor has the majority made any such finding. I cannot agree that the parties' settlement of this issue overrides or obviates the Commission's duty to make the determinations that are *required* before deferral accounting can be authorized under Chapter 62 of the North Carolina Utilities Act. *State ex rel. Utils. Comm'n v. Stein,* 375 N.C. 870, 926, 851 S.E.2d 237, 273 (2020).

In N.C.G.S. § 62-133(d), the legislature saw fit to provide both consumers of public utility service and public utilities with a "'safety valve'" which permits the Commission to consider facts outside of those prescribed by the ordinary ratemaking standards when those standards "prove inadequate" to allow the Commission to meet its obligation to set just and reasonable rates. *Id.* at 925-26, 851 S.E.2d at 272-73. Our Supreme Court recently clarified, however, that § 62-133(d), the safety valve, is to be relied upon over § 62-133(b) and (c) only "in extraordinary instances in which the traditional ratemaking standards set forth in N.C.G.S. § 62-133 are insufficient." *Id*. That is to say, N.C.G.S. § 62-133(d) is not to be exercised routinely.

To the contrary, "N.C.G.S. § 62-133(d) [does] not allow the Commission to . . . ignore the ordinary ratemaking standards set out elsewhere in N.C.G.S. § 62-133" where use of those principles allows for the establishment of just and reasonable rates. *Id.* at 926, 851 S.E.2d at 273. The "safety valve" is just that, and cannot be applied absent specific determinations of "unusual, extraordinary, or complex circumstances" unable to be addressed by traditional ratemaking standards. In relying on the safety valve, the Commission must reasonably conclude that such circumstances justify a departure from traditional standards, determine that the facts establishing those circumstances must be considered in order to set just and reasonable rates, and provide sufficient explanation as to why divergence from traditional standards is appropriate. *Id.* Such determinations and conclusions are decidedly absent from the majority decision.

In practice, the Commission has long applied virtually the same factors articulated by the Supreme Court in *Stein* before exercising its discretion pursuant to § 62-133(d) when allowing public utilities to recover costs using deferral accounting. The Commission has repeatedly stated that deferral accounting is the exception to the general rule that costs should be recovered from ratepayers and applied to or matched with revenues received during the same time period they were incurred; is contrary to the rule; should be used sparingly; and is not favored as it provides for the future recovery of costs for utility services provided to ratepayers in the past. *See* Order Approving Deferral Accounting with Conditions, *Petition of Duke Energy Carolinas, LLC, for an Accounting Order to Defer Certain Environmental Compliance Costs and the Incremental Costs Incurred*, No. E-7, Sub 874, at 24-25 (N.C.U.C. Mar. 31, 2009).[1] As a result, the Commission consistently requires utilities requesting deferral treatment to make a clear and convincing showing that the costs proposed for deferral are of an unusual or an extraordinary nature or type and that, absent deferral, the requesting utility would experience a negative material impact on its financial condition. *Id.* This requirement ordinarily demands a showing that such costs represent significant, considerably complex, non-routine investments that were unanticipated or beyond the utility's ability to control or plan for the timing of incurring the costs. *See* Order Granting Partial Rate Increase, *Application by Carolina Water Service, Inc. of North Carolina for Authority to Adjust and Increase Rates for Water and Sewer*, Docket No. W-354, Sub 364, at 42-43 (N.C.U.C. March 31, 2020). If the cost items sought to be deferred are not found to be unusual or extraordinary, such determination is dispositive and the materiality of the impact of the costs on the financial condition of the utility is not reached. *See* Order Approving Amended Schedule NS and Denying Deferral Accounting, *Application by Virginia Elec. & Power Co., d/b/a Dominion N.C. Power, for Approval of Amended Schedule NS*, No. E-22, Sub 517, at 11 (N.C.U.C. Mar. 29, 2016).

In this case, as in DEC's last rate case, the items proposed for deferral fail the unusual and extraordinary inquiry. DEC previously proposed to recover costs using deferral accounting for a modernization project it called Power Forward. I agree with Commissioner Clodfelter that GIP as presented in the instant case is primarily a subset, or a whittled down, more compact version, of Power Forward — in its scope, size, and costs. The eight GIP programs that the Public Staff and DEC stipulate as appropriate for

[1] *See also* Order Approving Partial Settlement Agreement and Stipulation, Deciding Contested Issues, Granting Partial Rate Increase, and Requiring Customer Notice, *Application of Aqua North Carolina, Inc. to Adjust and Increase All rates for Water and Sewer Utility Service,* No. W-218, Sub 526, at 41-47, 136-37 (N.C.U.C. October 26, 2020); Order Allowing Deferral Accounting, *Transfer of Certificates of Pub. Convenience and Necessity and Ownership Interests in Generating Facilities from Duke Energy Carolinas, LLC, to Northbrook Carolina Hydro II, LLC, and Northbrook Tuxedo, LLC*, No. E-7, Sub 1181, at 16-18 (N.C.U.C. June 5, 2019); Order Approving Partial Settlement Agreement and Stipulation, Granting Partial Rate Increase, and Requiring Customer Notice, *Application by Aqua N.C., Inc., for Authority to Adjust and Increase Rates*, No. W-218, Sub 497, at 50 (N.C.U.C. Dec. 18, 2018); Order Approving Amended Schedule NS and Denying Deferral Accounting, *Application by Virginia Elec. & Power Co., d/b/a Dominion N.C. Power, for Approval of Amended Schedule NS*, No. E-22, Sub 517, at 11-12 (N.C.U.C. Mar. 29, 2016); Order Approving Deferred Accounting Treatment, *Request by Pub. Serv. Co. of N.C., Inc., for Deferred Accounting Treatment Related to Year 2000 Conversion Costs*, No. G-5, Sub 369, 3-4 (N.C.U.C. Apr. 29, 1997), *aff'd*, Order on Reconsideration (N.C.U.C. June 12, 1997).

deferral treatment are not at all extraordinary or unusual. Neither the GIP programs nor the reasons proffered for their need, as was the case with the programs in Power Forward, are unique or extraordinary to DEC or North Carolina. Rather the GIP programs are update, upgrade, and modernization programs, required of the Company to maintain the electrical distribution system and improve reliability, and are part of the routine, ordinary business of being a vertically integrated electricity provider. Without such programs the electric utility would not be providing quality service.

Further, these requirements are not new to the industry, and it cannot be said that the Company was unaware and unable to plan and time the recovery of the modernization projects approved by the Commission as part of GIP. Instead, a quick review of DEC's parent company's Annual Reports reveals that the Company and its parent have been discussing and planning for grid modification initiatives for a long time. Unlike a catastrophic storm that develops with little notice or warning, the need for grid modification is such a routine circumstance that the Company has openly discussed its intended plans for over ten years. In 2010, the parent company discussed graduating its grid from analog to digital and adding two-way communications capabilities to its system to improve reliability and better serve customers. Moreover, as noted by Commissioner Clodfelter, the Company has been investing in grid modification and some of the proposed GIP programs over several years, further highlighting that this work is a regular part of the Company business and, more importantly, that traditional ratemaking procedures have been adequate. To this day, all decisions as to timing, pace, and amount of spending on grid modification have been largely within the Company's control — again, undermining any finding of extraordinary circumstances that might justify deferral accounting as a means of cost recovery for GIP.

I do not disagree with the proposition that GIP will provide benefits or that the Company's initial GIP proposal has been narrowed, focused, and vetted by stakeholders, including the Public Staff, who have worked together and invested time in coming to agreement and refining DEC's GIP proposals. I also believe that it is wise, given so much uncertainty around the cost estimates for GIP, that the Commission is limiting costs and that the Public Staff will work with the Company to file reports and cost trackers on various details of GIP progress. Yet, none of these considerations establishes that GIP is extraordinary or unusual such that the Company should be allowed to depart from the ordinary ratemaking procedures in § 62-133.

It is my further opinion that parties in this proceeding have misconstrued the language in the Commission's opinion in the 2018 DEC Rate Order. There, the Commission stated the following:

> The Commission can authorize a test for approving a deferral within a general rate case with parameters different from those to be applied in other contexts. Consequently, with respect to demonstrated Power Forward costs incurred by DEC prior to the test year in its next case, the Commission authorizes expedited consideration, and to the extent permissible, reliance on leniency in imposing the "extraordinary expenditure" test.

2018 DEC Rate Order, at 149. This language was not meant to signal any change to the Commission's historical test for deferral accounting. Rather, it was a suggestion that the Commission had that option if it wanted to make a change to the test specific to a request for deferral being considered as part of a general rate case. No such change was made in that Order and no such change has been made in this Order either. The test remains unchanged and still requires a finding of extraordinary and unusual circumstances. Indeed, given the *Stein* decision it is not clear that the Commission *could* craft a test without such a requirement even had it wanted.

Moreover, the second sentence in the passage above relates to a deferral request made outside a general rate case. It is not meant to convey the demise of the historical primary focus of the deferral test, *i.e.*, the extraordinary and unusual circumstance. *See also id.* (explaining unusual or extraordinary determination is primary hurdle for deferral approval). Rather, it addresses the secondary materiality/magnitude aspect of the test in the event that DEC were to seek deferral prior to, and outside of, a general rate case. Had this circumstance occurred, the leniency, the determination of which was not ceded to the Public Staff, was directed only at the "extraordinary *expenditure"* threshold — not the extraordinary or unusual circumstance aspect of the test, which is required by the Supreme Court in *Stein* for the exercise of the Commission's authority pursuant to § 62-133(d).

Finally, like all utilities whose rates for service are set by the Commission, DEC abhors regulatory lag and has from time to time made attempts to eliminate or reduce it by use of the deferral mechanism. However, some lag is an inherent part of the statutory ratemaking process in North Carolina – and has been for decades. While regulatory lag in rates offers some positive aspects to customers – e.g., serving as incentive for cost effective and efficient management of the utility and also serving as a guard against waste and inefficiency – it is understandable that utilities see it as a challenge. If regulatory lag is indeed the driving force behind the request for deferral treatment of GIP costs, the appropriate solution is legislative relief. The Commission should not strain the bounds of its authority to exercise use of a deferral mechanism where the legislature did not intend it to be used.

For these reasons I respectfully dissent.

/s/ Commissioner ToNola D. Brown-Bland
Commissioner ToNola D. Brown-Bland

DOCKET NO. E-7, SUB 1187
DOCKET NO. E-7, SUB 1213
DOCKET NO E-7, SUB 1214

Commissioner Daniel G. Clodfelter, dissenting in part:

I differ from the Commission Opinion on three points and therefore write separately to explain my reasons for doing so.

I. Deferral of Grid Improvement Plan Capital Costs

Deferral accounting is an exception to the basic principle embodied in N.C.G.S. §62-133 that costs are to be allocated and charged to the revenues received in the period during which expenditures were incurred. *State ex rel. Utilities Commission v. Edmisten,* 291 N.C. 451, 468-70, 232 S.E.2d 184, 194-96; *State ex rel. Utilities Commission v. Stein,* Nos. 271A18 and 4901A18, 2020 N.C. LEXIS 1058 (N.C. Dec. 11, 2020), at Slip Opinion 79. For this reason the Commission has established a clear standard for granting deferral accounting treatment. I believe the Commission addresses this standard only in the most cursory fashion and does not properly consider its application to this case.[1] As recently as its March 31, 2020 Order Granting Partial Rate Increase and Requiring Customer Notice in Docket No. W-354, Sub 363 (the CWSNC Order) the Commission reiterated that deferral accounting should be used sparingly and as an exception to the general rule 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 a utility's rates and charges. Paraphrasing from the CWSNC Order, deferral is not favored in part because it typically provides for the future recovery of costs for utility services that were provided to ratepayers in the past. The Commission has found that an exception can be made when reasonable and prudently incurred costs are unusual or extraordinary, in some instances because they were unexpected, and when they are of a magnitude that would result in a material impact on the utility's financial position in the absence of an ability to recover those costs from revenues in future periods. In applying this test the Commission has disfavored deferral treatment for expenditures that are planned or whose timing and amount are under the control of the utility. In this instance the record is clear that the costs for which deferral accounting treatment is requested are among a larger group of ongoing programs to modernize and upgrade DEC's transmission and distribution systems, many of which were commenced and well under way well before deferral accounting was requested in this case, all of which are completely under the Company's control, and, none of which, singly or in combination, present any significant threat to the utility's financial condition or its ability to earn its allowed rate of return.

[1] The discussion of the standard for deferral accounting in the Commission's opinion at page 139 is limited to noting that in the Sub 1146 Order the Commission stated that deferral accounting could be granted under different parameters in a general rate case than when the request was made outside a general rate case. But the opinion does not attempt to articulate what those "different parameters" are or might be. And, as noted elsewhere in this dissent, the Commission has regularly applied its established standard *in general rate cases,* including in Docket No. E-7 sub 1146 and the other Commission decisions cited and quoted in this dissent.

Because deferral accounting is a departure from the basic ratemaking structure set forth in N.C.G.S. § 62-133(a)-(c), it is pertinent to consider the Supreme Court's recent discussion in *Stein*. There the Court set forth four factors that govern the Commission's reliance upon its authority under N.C.G.S. § 62-133(d) to supplement, modify, or depart from the basic ratemaking structure established in §§ 62-133(a)-(c). The four factors identified by the Court in its opinion are essentially a restatement of the Commission's traditional two-prong test for accounting deferrals:

> …we hold that the Commission may employ N.C.G.S. § 62-133(d) in situations involving (1) unusual, extraordinary, or complex circumstances that are not adequately addressed in the traditional ratemaking procedures set out in N.C.G.S. § 62-133; (2) in which the Commission reasonably concludes that these circumstances justify a departure from the ordinary ratemaking standards set out in N.C.G.S. § 62-133; (3) determines that a consideration of these "other facts" is necessary to allow the Commission to fix rates that are just and reasonable to both the utility and its customers; and (4) makes sufficient findings of fact and conclusions of law supported by substantial evidence in light of the whole record explaining why a divergence from the usual ratemaking standards would be appropriate and why the approach that the Commission has adopted would be just and reasonable to both utilities and their customers.

Slip Opinion at 87-88.

The record in this case plainly establishes that DEC does not need accounting deferral treatment to enable it to undertake and move ahead with its grid improvement initiatives (the Grid Improvement Plan or, sometimes, GIP). Public Staff witnesses testified that at the time of this general rate case and without any inducement or protection under a deferral accounting order the Company had already commenced work on twelve of the GIP programs, that it spent about $52 million on those programs during the 2018 test year, and that it had spent another $273 million during 2019.[2] *Tr. vol. 17, 313.* During the update period of February through May 2020, DEC completed and placed in service another $34.7 million of investments in the various GIP programs.[3] *Tr. vol. 22, 61.* In fact DEC's own evidence was that spending on the self-optimizing grid program was outpacing its staff's ability to implement attendant computer programming changes needed to enable complete functionality of those investments, leading to delays in full implementation of some of the system upgrades. *Tr. vol. 29 addendum, 7-8.* Given these facts I am compelled to conclude that the GIP investments are very far from being extraordinary, unusual, or unanticipated; they are instead well-thought out, planned, and executed upgrades and improvements to enhance the performance and the reliability of

[2] Except where otherwise noted, all figures are on a total system basis.

[3] This total of approximately $360 million spent over a period of approximately two and one-half years *without* the benefit of any deferral accounting treatment should be compared to the approximately $800 in GIP program expenditures over the two and one-half years from June 2020 through December 2022 for which the Commission finds deferral treatment to be necessary and appropriate.

the Company's transmission and distribution systems. Maintaining, protecting, adapting, and enhancing reliability and performance of the electric grid are core obligations of any electric utility.

The Company contends that all these investments, and those it wishes to make in the future, are necessary and indeed essential to respond to changes and challenges arising from such things as the deployment of distributed generation and other new grid-edge technologies and from increasing security concerns about cyberattacks on businesses and infrastructure such as the electrical grid. The fact that these improvements may be sound and even necessary does not, however, meet the Commission's standard for deferral treatment. The Company attempted to distinguish its GIP investments from other ongoing spending to upgrade equipment and facilities with newer, more efficient and effective replacements by relying on seven so-called "megatrends." These megatrends, however, are nothing more than general features of North Carolina's evolving demography and economy or else they arise from technological innovations that are affecting many sectors of modern life and do not uniquely affect the electric power industry. They have been at work for many years and are neither accidental, sudden, nor unforeseen. The difficulty with arguing from these megatrends to justify special ratemaking treatment for the company's GIP spending is that the argument simply proves far too much. Virtually every aspect of the Company's traditional model is being affected in some way by one or more of these megatrends. If the megatrends justify special ratemaking treatment for the eight specific GIP programs singled out in the Second Partial Stipulation they very likely could justify similar treatment for all other portions of the Grid Improvement Plan and, for that matter, virtually every new investment the Company wishes to undertake.

Rather than being extraordinarily or unusual I would find DEC's GIP programs to be more analogous to the automated meter reading (AMR) installations for which Carolina Water Service of North Carolina (CWSNC) sought deferral accounting in Docket No. W-354, Sub 364. Both involve the deployment of new technologies that promise substantial efficiencies and new capabilities for the utilities and resulting benefits for customers. In the CWSNC Order the Commission found that CWSNC's meter replacements had been on-going for several years and were anticipated to extend several more years into the future. In that case as in this one, the utility requested deferral accounting to mitigate the effect of regulatory lag on earned returns. The Commission rejected CWSNC's request, noting that the timing of meter replacements was entirely within the control of the Company. The fact that CWSNC's AMR investments spanned many years contributed to the Commission's determination that the investments were part of the regular business of adapting and updating the utility's systems to meet the most up-to-date standards and technologies. The fact that they sought to adopt a new technology and realize significant system benefits enabled by that new technology did not win the day for deferral treatment. The DEC investments presently before the Commission also span many years, some programs starting as early as 2018 and some extending beyond 2022, based on DEC's cost-benefit analyses. Several of them, such as the replacement of oil-filled hydraulic reclosers with remotely operated digital reclosing devices, the replacement of single-use fuses with automated reset fuses, and the replacement of electromechanical relays with remotely operated digital relays are virtually indistinguishable in substance from CWSNC's replacement of manually read water meters with AMR meters.[4]

In this instance several parties who support the Company's deferral accounting request, notably the Public staff, rely heavily, in fact almost entirely, on inferences they draw from the Commission's last DEC general rate order issued June 22, 2018, in Docket No. E-7, Sub 1146 (the Sub 1146 Order). In that case DEC petitioned for creation of an annual revenue rider, or alternatively, to obtain deferral accounting treatment for a set of grid modernization programs it then referred to as Power Forward.[5] In its Sub 1146 Order the Commission found that DEC failed to show that Power Forward costs qualified for deferral accounting treatment. The Sub 1146 Order stated:

> …The Commission finds that DEC has not satisfied the criteria for deferral accounting…. In order for the Commission to grant a request for deferral accounting treatment, the utility first must show that the cost items at issue are adequately extraordinary, in both type of expenditure and in magnitude, to be considered for deferral. Second, the utility has to show that the effect of not deferring such cost items would significantly affect the utility's earned returns on common equity. Although it was uncontested … that DEC's planned Power Forward spend is extraordinary in magnitude, the Commission is unpersuaded [that all of the programs] are unique or extraordinary… DEC [also] failed to show that the effect of not deferring [the] costs would significantly affect its earned returns on common equity.

Sub 1146 Order, at 148.

In the Sub 1146 Order the Commission directed DEC to collaborate with stakeholders to address the myriad issues that had been raised about Power Forward in that rate case. In addition, the Commission stated:

> The Commission can authorize a test for approving a deferral within a general rate case with parameters different from those to be applied in other contexts. Consequently, *with respect to demonstrated Power Forward costs*

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[4] One of the eight GIP programs included in the Second Partial Stipulation involves cybersecurity. As the Commission's opinion notes, DEC witness Oliver testified that these elements of the GIP are essentially the same as those DEC has been funding in the past, only the amount of spending will be increased. *Consolidated Tr. vol. 5, p. 39.* With respect to the cybersecurity programs I also note that the Company has obtained a FERC order permitting it to aggregate its expenditures into a single composite project eligible for AFUDC treatment, thereby allowing the Company to continue to accrue AFUDC until the last component element of its cybersecurity project is placed into service. FERC Docket No. AC19-75-000(Dec. 19, 2019). It is not at all clear how this treatment relates to the deferral accounting treatment requested in this case or why if AFUDC treatment is available for these cybersecurity programs there would be any need for deferral accounting treatment for the cybersecurity programs at all.

[5] The specific programs for which deferral accounting treatment is sought in this case is a subset of the larger set of what DEC refers to as its Grid Improvement Plan, which in turn is itself a substantially modified version - both in scope and magnitude and as to its elements - of the earlier Power Forward initiative.

> *incurred by DEC prior to the test year in its next case*, the Commission authorizes expedited consideration, and *to the extent permissible*, reliance on leniency in imposing the "extraordinary expenditure" test.

Id., at 149 (Emphasis added).

Public Staff witness Maness interpreted the Sub 1146 Order to mean that the Commission is prepared to show leniency as to the financial impact of the Company's request in the instant rate case. That interpretation was not the Commission's intent and it does not comport with the actual language used by the Commission. Rather, the quoted language from the Sub 1146 Order refers to a scenario that did not occur, one in which DEC incurred grid modernization costs before the test year in the current case and requested deferral treatment for those costs in the interim period and outside the parameters of a general rate case. Had that occurred, the Commission was prepared to consider the request in an expedited fashion, outside a general rate case, and was prepared to be lenient in imposing the extraordinary expenditure test, especially if DEC's collaboration with the parties had produced consensus as to the programs whose costs would be deferred. That is simply not the situation now presented to the Commission.

Moreover, the language from the Sub 146 Order relied upon by the Public Staff was directed to the first prong of the Commission's deferral accounting standard – that the expenditures be unusual or extraordinary in type and magnitude – and not to the second prong of that standard. On that issue I believe the pertinent language from the Sub 146 Order is the following statement:

> With respect to deferral, the Commission acknowledges that, irrespective of its determination not to defer specific costs in this case, the Company may seek deferral at a later time outside of the general rate case test year context to preserve the Company's opportunity to recover costs, to the extent not incurred during a test period. In that regard, were the Company in the future before filing its next rate case to request a deferral outside a test year *and meet the test of economic harm,* the Commission is willing to entertain a requested deferral for Power Forward, as opposed to customary spend, costs.

Id., at 149 (emphasis added).

In his direct testimony Public Staff witness Maness stated that the Public Staff would not object if the Commission determined that the ROE impacts from the GIP programs covered by the Second Partial Settlement fall within the range of leniency that the Commission intended in the Sub 1146 Order. *Tr. vol. 20, 539.* Strikingly, however, in response to questions from Commissioner Brown-Bland, witness Maness confessed that absent the quoted language from the Sub 1146 Order he could not conclude that the GIP investments proposed for deferral treatment met the financial impact prong of the Commission's standard. *Tr. vol. 7, p. 32; Consolidated Tr., vol. 7, 35; see also*

Commission Opinion p. 122.[6] DEC witness Oliver confirmed that if the Commission did not grant deferral accounting treatment for the proposed GIP programs, the Company nevertheless would continue to implement them, managing and adjusting to accommodate available resources and timetables in order to do so. *Consolidated Tr. vol. 6, 56.*

Leaving aside the Commission's two-prong test for deferral treatment and the Supreme Court's *Stein* factors defining the Commission's authority to depart from traditional ratemaking principles, there are other features of the Second Partial Stipulation's provisions dealing with GIP programs I find unsettling. One of those involves what exactly it is that the parties are asking from the Commission. Deferral accounting treatment for expenditures made in connection with specific GIP programs is certainly being sought, but there is also something more. DEC witness McManeus testified that it is important for the Commission to make clear that the Commission believes the GIP programs are appropriate undertakings and that the costs of such program can ultimately be recovered from customers, assuming they are found to be reasonable in amount. *Consolidated Tr. vol. 9, 24.* To that end the Second Partial Stipulation of Settlement contains the following paragraph:

> The Stipulating Parties' agreement regarding deferral treatment of GIP costs constitutes only approval of the decision to incur GIP program costs. The Public Staff reserves the right to review costs for reasonableness and prudence.

Second Partial Stipulation § IV.D.

Under questioning from Commissioners neither the Company nor the Public Staff witnesses were able to give completely clear meaning to this provision, seeming to contend that acceptance of this provision commits the Commission to allowing cost recovery for GIP program expenditures in future rate cases while at the same time preserving the Commission's full review of GIP spending under the traditional "prudence" standard. As I interpret it, the Company is seeking prior Commission approval of a list of loosely related programs, a practice this Commission seldom follows outside certificate of public convenience and necessity proceedings.[7] Some of those programs involve

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[6] Even if the Sub 1146 Order were interpreted such that "leniency" is taken to refer to both prongs of the deferral standard, not just the "extraordinary expenditure" prong, it should be noted that the Commission qualified leniency with the phrase "to the extent permissible." The outer boundaries of what is "permissible" are not, and likely could not be, established with certainty. But a virtual abandonment of the requirement that the utility show substantial financial harm is not, I think, within those boundaries. In this regard I note that N.C.G.S. § 62-133(b)(1)a. authorizes the Commission to approve inclusion of construction work in progress in rate base, a mechanism to address regulatory lag similar in some ways to deferral accounting, when the Commission finds such use to be in the public interest "and necessary to the financial stability of the utility in question."

[7] Indeed, as to those elements of the GIP that involve investment in utility plant and equipment, as opposed to expenditures made on such things as planning, operational design and operating management of the grid, if those investments are indeed so extraordinary and unusual as is contended, one may well ask why they are not subject to the certificate of public convenience and necessity requirement set forth in N.C.G.S. 62-110(a), which requires a certificate before construction or operation of "any public utility plant or system," except where such construction or operation occurs in the "ordinary course of business."

primarily operational and business process changes, such as the Integrated Systems Operations Plan, while others involve investments in new hardware and physical infrastructure. The Company did not articulate any set of unifying principles – aside from referring to the so-called "megatrends" – that bring these disparate programs into a single integrated whole. The proposed bifurcated review, which is what I believe the quoted provision is attempting to accomplish, deprives the Commission of the ability when all costs have been incurred and all benefits have been have realized or set in motion to judge whether or not the investment was warranted in the first instance. Although the Second Partial Stipulation contemplates ongoing review of GIP program spending by the Public Staff, it does not set forth any clear or measurable performance goals or targets that must be met in order ultimately for cost recovery to be allowed. According to the Second Partial Stipulation the Public Staff's review will include an evaluation of actual benefits realized compared to anticipated or expected benefits. What will be the way forward if the Public Staff should conclude that expected benefits failed to materialize in any significant degree or were wholly or very largely offset by unexpected or additional costs? In such a case will the quoted provision from the Second Partial Stipulation permit or will it not permit a determination that cost recovery should be denied altogether? Unlike a majority of the Commission, I do not believe an aggregate spending cap on the amount of expenditures for which deferral treatment is allowed is an adequate substitute for clear and measurable performance goals or targets that must be met in order for cost recovery to be allowed.[8]

A second unsettling feature of the Second Partial Stipulation's treatment of the GIP programs involves the increasing tendency for regulated utilities to attempt to string together a series of small scale investments in order to craft some composite whole that can be offered up and proposed for deferral accounting treatment. The evolution first from Power Forward, then to the Grid Improvement Plan, then to a series of multiple, only partially overlapping, settlements between DEC and various individual parties to this proceeding about which GIP programs those parties would support, finally culminating in the Second Partial Stipulation with the Public Staff is a good illustration of the potential problems with this approach to solving the problem of regulatory lag.

In a recent general rate case involving Aqua North Carolina, Inc. (Aqua), Public Staff witnesses expressed reservations about a deferral accounting request that involved the aggregation of many unrelated projects. (*See* Joint Testimony of Windley E. Henry and Charles M. Junes dated May 26, 2020, in Docket No. W-218, Sub 526.) These witnesses testified that Aqua's deferral request was based on "the novel argument that the projects and related costs for which it seeks deferral accounting treatment should be considered not on an individual basis, but in the aggregate." I believe the same could be said of DEC's GIP request in this case. I am concerned with the large number and variety of programs that DEC has included under the GIP umbrella, with cost estimates that could vary by as much as 30 percent, and that contains many investment types that overlap

[8] The "loose approval" treatment afforded here for the proposed GIP programs can be contrasted with the carefully structured provisions in N.C.G.S. § 62-110.1 governing certificates of public convenience and necessity for new generating facilities, which include several clauses authorizing the Commission to modify, revoke, or cancel a previously granted CPCN.

with customary maintenance, repair, and upgrade expenditures. It will, I believe, become increasingly difficult for the Commission to apply the "extraordinary" or "unusual" prong of its established deferral accounting treatment with any degree of integrity or consistency if this practice of aggregating expenditures becomes well established, especially if, as occurred in this case, that aggregate is arrived at by a process of negotiation and settlement among contending stakeholders.

A third feature that gives me pause concerns the future rate impacts of the Commission's approval of the Second Partial Stipulation. It is true that the decision to approve deferral accounting treatment for the GIP program expenditures included in the Second Partial Stipulation has no impact on the rates established in the present case. I cannot ignore, however, the implications of this request for future rate cases. The Company supports its case for the GIP investments by offering cost-benefit analyses that, the Company contends, show strong positive economic benefits from those investments. These analyses covered only some components and subprograms within the larger GIP effort, and they were strongly criticized by several intervenor witnesses as being based on studies or data that were out-of-date, were not well-tailored to the demographics and economy of North Carolina, or were otherwise deficient or flawed in various respects. Even if all those criticisms are valid, it nonetheless remains true that the Company and the contending intervenor adversaries did not disagree on either the directionality or the order of magnitude of one unmistakable feature of the Company's cost-benefit studies. The economic benefits disclosed by those studies center on improvements to service reliability, and they overwhelmingly flow to the benefit of the industrial and commercial customer classes. See *Commission Opinion p. 122.* Yet based on the Company's analysis filed in this case the revenue requirement and resulting rate impact from the GIP programs will fall most heavily on the residential customer class. See *Commission Opinion p. 133.* For me this is a pertinent point.[9]

Witnesses for the Company and supporters of the GIP contended that the Commission should keep separate the present question - whether to grant permission to proceed with the GIP investments and grant deferral accounting treatment - from the question in future rate cases concerning how GIP program costs should be assigned to the different customer classes and, accordingly, reflected in rates. In the face of the extensive evidence presented in this case concerning problems of affordability of electric service, especially for low-income and unemployed North Carolinians and for many small businesses bearing the burden of a year of COVID-19 disruptions, I simply cannot perform this feat. If complications concerning the differential future rate impacts on different customer classes are staring at us from the end of the road, I am not comfortable pre-approving the GIP programs and granting them special ratemaking treatment without

[9] Certain witnesses contended that it is not appropriate to consider the proportionality of the assignment of costs relative to the realization of benefits among the various rate classes. I commend to those witnesses Part I, Chapter 5 of Professor Bonbright's treatise, *Principles of Public Utility Regulation* (1960), where he discusses the use of the concepts of "value" and "benefit" in ratemaking. Summarizing the different theories and ways in which those concepts come into play, he observes" "…[I]n actual rate cases the cost [of service] principle is always given modified interpretation which, while not converting it into a value principle, takes indirect account of the effectiveness of the cost incurrence in contributing to the benefit of the consumers." *Id.* at p. 91.

fully considering how the Commission will manage those complications when they materialize in future rate cases? The better course would be to evaluate actual GIP expenditures made by the Company and actual results achieved for customers in the context of all other issues and decisions that culminate in the setting of just and reasonable rates in a future general rate case. While the Commission's decision to place a cap on the total GIP expenditures eligible for accounting deferral is a useful step, I believe it is an inadequate substitute for the kinds of tools the Commission must have in order to properly grant pre-approval of the kinds of forward-looking expenditures such as the Company's proposed GIP investments.

Although in the end I dissent from the Commission's decision to grant deferral accounting treatment for elements of the proposed GIP, I am nonetheless conflicted about doing so. Increasingly, our present statutes governing ratemaking are proving to be poorly suited to address the types of investments that utilities are making and must continue to make in order to transition the electricity grid to the new world of distributed generation from renewables, non-wires solutions to grid reliability and capacity issues, and the two-way power flows that result from these first two trends, not to mention looming electrification of the transportation and real estate sectors and new challenges to grid reliability and resiliency due to cyberattacks and severe weather events. The fundamental paradigm by which rates are derived from examination of historic expenditures was adequate for a time when the electricity system was more stable and when major capital investments were largely centered on the addition of new centralized generating plants built to accommodate increases in aggregate system load. That paradigm does not work well now.

Even under the traditional ratemaking paradigm the General Assembly has shown an understanding of the need for tools that would enable what I would call "forward-looking" or, alternatively, "rapid response" ratemaking treatment in instances involving major capital expenditures or concerns about regulatory lag. In 2013 the General Assembly enacted N.C.G.S. § 62-133.12 to alleviate the effects of regulatory lag by allowing for recovery outside a general rate case of some portion of incremental depreciation expense and capital costs for eligible water and wastewater infrastructure projects that are placed into service between general rate cases. I believe the same recognition underpins N.C.G.S. § §62-133(b)(1)a. and 62-133.1(b)(1)b., which establish the Commission's authority, under the circumstances and conditions spelled out in those statutes, to include in rate base construction work in progress, and also N.C.G.S. § 62-110.7, which governs advance review and approval of nuclear power plant development. To date, however, for investments of the type exemplified by the GIP programs, no such special statutory treatment has been enacted, and thus the Commission is left to operate within the limits established by N.C.G.S. § 62-133(a)-(c), supplemented by § 62-133(d) as interpreted by the Supreme Court in *Stein.*

I wholeheartedly support efforts to change the existing ratemaking paradigm embodied in Chapter 62, and I was encouraged by the progress made in the consideration of SB 559 in the 2019-2020 session of the General Assembly. Though that legislation ultimately was not enacted, it will not be the last such effort. Recommendations coming from stakeholder working groups convened to flesh out the Clean Energy Plan developed in response to Executive Order 80 contain a number of options and possible changes to the General Statutes that could, if adopted, enable the Commission better to manage approval, oversight, and cost recovery for initiatives such as DEC's Grid Improvement Plan.[10] Unfortunately, though, for now we must decide proceedings before us following the statutes we have. The Commission's decision is ultimately based not on substantial evidence that is material and sufficient under current law and precedent but instead on a wish and a hope – a wish that the Commission had the kind of authority I believe is essential for the future and a hope that the General Assembly will, even if after the fact as far as the present proceeding goes, take action that validates the policy rationale for the decision in this case. I share both that wish and hope, but I am constrained by the tools that we have been given by the General Assembly until they are changed.

I differ from the majority in that I do not believe a partial settlement of disputed issues, even more so an agreement by fewer than all parties, can substitute for the Commission's lack of authority to engage in "forward looking" ratemaking, that it can override or displace the Commission's existing standard for deferral accounting treatment, nor that it can rectify the deficiencies in the evidence submitted to the Commission under its traditional test for an accounting deferral order. While settlements are certainly to be encouraged, I believe the Commissions' deference to the Second Partial Stipulation in this instance fails to comply with the requirement that the Commission exercise its own independent judgment with respect to the matters embraced in the settlement. This is especially troubling in that the settlement overrides a Commission standard that is to be used sparingly and whose use is to be considered an exception to general ratemaking principles. If parties come to know and understand that by settlement they can circumvent the Commission's standard, then what will be left of the notions of "sparingly" or "exceptional"? With respect to the Commission's decision granting deferral accounting treatment for certain of the company's GIP expenditures I must therefore dissent.

II. Coal Ash Disposal and Groundwater Remediation Costs

Though I endorse much of the Commission's discussion of the proposed settlement relating to coal ash disposal and remediation costs, I cannot go the full distance. Pending before the Commission now are two matters only – first, a decision establishing rates in this proceeding and second, a decision on remand from the Supreme Court in Docket No. E-7 sub 1146. I agree with the Commission majority that those portions of the CCR Settlement that address the two pending matters are appropriate and would produce rates that are fair and reasonable to the company and to ratepayers. In arriving at this conclusion I have relied on the combined effect of the settlement of the case on remand and the settlement of the current proceeding. Considering them separately and individually, however, I would not reach the same result. For reasons

[10] See North Carolina Energy Regulatory Process – In Fulfillment of the North Carolina Clean Energy Plan B-1 Recommendation, December 22, 2020 Summary Report and Compilation of Outputs (https://files.nc.gov/ncdeq/climate-change/clean-energy-plan/2020-NERP-Final-Report.pdf).

discussed in my dissenting opinion in Docket No. E-7 sub 1146 I do not consider the result in that case to be one that yielded just and reasonable rates, and the proposed CCR Settlement would reaffirm and leave unchanged that result. At the same time, however, the CCR Settlement would impose a greater reduction in the cost recovery request for ash basin closure and groundwater remediation expenditures in this case than I was prepared to impose, based upon the evidence offered in this case and the specific facts concerning the particular expenditures for which cost recovery is sought in this case.

I am unclear as to exactly what position the Commission is taking with respect to the forward-looking provisions of the CCR Settlement. *See Commission Opinion, Findings of Fact 23, 24 and 26.* Aside from authorizing the Company to continue to defer ash basin closure and remediation expenditures in the same manner as was approved for the costs in this case and those in Docket No. E-7 sub 1146, at this point I would take no position on those portions of the CCR Settlement that speak to the treatment of ash basin closure and groundwater remediation costs in future general rate cases. Those matters are not now at issue and thus are not before the Commission. Whether the financial terms the settling parties propose be applied to cost recovery requests in future rate cases will produce just and reasonable rates is, I believe, a question that can only be decided when the Commission has before it all the facts and circumstances of those future cases.

Finally, while I join in the Commission's directive, *Commission Opinion p. 75,* that the Company consider in its next general rate case the option of including in base rates a normalized allowance for ongoing coal ash expenditures, I would also have been prepared to go further and adopt such a cost recovery mechanism in the present case for all or some of the company's ongoing costs. When this mechanism was suggested by the Company in Docket No. E-7 sub 1146, it was rejected by the Commission. Two fundamental developments since that time have made the option viable and even, in my view, preferable to what the Commission and the parties have called the "spend-defer-recover" method employed to date. The Company's settlement with the Department of Environmental Quality means that from this point the nature and scope of the tasks that the Company will be required to perform in order to close the remaining ash impoundments and remediate detected groundwater contamination are no longer subject to regulatory uncertainty and litigation. They can be predicted and planned with a much greater degree of accuracy than was possible in 2017. Additionally, the Company has now substantially completed or is well advanced toward completing impoundment closure activities at its Dan River, Riverbend, and Buck facilities and has thereby gained valuable experience in forecasting the costs it may reasonably expect to incur to perform various closure activities. Because this cost recovery option would provide the company consistent, predictable current cash flow to fund impoundment closure activities, not requiring it to tap its credit facilities or use shareholder capital, and because it would do so at lower cost to ratepayers, I believe it to be the superior method for achieving just and reasonable rates.

III. Cost Allocation Matters

Briefly, I note that my views on the appropriateness of using the single coincident peak method for allocating among customer classes the demand portion of production costs and of using the minimum system method for allocating a portion of distribution system costs on a per customer basis remain unchanged from my dissents in Docket Nos. E-2 sub 1142 and E-7 sub 1146. I believe these two cost allocation methodologies are flawed, and in the case of the so-called “minimum system” method they are increasingly being abandoned by regulatory commissions in favor of the “basic customer charge” method. In this case the Company was unable to produce any new, different, or more persuasive reasons for me to reconsider my prior positions. I am, however, hopeful that the two stakeholder forums initiated by the Commission’s decision in this case – one intended to take a comprehensive review of matters of rate design and the other dealing with problems of affordability -- will permit a more extensive debate about how these flawed cost allocation methods help drive many of the problems that exist in current customer classifications and class rate designs and with respect to the affordability of service for low-income residential customers.

For the foregoing reasons and with respect to the issues discussed in this opinion, I dissent.

/s/ Daniel G. Clodfelter
Commissioner Daniel G. Clodfelter

DOCKET NO. E-7, SUB 1213
DOCKET NO. E-7, SUB 1214
DOCKET NO. E-7, SUB 1187

Commissioner Floyd B. McKissick, Jr., dissenting in part, and concurring, with an explanation:

Deferral of Grid Modernization Expenses

The majority has accepted the Second Partial Stipulation as it relates to eight separate projects which they are now collectively referring to as being part of a Grid Modernization Program. I must dissent on this issue. In my opinion, these projects fail to satisfy the four factors identified by the Supreme Court in *Stein*, which are substantially the same as the two-pronged test historically applied by the Commission for accounting deferrals. The Commission's acceptance of the Second Partial Stipulation in light of these circumstances has the potential to incentivize applicants in future cases where deferral treatment is sought to use the give and take of compromise to seek the deferral treatment of projects which would not otherwise meet or satisfy standards of the court or of this Commission. In addition, the Company commenced substantial work pursuant to its Grid Modernization Program before it sought deferral accounting treatment in this proceeding, and testimony provided by the Company's witnesses during the hearing clearly and unambiguously expressed an intent on the Company's behalf to carry out its Grid Modernization Program regardless of whether deferral accounting treatment was granted by the Commission in this proceeding.

Coal Ash Disposal

Concurrence with Explanation

After conducting a critical review of the CCR Settlement, I am persuaded that the give and take of the compromise process has resulted in an agreement between the parties to the stipulation, those parties being DEC, the Public Staff, the NC Attorney General's Office, and the Sierra Club to the issues set forth and agreed upon in the CCR Settlement Agreement. It is I believe uncontroverted, but nonetheless worth stating, that this agreement cannot legally bind other parties or intervenors in the future through the year 2030 that were not parties to the agreement. Therefore, intervenors in the future that were not parties to the CCR Settlement would be free to raise issues or contentions they deem relevant and appropriate relating to these issues. Likewise, future Commissions would have a duty and responsibility to hear and receive evidence on the issues at an appropriate time, including evidence relating to the issues agreed upon by the stipulating parties in the CCR Settlement. This includes issues related to the treatment of coal ash basin closures and remediation cost in future general rate cases.

As noted in the Commission's Order, the CCR Settlement does not involve a contemporaneous cost recovery mechanism which could be of substantial benefit to ratepayers as well as to DEC. I am of the opinion that a properly structured cost recovery mechanism would be far preferable to the "spend-defer-recover" method in the CCR Settlement Agreement.

/s/ Commissioner Floyd B. McKissick, Jr.
Commissioner Floyd B. McKissick, Jr.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1142
DOCKET NO. E-7, SUB 1146

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1142 In the Matter of Application by Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina DOCKET NO. E-7, SUB 1146 In the Matter of Application by Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	)	ORDER ON REMAND ACCEPTING CCR SETTLEMENT AND AFFIRMING PREVIOUS ORDERS SETTING RATES AND IMPOSING PENALTIES

BY THE COMMISSION: On February 23, 2018, and June 22, 2018, respectively, the Commission issued orders in the above-captioned dockets establishing rates in response to applications for rate increases filed in 2017 by Duke Energy Progress, LLC (DEP), and Duke Energy Carolinas, LLC (DEC; collectively, the Companies). In each case, the Commission found that the company had become subject to new requirements related to the management of coal ash, or coal combustion residuals (CCR), and that each had incurred significant costs to comply with these new legal requirements. Several parties, including the Attorney General's Office (AGO), argued that ratepayers should not be forced to cover costs caused by the Companies' years of failure in managing their coal ash basins. The Public Staff proposed an "equitable sharing" arrangement which would have resulted in a 50/50 sharing of costs between the Companies' ratepayers and shareholders.

The Commission rejected the arguments of the AGO, Sierra Club, the Public Staff, and others and allowed the Companies to recover substantially all of their CCR costs. In Docket No. E-2, Sub 1142 (Sub 1142), the Commission allowed DEP to recover $232.4 million in CCR costs incurred during the period from January 1, 2015, through August 31, 2017; required DEP to amortize the cost recovery in rates over a five-year period; allowed DEP to earn a return[1] on the unamortized balance during the five-year

[1] While frequently referred to as "return," to clarify, the Companies were allowed to recover the costs incurred to finance the CCR costs during the amortization period.

amortization period; and assessed a $30 million management penalty (2018 DEP Rate Order). Similarly, in Docket No. E-7, Sub 1146 (Sub 1146), the Commission allowed DEC to recover $545.7 million in CCR costs incurred during the period from January 1, 2015, through December 31, 2017; required DEC to amortize the cost recovery in rates over a five-year period; allowed DEC to earn a return on the unamortized balance during the five-year amortization period; and assessed a $70 million management penalty (2018 DEC Rate Order).

Appeal and Remand

Several parties, including the AGO, Sierra Club, and the Public Staff, timely appealed the Commission's rate case orders to the North Carolina Supreme Court pursuant to N.C.G.S. § 62-90 on the CCR cost recovery and other issues. While these appeals were pending, the Companies each filed another application for increase in rates — DEC on September 30, 2019, and DEP on October 30, 2019.

On December 11, 2020, after the close of the evidentiary record in the 2019 rate cases before the Commission, the Court issued its opinion substantially affirming the Commission's orders in the 2017 DEC and DEP rate cases, including issues on appeal regarding discharges to surface waters and increases in the basic facilities charge. However, the Court reversed those portions of the Commission's order rejecting the Public Staff's equitable sharing proposal and remanded the cases for additional findings and conclusions related to the Commission's consideration of "all other material facts" relevant to the Public Staff's proposal regarding recovery of CCR costs "as required by N.C.G.S. § 62-133(d)." *State ex rel. Utils. Comm'n v. Stein*, 375 N.C. 870, 947, 851 S.E.2d 237, 286 (2020) (*Stein*).

As the Court notes in its opinion, the issues on appeal of the 2017 rate cases related to the recovery of CCR costs were: (1) whether the costs were properly classified as property used and useful or as operating expenses; (2) whether these costs were reasonably incurred; and (3) whether the Commission's decision to award a return on the unamortized balance of the costs was lawful. *Id*. at 900, 851 S.E.2d at 257. In summary, the Court concluded

> that the Commission did not err by: (1) allowing the inclusion of a large majority of the utilities' coal ash costs in the cost of service used for the purpose of establishing the utilities' North Carolina retail rates; (2) interpreting N.C.G.S. § 62-133(d) to authorize the Commission, in the exercise of its discretion, to allow a return on the unamortized balance of the deferred operating expenses . . . . On the other hand, we hold that the Commission erred by rejecting the Public Staff's equitable sharing proposal without properly considering and making findings and conclusions concerning "all other material facts" as required by N.C.G.S. § 62-133(d). As a result, we affirm the Commission's decisions, in part, and reverse and

> remand the Commissions' decisions for further proceedings not inconsistent with this decision, in part.

Id. at 946-47, 851 S.E.2d at 286.

In challenging the reasonableness and prudence of the CCR costs, both the AGO and the Public Staff argued that the Commission did not adequately consider their admitted evidence of violations of environmental laws in allowing recovery of the full amount of the CCR costs. With respect to the reasonableness and prudence of the CCR costs, the Court agreed that "the record contains ample evidentiary support for the Commission's determination . . . that the intervenors had failed to elicit sufficient evidence to satisfy the burden of production imposed upon them in *Bent Creek*," and "that the intervenors failed to identify and quantify the specific costs that should have been disallowed as unreasonable and imprudently incurred . . . ." *Id*. at 911-12, 851 S.E.2d at 263-64. The Court further agreed with the Commission and with Public Staff witness Lucas "that it would be difficult, if not impossible, to quantify, in even the most general sense, the costs which the utilities would have incurred had they handled the coal ash stored at their facilities in a manner that differed from what they actually did or if specific alleged environmental violations had not occurred." *Id*.

In response to the AGO and Public Staff arguments that much of the CCR costs were operating expenses and not property used and useful — thus ineligible for rate base treatment or to earn a return — the Court noted that the formula set forth in N.C.G.S. § 62-133(b) provides "a workable framework that can be used to establish just and reasonable rates," *id*. at 921, 851 S.E.2d at 270, but that the Commission did not err in relying upon N.C.G.S. § 62-133(d) in these cases in "deferring certain extraordinary costs, amortizing them to rates, and allowing the utility, in the exercise of the Commission's discretion, to earn a return upon the unamortized balance . . . ." *Id*. at 922, 851 S.E.2d at 270. Quoting *State ex rel. Utilities Commission v. Edmisten*, 291 N.C. 327, 230 S.E.2d 651 (1976), the Court held that N.C.G.S. § 62-133(d) "expressly empowers the Commission to 'consider all other material facts of record that will enable it to determine what are reasonable and just rates.'" *Id*. at 345, 230 S.E.2d at 662 (citing *State ex rel. Utils. Comm'n v. Morgan*, 277 N.C. 255, 177 S.E.2d 405 (1970)). *See also State ex rel. Utils. Comm'n v. Thornburg*, 325 N.C. 463, 385 S.E.2d 451 (1989); *State ex rel. Utils. Comm'n v. Nantahala Power & Light Co*., 313 N.C. 614, 332 S.E.2d 397 (1985); *State ex rel. Utils. Comm'n v. Duke Power Co*., 305 N.C. 1, 287 S.E.2d 786 (1982); *State ex rel. Utils. Comm'n v. Pub. Serv. Co*., 257 N.C. 233, 125 S.E.2d 457 (1962).

> Thus, this Court's prior decisions, while failing to delineate the exact contours of the Commission's authority pursuant to N.C.G.S. § 62-133(d), have clearly indicated that N.C.G.S. § 62-133(d) is available to the Commission for the purpose of dealing with unusual situations and that the authority granted to the Commission pursuant to N.C.G.S. § 62-133(d) is not limited by the more specifically stated ratemaking principles set out elsewhere in N.C.G.S. § 62-133(b). Simply put, if the Commission's authority pursuant to N.C.G.S. § 62-133(d) could only be exercised in a

manner that coincided with the Commission's authority as delineated in the other provisions of N.C.G.S. § 62-133, the enactment of N.C.G.S. § 62-133(d) would have been a purposeless undertaking.

After carefully examining our reported decisions construing N.C.G.S. § 62-133(d), we conclude that this statutory provision provides the Commission with an opportunity to consider facts that, while not specifically relevant to the ordinary ratemaking determinations required by N.C.G.S. § 62-133(b), should necessarily be considered in establishing rates that are just and reasonable to both the utility and the using and consuming public. For that reason, we reject the notion that the traditional rules governing the inclusion of costs in a utility's rate base pursuant to N.C.G.S. § 62-133(b)(1) and in a utility's operating expenses pursuant to N.C.G.S. § 62-133(b)(3) limit the scope of the Commission's authority pursuant to N.C.G.S. § 62-133(d), with any such determination being fundamentally inconsistent with the apparent legislative intent to use N.C.G.S. § 62-133(d) to provide a "safety valve" available to the Commission when ordinary ratemaking standards prove inadequate. However, as our earlier admonition that the predecessor to N.C.G.S. § 62-133(d) did not allow the Commission to "roam at large in an unfenced field" clearly indicates, N.C.G.S. § 62-133(d) does not give the Commission license to ignore the ordinary ratemaking standards set out elsewhere in N.C.G.S. § 62-133 in cases in which the use of those principles, without the necessity to consider "other facts," allows for the establishment of just and reasonable rates for the utility in question. Instead, N.C.G.S. § 62-133(d) provides the Commission with limited authority to take a holistic look at the cases that come before it in order to ensure that the limitations inherent in the ordinary ratemaking standards enunciated in N.C.G.S. § 62-133 do not preclude the Commission from carrying out its ultimate obligation to establish rates that are just and reasonable in extraordinary instances in which the traditional ratemaking standards set out in N.C.G.S. § 62-133 are insufficient. As a result, consistently with the results reached in the decisions that we have summarized above, we hold that the Commission may employ N.C.G.S. § 62-133(d) in situations involving (1) unusual, extraordinary, or complex circumstances that are not adequately addressed in the traditional ratemaking procedures set out in N.C.G.S. § 62-133; (2) in which the Commission reasonably concludes that these circumstances justify a departure from the ordinary ratemaking standards set out in N.C.G.S. § 62-133; (3) determines that a consideration of these "other facts" is necessary to allow the Commission to fix rates that are just and reasonable to both the utility and its customers; and (4) makes sufficient findings of fact and conclusions of law supported by substantial evidence in light of the whole record explaining why a divergence from the usual ratemaking standards would be appropriate and why the approach that the

> Commission has adopted would be just and reasonable to both utilities and their customers.

Stein, 375 N.C. at 925-26, 851 S.E.2d at 272-73 (footnote omitted).

After affirming the Commission on these issues, the Court stated that while subsection (d) "'empowers' the Commission to consider all material facts of record in setting just and reasonable rates, . . . this authority [is] coupled with a concomitant obligation on the Commission's part to consider all potentially relevant facts in formulating its decision." *Id*. at 930-31, 851 S.E.2d at 276. The Court remanded the case for further proceedings, concluding that it was "not persuaded that the Commission fulfilled its duty to consider *all* of the material facts of record revealed in the record in determining whether to adopt the ratemaking approach proposed by the utilities and to reject the Public Staff's equitable sharing proposal utilizing the authority granted to it pursuant to N.C.G.S. § 62-133(d)." *Id*. at 931, 851 S.E.2d at 276. Thus, the Commission was directed on remand to "consider[] all of the potentially relevant facts and circumstances and explain[] the manner in which it has chosen to exercise its discretion by making appropriate findings and conclusions that have adequate evidentiary support" in rejecting or adopting "the Public Staff's equitable sharing proposal, either as proposed or in some modified form." *Id*. at 932, 851 S.E.2d at 277 (citation and footnote omitted).

Settlement and Procedure on Remand

Following issuance of the Supreme Court's decision, on December 17, 2020, the Commission issued an Order Requesting Comments on Procedure on Remand, which, among other things, sought the parties' comments on the procedure to be employed in addressing the Court's remand of the cases. On January 11, 2021, the Public Staff, the AGO, DEP, DEC, Carolina Industrial Group for Fair Utilities II (CIGFUR II) and Carolina Industrial Group for Fair Utilities III (CIGFUR III), and Sierra Club filed a Joint Submission Regarding Procedure Upon Remand.

On January 25, 2021, DEP, DEC, the AGO, Sierra Club, and the Public Staff (collectively, CCR Settling Parties) filed a Coal Combustion Residuals Settlement Agreement (CCR Settlement) resolving on a comprehensive basis the multiple CCR cost recovery issues present in the 2017 and 2019 rate cases.

On January 29, 2021, the Companies filed the testimony of Stephen G. De May in support of the CCR Settlement. Contemporaneously, the CCR Settling Parties, along with CIGFUR II and CIGFUR III, filed a Supplement to Joint Submission Regarding Procedure on Remand and requested that the Commission reopen the 2017 rate cases and admit as new evidence the CCR Settlement and supporting testimony for consideration on the remand issue without the need to hold evidentiary hearings in connection with its further consideration of equitable sharing. On February 5, 2021, the Public Staff filed the testimony of Michael C. Maness in support of the CCR Settlement.

On February 12, 2021, the Commission issued an Order Reopening Records, Allowing Testimony or Comments on Proposed Settlement, and Allowing Requests for Hearing granting the motion to reopen the rate case dockets and to accept into evidence the CCR Settlement and the supporting testimony filed by DEC, DEP, and the Public Staff. The order also directed parties to file testimony or comments on the CCR Settlement, or to file a request for a hearing on the CCR Settlement and supporting testimony, on or before February 19, 2021. The Commission further stated that a party's choice not to file a request for a hearing would be deemed as a waiver by that party of its right to cross-examine the witnesses who provide testimony regarding the CCR Settlement.

On February 17, 2021, the Commission issued an Order Requiring Responses to Commission Questions. On February 23, 2021, DEP and DEC filed verified responses to the Commission's questions.

No additional evidence, supporting testimony, comments, or requests for a hearing on the CCR Settlement were received.

Based upon the foregoing and the entire record in these proceedings the Commission on remand makes the following

FINDINGS OF FACT

1. Since 2014, the Companies have become subject to new legal requirements relating to its management of coal ash, including the North Carolina Coal Ash Management Act (CAMA) enacted in 2014 and amended in 2016, and the United States Environmental Protection Agency (EPA) final rule — the Coal Combustion Residuals Rule (CCR Rule) — promulgated in 2015. These state and federal laws and regulations introduced new requirements for the management of coal ash, or coal combustion residuals (CCR), and mandated the closure of the coal ash basins at all of DEP's and DEC's coal-fired power plants. The Companies have incurred significant costs to comply with these new legal requirements (CCR costs).

2. In the Sub 1142 proceeding DEP sought recovery of its actual CCR costs incurred from January 1, 2015, through August 31, 2017, along with financing costs at its approved weighted average cost of capital (WACC), which on a North Carolina retail jurisdiction basis amounted to approximately $241.9 million. In the 2018 DEP Rate Order, the Commission concluded that DEP was entitled to recover these CCR costs, less a disallowance of $9.5 million, for a total amount of approximately $232.4 million. The Commission also concluded that the actual CCR costs incurred by DEP, less the $9.5 million, are known and measurable, reasonable and prudent, and used and useful in the provision of service to DEP's customers, and thus DEP was entitled to recover these costs through rates. Further, the Commission concluded that, under normal circumstances, the five-year amortization period proposed by DEP was appropriate and reasonable and absent any management penalty should be approved, with DEP entitled to earn a return on the unamortized balance.

3. Also in the 2018 DEP Rate Order, the Commission concluded that a management penalty in the approximate sum of $30 million was appropriate as to DEP's CCR remediation expenses. The Commission implemented the penalty by directing DEP to amortize the $232.4 million over five years with a return on the unamortized balance and then to reduce the resulting annual revenue requirement by $6 million for each of the five years.

4. In the Sub 1146 proceeding DEC sought recovery of its actual CCR costs incurred from January 1, 2015, through December 31, 2017, along with financing costs at its approved WACC, which on a North Carolina retail jurisdiction basis amounted to approximately $545.7 million. The Commission in the 2018 DEC Rate Order concluded that DEC was entitled to recover these CCR costs. The Commission also concluded that the actual CCR costs incurred by DEC are known and measurable, reasonable and prudent, and used and useful in the provision of service to DEC's customers, and thus DEC was entitled to recover these costs through rates. Further, the Commission concluded that, under normal circumstances, the five-year amortization period proposed by DEC was appropriate and reasonable and absent any management penalty should be approved, with DEC entitled to earn a return on the unamortized balance.

5. Also in the 2018 DEC Rate Order the Commission concluded that a management penalty in the approximate sum of $70 million was appropriate as to DEC's CCR remediation expenses. The Commission implemented the penalty by directing DEC to amortize the $545.7 million over five years with a return on the unamortized balance and then to reduce the resulting annual revenue requirement by $14 million for each of the five years.

6. On January 25, 2021, the CCR Settling Parties filed the CCR Settlement in the 2017 and 2019 rate case dockets resolving the issues among them related to CCR cost recovery. Not all parties to the 2017 and 2019 rate cases are parties to the CCR Settlement.

7. The CCR Settlement, which is the product of the give-and-take in settlement negotiations between the CCR Settling Parties, is material evidence in these dockets and is entitled to be given appropriate weight in these proceedings, along with other evidence adduced by the Companies and intervenor parties.

8. Section III.E.i and ii of the CCR Settlement provide that the CCR Settling Parties request and support that on remand in the 2017 rate case dockets, the Commission leave in place its decisions in the Subs 1142 and 1146 proceedings, including the Cost of Service Penalties.

9. Section III.E.iii and iv also provide that the amount of CCR Costs and Financing Costs sought for recovery in 2019 DEP and DEC rate cases will be reduced by $261 million and $224 million, respectively. Additionally, Section III.E provides for the recovery of Financing Costs sought for recovery in the 2019 rate cases accrued during the Deferral Period, calculated at the WACC, and provides for the recovery of Financing

Costs during the five-year Amortization Period, calculated using: (i) DEP's and DEC's cost of debt as stipulated by the Companies and the Public Staff in the Second Partial Stipulation adjusted as appropriate to reflect the deductibility of interest expense; (ii) a cost of equity 150 basis points below the stipulated rate of return on common equity of 9.60%; and (iii) a 48% debt and 52% equity capital structure.

10. Section III.F of the CCR Settlement provides that the amount to be recovered for Future CCR Costs defined as costs incurred by DEP from March 1, 2020, through February 28, 2030, along with associated Financing Costs incurred during the Deferral Period, will be reduced by $162 million but allows for recovery of any remaining CCR Costs, subject to determination by the Commission that such costs were reasonably and prudently incurred. Similarly, Section III.F provides that the amount to be recovered of Future CCR Costs incurred by DEC from February 1, 2020, through January 31, 2030, along with associated Financing Costs incurred during the Deferral Period, will be reduced by $108 million but allows for recovery of any remaining CCR Costs, subject to determination by the Commission that such costs are reasonably and prudently incurred. Additionally, Section III.F provides for recovery of Financing Costs during the applicable Deferral Period, calculated at the WACC, and permits recovery of Financing Costs during the applicable Amortization Period, calculated using a reduced cost of equity.

11. Section III.D.i of the CCR Settlement provides that the Public Staff, the AGO and the Sierra Club (collectively, Intervenor Settling Parties) waive their right to assert that future CCR costs should be shared between the Companies and their respective ratepayers through equitable sharing of the costs or other adjustment except as provided in the CCR Settlement. Section III.D.ii provides that the Intervenor Settling Parties waive their right to challenge future CCR costs on the basis that the Companies' prior coal ash management practices were inadequate and led to unreasonable CCR costs being incurred or led to CCR costs being unreasonably higher than otherwise would have been incurred. Section III.D.iii of the CCR Settlement provides that the Intervenor Settling Parties reserve their right to propose an adjustment to future CCR costs on the grounds that the costs were otherwise unreasonable or were imprudently incurred.

12. Section III.G of the CCR Settlement provides for an allocation between DEP, DEC, and their customers of any proceeds from ongoing coal ash insurance litigation.

13. The provisions of the CCR Settlement applicable to the instant dockets are just and reasonable and in the public interest in light of all of the evidence presented and are not inconsistent with the Court's opinion in *Stein* remanding the 2017 rate cases to the Commission for additional proceedings.

DISCUSSION OF EVIDENCE AND CONCLUSIONS

The evidence supporting these findings of fact is found in the verified applications, and Form E-1s filed in both Subs 1142 and 1146; the CCR Settlement; the testimony and exhibits of the expert witnesses in both the 2017 and 2019 rate cases; the settlement testimony of DEP and DEC witness De May and Public Staff witness Maness; and the entire record in each of these proceedings.

The testimony and exhibits in these proceedings are voluminous. The Commission has carefully considered all the evidence and the records as a whole. However, the Commission has not attempted to recount every statement of every witness in this Order. The Commission incorporates by reference the evidence summarized in the 2018 DEP and DEC Rate Orders and finds and affirms all other findings of fact in those orders necessary to support the discussion and conclusions set forth below.

Summary of the Evidence

Companies' Settlement Testimony

In support of the January 25, 2021 CCR Settlement witness De May testified that the CCR Settlement represents a balanced solution that resolves the coal ash cost recovery debate in North Carolina, providing both immediate and long-term savings for customers and long-term certainty for the Companies and their investors and allowing all parties to move forward towards the desired cleaner energy future. He concluded that the CCR Settlement is in the public interest and should be approved.

Witness De May provided an overview of the CCR Settlement. He testified that it resolves among the CCR Settling Parties, subject to Commission approval, CCR cost recovery issues in both the 2017 and 2019 rate cases in a comprehensive manner for the period beginning January 1, 2015, through February 28, 2030 — a period of over fifteen years. Witness De May contended that the CCR Settlement requires the Companies to reduce the amount of coal ash-related costs to be recovered from customers and grants the Companies the ability to earn a return upon the recovered costs at a negotiated cost of equity lower than each Company's allowed rate of return on common equity. The CCR Settlement also provides customers with immediate and future rate reductions — DEP and DEC together will absorb approximately $1.1 billion on a North Carolina system basis through February 2030. Witness De May testified that on a North Carolina retail basis, the net present value of the cost savings to customers (including applicable financing costs) is in excess of $900 million. Witness De May noted that, importantly, a large portion of the rate reduction will occur over the near term, during a period in which many customers are still suffering economic hardship from the COVID-19 pandemic.

Witness De May also summarized the benefits of the CCR Settlement to the Companies. He explained that it "validates and affirms the reasonableness and prudence of [each] Company's ash basin closure strategy," provides more certainty and stability regarding cost recovery, and — by preserving the Companies' ability to recover financing costs, albeit at a reduced rate — preserves their access to much needed capital on reasonable terms, also benefitting customers. Finally, the CCR Settlement — in settling the legacy issue of coal ash cost recovery — allows the collective focus to shift to the future to cleaner sources of energy, while maintaining the Companies' drive to keep electricity affordable and reliable.

Witness De May explained that the CCR Settlement appropriately balances the need for rate relief with the impact of such rate relief on customers. He stated that each Company is pleased that its rates are competitive and below the national average and will remain so under the CCR Settlement, noting that providing safe, reliable, and increasingly clean electricity at competitive rates is key. Witness De May stated that, particularly in light of the current economic conditions faced by customers due to the COVID-19 pandemic, each Company believes the CCR Settlement fairly balances the needs of customers with the need to recover substantial investments made to continue to comply with regulatory requirements and safely provide high quality electric service. He concluded that given the size of the necessary capital and compliance expenditures the Companies face, it is essential that DEP and DEC maintain their financial strength and credit quality for the benefit of their customers.

Public Staff Settlement Testimony

Public Staff witness Maness testified that the CCR Settlement would comprehensively resolve the following CCR cost recovery issues: (1) issues pending before the Commission on remand in the 2017 DEP and DEC rate cases; (2) issues pending before the Commission in the 2019 rate cases; (3) the treatment of CCR costs incurred by DEC from February 1, 2020, through January 31, 2030, and by DEP from March 1, 2020, through February 28, 2030, along with associated Financing Costs; and (4) how any proceeds received from insurance litigation related to CCR costs would be shared by ratepayers, DEC, and DEP.

In addition, witness Maness explained that from the perspective of the Public Staff, the most important ratepayer benefits of the CCR Settlement are: (1) DEC's and DEP's agreement to forego the combined recovery of CCR costs and associated Financing Costs in excess of $900 million, on a present value basis, over the period from January 1, 2015, though January 31, 2030, for DEC and February 28, 2030, for DEP; (2) the allocation of the proceeds of CCR insurance litigation; and (3) the avoidance of protracted litigation over CCR costs and financing costs into 2030 among the CCR Settling Parties. Accordingly, witness Maness stated that the Public Staff believes the CCR Settlement is in the public interest and should be approved.

Standard of Review

The Commission is required to set just and reasonable rates for public utilities. N.C.G.S. § 62-130(a). Just and reasonable rates are those that provide the utility an opportunity to earn a fair return on its property and are fair to the utility's customers. To this end, the North Carolina Supreme Court has counseled:

> [T]he fixing of "reasonable and just" rates involves a balancing of shareholder and consumer interests. The Commission must therefore set rates which will protect both the right of the public utility to earn a fair rate of return for its shareholders and ensure its financial integrity, while also protecting the right

> of the utility's intrastate customers to pay a retail rate which reasonably and fairly reflects the cost of service rendered on their behalf.

State ex rel. Utils. Comm'n v. Nantahala Power & Light Co., 313 N.C. 614, 691, 332 S.E.2d 397, 474 (1985), *rev'd on other grounds*, 476 U.S. 953, 90 L.Ed.2d 943 (1986), *appeal after remand*, 324 N.C. 478, 380 S.E.2d 112 (1989) (*Nantahala*).

The burden of proof to show that rates are just and reasonable is on the utility. N.C.G.S. § 62-134(c). However,

> the reasonableness and prudence of those costs is "presumed" unless the Commission or an intervenor adduces sufficient evidence to cast doubt upon their reasonableness or prudence, at which point the burden to make an affirmative showing of the reasonableness of the costs in question shifts to the utility. *State ex rel. Utils. Comm'n v. Intervenor Residents of Bent Creek/Mt. Carmel Subdivisions*, 305 N.C. 62, 76, 286 S.E.2d 770, 779 (1982) (*Bent Creek*). In order to satisfy this burden of production, an intervenor must offer affirmative evidence tending to show that the expenses that the utility seeks to recover "are exorbitant, unnecessary, wasteful, extravagant, or incurred in abuse of discretion or in bad faith or that such expenses exceed either the cost of the same or similar goods or services on the open market or the cost similar utilities pay to their affiliated [utilities] for the same or similar goods or services." *Id.* at 76–77, 286 S.E.2d at 779. If a utility expense is "properly challenged," "[t]he Commission has the *obligation* to test the reasonableness of such expenses." *Id*. at 76, 286 S.E.2d at 779.

Stein, 375 N.C. at 908, 851 S.E.2d at 261-62.

Finally, the Commission's orders must be based on competent, material, and substantial evidence in the record. N.C.G.S. § 62-65(a). Where settlement has been reached by less than all of the parties in a case, as with the CCR Settlement in these cases, that settlement should be accorded full consideration and weighed by the Commission along with all other evidence presented in reaching its decision:

> The Commission may even adopt the recommendations or provisions of the nonunanimous stipulation as long as the Commission sets forth its reasoning and makes 'its own independent conclusion' supported by substantial evidence on the record that the proposal is just and reasonable to all parties in light of all the evidence presented.

State ex rel. Utils. Comm'n v. Carolina Util. Customers Ass'n, Inc., 348 N.C. 452, 466, 500 S.E.2d 693, 703 (1998) (*CUCA I*); *see also State ex rel. Utils. Comm'n v. Carolina Util. Customers Ass'n, Inc.*, 351 N.C. 223, 524 S.E.2d 10 (2000) (*CUCA II*).

Discussion and Conclusions

In summary, based upon the evidence and the whole record, including the provisions of the CCR Settlement applicable to these dockets, and in the exercise of its independent judgment and discretion after considering all material facts of record, the Commission concludes that the CCR Settlement is in the public interest and should be approved. Moreover, the Commission concludes that the ratemaking treatment of CCR costs set forth in the CCR Settlement results in just and reasonable rates for the Companies' customers. As provided in the CCR Settlement, the Commission leaves in place the decision on CCR cost recovery in the Subs 1142 and 1146 proceedings, including the Cost of Service Penalties.

The issues related to the recovery of costs incurred to comply with CAMA and the CCR Rule have been highly contentious in the last two general rate cases for both DEP and DEC. The parties to the instant proceedings proffered several hundreds of pages and hours of testimony reviewing the history of coal-fired generation and the handling of coal ash throughout the history of the utilities serving North Carolina consumers, comparing the past coal ash handling practices of these utilities to others across the region and the country, debating what different decisions perhaps should have been made and when, and attempting to quantify the impact of such decisions on the CCR costs now sought to be recovered from customers. Additionally, the Commission has received significant testimony from public witnesses on these issues. Indeed, coal ash — including its environmental impact and associated cost — was the predominant topic at the public witness hearings held in these 2017, as well as the 2019, rate cases.

As noted above, and prior to its joining the CCR Settlement, the Public Staff had argued that responsibility for these costs (not otherwise imprudently incurred) should be shared equally between the utility and its customers. Other parties argued that the utility should bear all or substantially all of the costs of compliance with the recently adopted state and federal requirements. After careful consideration, the Commission in the 2018 DEP and DEC Rate Orders determined that the CCR costs incurred, with one exception, were reasonable and prudent but imposed a management penalty in each case.

Subsequent to issuance of the *Stein* opinion on December 11, 2020, the CCR Settling Parties worked to reach a compromise on the issues. The CCR Settlement seeks to resolve not only the 2017 rate cases on remand from the Court but also the 2019 rate cases and future CCR costs to be incurred through January 2030 for DEC and February 2030 for DEP.

On February 12, 2021, upon joint motion of the CCR Settling Parties, as well as CIGFUR II and CIGFUR III, the Commission reopened the evidentiary records; accepted into evidence the CCR Settlement and the supporting testimony filed by DEC, DEP, and the Public Staff; allowed additional testimony or comments on the CCR Settlement by other parties; and allowed requests for hearing by any party. No additional testimony or comments were filed by any party, and no party requested a hearing. Thus, all parties waived their rights to introduce additional testimony or to cross-examine DEP's, DEC's, or the Public Staff's witnesses on their settlement testimony.

The Commission recognizes that the CCR Settlement is the product of give-and-take between the CCR Settling Parties — DEP, DEC, the AGO, Sierra Club, and the Public Staff. The settlement and supporting testimony by the parties offer an immediate and longer-term resolution of the ratemaking treatment of CCR costs in lieu of the positions previously advocated by the parties. The settlement aimed to resolve these contentious issues in the outstanding DEP and DEC rate cases, as well as into the near future, and strikes a balance between the Companies and their customers that each of the CCR Settling Parties found to be appropriate and in the public interest.

The Companies explain that the CCR Settlement provides benefit to customers through both immediate and future rate reduction — DEP and DEC together will absorb approximately $1.1 billion (on a North Carolina system basis) in CCR-related costs over the time period covered by the CCR Settlement, reducing the amounts they would otherwise seek to recover from customers. On a North Carolina retail basis, the net present value of the savings to customers from forgone CCR cost recovery (including applicable financing costs) amounts to more than $900 million. Importantly, a large portion of the rate reduction will occur over the near term, during a period in which many customers are suffering severe economic hardship from the COVID-19 pandemic. The Commission takes note that the Public Staff supports this position, asserting that the settlement obligates DEP and DEC to forego recovery of costs in excess of $900 million (combined DEP and DEC), resulting in a significant reduction in the proposed revenue increase in this case.

The Commission recognizes that for purposes of these proceedings the CCR Settling Parties agreed that the Commission should leave in place its decisions in the Subs 1142 and 1146 proceedings, including the Cost of Service Penalties. The agreement to these provisions was made in conjunction with the agreement as to additional reductions to the Companies' CCR cost recovery of $261 million (DEP) and $224 million (DEC) in the 2019 rate cases, future reduced recovery of CCR costs through January/February 2030 of $162 million (DEP) and $108 million (DEC), and other additional customer-savings provisions. Finally, the Commission notes that the Intervenor Settling Parties have agreed to waive their rights to assert that Future CCR Costs, including Financing Costs, shall be shared between the Companies and customers through equitable sharing or any other adjustment for the purpose of sharing, and waive their rights to challenge any Future CCR Costs, including Financing Costs on the basis that the Companies' historical coal ash management practices were inadequate and led to unreasonable CCR costs being incurred or led to CCR costs being unreasonably higher than otherwise would have been incurred. The Intervenor Settling Parties reserve their rights only to propose a disallowance adjustment to future CCR costs on the grounds that the costs were otherwise unreasonable or were imprudently incurred.

Thus, the CCR Settling Parties have settled the ratemaking treatment of CCR costs in these rate cases, the 2019 rate cases, and future rate cases. The settlement aims to reduce costs that are passed on to customers, to avoid additional protracted litigation over the Companies' historical management practices, and to provide some closure to the debate that has been waged for several years. Indeed, as noted above, the parties to the Companies' rate cases have extensively litigated these contested issues since at least the filing of the 2017 rate cases, and the CCR Settlement seeks to resolve comprehensively certain issues for CCR costs incurred by DEP from January 1, 2015, through February 28, 2030, and by DEC from January 1, 2015, through January 31, 2030.

While the CCR Settlement is a nonunanimous settlement, the Commission places significant weight on the fact that the Public Staff and the AGO, each of which has litigated the issues associated with CCR cost recovery vigorously in these cases and advocated zealously for consumers, are parties to the CCR Settlement. Moreover, beginning with the 2017 rate cases, each of the CCR Settling Parties has advocated for significantly different ratemaking treatment for CCR costs, particularly as to how much cost should be borne by customers versus by the Companies. Thus, the Commission recognizes the extent of the compromise and give-and-take that was necessary to achieve consensus on the ratemaking issues.

As noted by Public Staff witness Maness,

> among the most important benefits provided by the CCR Settlement Agreement are: (1) the agreement of DEC and DEP to forego recovery of CCR Costs and associated Financing Costs in excess of $900 million (combined DEC and DEP), on a present value basis, over the period from January 1, 2015, through January 31, 2030 (DEC), and February 28, 2030 (DEP), resulting in a significant reduction in the proposed revenue increase in this case; (2) the agreement to allocate any proceeds of CCR insurance litigation; and (3) the avoidance of protracted litigation over CCR and Financing Costs into 2030 among the parties to the Agreement and possibly the appellate courts.

Maness Settlement Testimony at 5-6. For these reasons, the Public Staff concludes that the CCR Settlement is in the public interest and should be approved.

Similarly, as noted by the Companies' witness De May, the settlement "represents a balanced solution" that provides both immediate and long-term savings for customers while providing the certainty the Companies require to meet their business needs. Further, witness De May explains that the settlement allows the CCR Settling Parties to put the debate behind them and move forward to focus on a cleaner energy future.

CUCA is the one party to these proceedings that presented evidence regarding DEP's and DEC's CCR costs but did not join the CCR Settlement.[2] CUCA witness

[2] The Commission notes that CUCA is indicated as "not objecting" to the CCR Settlement and did not request an opportunity to present additional evidence on the CCR Settlement or cross-examine the witnesses of the Companies or the Public Staff on the CCR Settlement.

O'Donnell testified that the North Carolina legislature passed CAMA in 2014 in response to the Dan River spill and that CAMA is more stringent than the CCR Rule. He recommended that DEP not be allowed to recover CCR costs associated with any plant that is not subject to the CCR Rule but that is subject to CAMA. He further recommended that to the extent any site was no longer receiving coal ash, remediation costs should not be paid for by ratepayers in these cases or any future cases. These arguments were previously rejected in both the 2018 DEP and DEC Rate Orders, and these Commission determinations were upheld by the North Carolina Supreme Court in *Stein*. Further, the Commission notes that the Commission's adoption of the CCR Settlement provides CUCA some relief in that the Companies have agreed to reduce a combination of CCR Costs and Financing Costs sought to be recovered in the 2019 rate cases as well as certain amount of Future CCR Costs in the next general rate case for each Company.

After several years of litigation before this body and the North Carolina Supreme Court, the CCR Settling Parties have worked to achieve a settlement of their views and what they perceive to be a full and fair resolution of their disparate positions. In recognition of the foregoing, and based on the evidence in the record, the Commission is persuaded that the compromise on the ratemaking treatment of CCR costs embodied in the CCR Settlement reasonably balances the interests of the utilities and the ratepayers and will result in just and reasonable rates for ratepayers. The CCR Settlement appropriately resolves the issues involving the ratemaking treatment of the costs incurred in connection with DEP's and DEC's management, handling, and remediation of CCRs, including the Financing Costs incurred while those costs are deferred and while they are being recovered through the Amortization Period. In addition, the CCR Settlement provides benefits to customers, including a significant reduction in the amount of costs to be recovered by the Companies, certainty as to the application of insurance proceeds for customers' benefit, and the avoidance of protracted and expensive litigation regarding the Companies' historical practices. The CCR Settlement, which provides significant savings to customers in the near term, also appropriately balances the need for rate relief with the impact of such rate relief on customers in light of the current economic conditions faced by customers due to the COVID-19 pandemic.

The Commission also acknowledges the public witness hearings conducted by the Commission in these proceedings, as well as in the 2019 rate cases, during which public witnesses appeared and testified before the Commission. A majority of those witnesses who testified expressed concerns regarding the costs and impacts of coal-fired electricity generation, and the Commissioners heard first-hand the many perspectives and opinions of customers as to the clean-up of coal ash and the associated costs. Similarly, numerous statements of consumer position filed in these dockets expressed that customers should not bear responsibility for costs associated with the clean-up of coal ash. Thus, based on the perspectives and concerns consistently expressed by witnesses at the public hearings and in the statements of consumer position, the Commission concludes that the history and legacy of coal-fired electricity generation by the Companies is an issue of significant importance to their customers, and their perspectives have been given weight in the Commission's decision-making process. While the CCR Settlement may not go as far as many, but not all, customers advocated, it strikes a fair balance for customers that the

Commission determines will reduce costs (and rates) associated with CCRs, particularly in the near term, and furthers the Companies' financial health and access to capital at a reasonable cost for the customers' benefit.

For these reasons, and based on its determination that the ratemaking treatment set forth by the Settling Parties in the CCR Settlement will result in just and reasonable rates for DEP's and DEC's customers and will comprehensively resolve the CCR cost recovery issues litigated in the 2017 and 2019 rate cases, the Commission concludes that the CCR Settlement is in the public interest and should be approved on remand. In reaching this conclusion, the Commission has carefully considered the direction given by the Court and further concludes that approval of the CCR Settlement is not inconsistent with, and satisfies, the Court's decision in *Stein*.

IT IS, THEREFORE, ORDERED as follows:

1. That the CCR Settlement is hereby approved, and the results of the Commission's ratemaking decisions in the Docket No. E-2, Sub 1142 and E-7, Sub 1146 proceedings, including the management penalties, remain in place and unchanged; and

2. That the approval of the CCR Settlement resolves the issues remanded to the Commission by the North Carolina Supreme Court in *Stein* and concludes the proceedings on remand.

ISSUED BY ORDER OF THE COMMISSION.

This the 25th day of June, 2021.

NORTH CAROLINA UTILITIES COMMISSION

Joann R. Snyder

Joann R. Snyder, Deputy Clerk

Commissioner Daniel G. Clodfelter concurs in the result.

DOCKET NO. E-2, SUB 1142
DOCKET NO. E-7, SUB 1146

Commissioner Daniel G. Clodfelter, concurring in the result:

Although I do not join in the Commission majority's opinion, for the reasons set forth in my partial dissenting opinions in Docket Nos. E-2, Sub 1219 and E-7, Sub 1214, and subject to the limitations and qualifications contained in those opinions, I concur in the result.

/s/ Daniel G. Clodfelter
Commissioner Daniel G. Clodfelter

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

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

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219 In the Matter of Application by Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina DOCKET NO. E-2, SUB 1193 In the Matter of Application of Duke Energy Progress, LLC, for an Accounting Order to Defer Incremental Storm Damage Expenses Incurred as a Result of Hurricanes Florence and Michael and Winter Storm Diego	ORDER ACCEPTING STIPULATIONS, GRANTING PARTIAL RATE INCREASE, AND REQUIRING CUSTOMER NOTICE

HEARD: Thursday, February 27, 2020, at 7:00 p.m., in the Jury Assembly Room, 3rd Floor, Richmond County Judicial Center, 105 West Franklin Street, Rockingham, North Carolina

Monday, March 2, 2020, at 7:00 p.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

Tuesday, March 3, 2020, at 7:00 p.m., in the New Hanover County Courthouse, Courtroom 317, 316 Princess Street, Wilmington, North Carolina

Wednesday, March 4, 2020, at 7:00 p.m., in the Greene County Courthouse, 301 North Greene Street, Snow Hill, North Carolina

Thursday, March 12, 2020, at 7:00 p.m., in Courtroom 1A, Buncombe County Court, 60 Court Plaza, Asheville, North Carolina

Monday, August 24, 2020, at 2:00 p.m., held via video conference and reconvened on Tuesday, September 29, 2020, at 9:00 a.m., via video conference

BEFORE Commissioner Daniel G. Clodfelter, Presiding; Chair Charlotte A. Mitchell; and Commissioners ToNola D. Brown-Bland; Lyons Gray; Kimberly W. Duffley; Jeffrey A. Hughes, and Floyd B. McKissick, Jr.

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For the Commercial Group:

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[1] On January 12, 2021, the Commission issued an Order granting the motion of Mr. Page, and Marcus W. Trathen and Craig D. Schauer — of Brooks, Pierce, McLendon, Humphrey & Leonard, LLP — to allow Mr. Page to withdraw and to substitute Mr. Trathen and Mr. Schauer as counsel for CUCA.

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Teresa Townsend, Special Deputy Attorney General, and Margaret A. Force, Assistant Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27603

[2] On February 22, 2021, the Commission issued an Order granting the motion of Mr. Culley and Harry Carl Johnson to allow Mr. Culley to withdraw and to substitute Mr. Johnson as counsel for Vote Solar.

INDEX TO SUBSTANTIVE ISSUES

BY THE COMMISSION: On September 30, 2019, pursuant to Commission Rule R1-17(a), Duke Energy Progress, LLC (DEP or Company), filed notice of its intent to file a general rate case application.

On October 30, 2019, the Company filed its Application to Adjust Retail Rates and Request for an Accounting Order (the Application), along with a Rate Case Information Report Commission Form E-1 (Form E-1), and the direct testimony and exhibits of numerous witnesses.

PROCEDURAL HISTORY AND JURISDICTION

Procedural History

The Commission has issued a multitude of procedural orders in these dockets, all of which are a matter of record herein. The following is a summary of the most pertinent filings by DEP and the parties and the Commission's procedural orders.

On various dates, petitions to intervene were filed by the following parties and were granted by orders of the Commission: CIGFUR, CUCA, Commercial Group, FPWC, Harris Teeter, Hornwood, NC WARN, NCSEA, NCCEBA, NCJC et al., NCLM, Sierra Club, Vote Solar, and the Dept. of Defense. In addition, a Notice of Intervention was filed by the North Carolina Attorney General's Office (AGO). The Public Staff's intervention is recognized pursuant to N.C. Gen. Stat. § 62-15(d) and Commission Rule R1-19.

On November 14, 2019, the Commission issued its Order Establishing General Rate Case and Suspending Rates. On December 6, 2019, the Commission issued its Order Scheduling Investigation and Hearings, Establishing Intervention and Testimony Due Dates and Discovery Guidelines, and Requiring Public Notice (Scheduling Order).

The expert witness hearing in this matter was initially set to commence on May 4, 2020. However, due to the novel coronavirus pandemic (COVID-19) and the State of Emergency declared by Governor Roy Cooper, on April 3, 2020, the Company filed a Motion for an Order Addressing Procedural Issues. As part of the motion, DEP acknowledged that one complicating factor was the potential running of the 270-day suspension period specified in the Commission's November 14, 2020 Order and the potential mandatory placement of DEP's proposed rates into effect under N.C.G.S. § 62-134(b). Therefore, subject to its right to implement temporary rates under N.C.G.S. § 62-135, DEP asked the Commission to issue an order acknowledging and accepting DEP's notice of the prospective waiver through December 31, 2020, of its right to seek to implement its original proposed rates in this proceeding by operation of N.C.G.S. § 62-134(b) in the event that the postponement sought rendered the issuance of a Commission determination on just and reasonable rates in this proceeding prior to the end of the suspension period infeasible.

In February and March 2020, the Commission held five public hearings as scheduled by the Scheduling Order for the purpose of receiving the testimony of public witnesses.

On April 7, 2020, the Commission issued its Order Addressing Procedural Matters providing for revised testimony filing deadlines and discovery guidelines for the Company's rebuttal testimony.

On April 13, 2020, the Public Staff and numerous other parties filed the direct testimony and exhibits of their witnesses. On April 23, 2020, the Public Staff filed the supplemental testimony of several witnesses.

On May 4, 2020, DEP filed the rebuttal testimony and exhibits of several witnesses.

On May 6, 2020, DEP, its affiliate Duke Energy Carolinas, LLC (DEC) (collectively the Companies), and the Public Staff filed a motion to consolidate for hearing DEP's Application and DEC's Application to Adjust Retail Rates and Request for an Accounting Order in Docket No. E-7, Sub 1214 (DEC Application). Their motion stated that many of the issues in the two rate cases were based on substantially similar testimony and that efficiencies could be gained by consolidating the expert witness hearings for the Companies.

On May 29, 2020, the Commission issued an Order Proposing Procedures for Partially Consolidated Expert Witness Hearing, Scheduling Pre-Hearing Conference. The order revised the schedule for the DEP expert witness hearing and consolidated the DEP hearing with the expert witness hearing in the DEC Application on topics to be later identified.

On June 2, 2020, DEP and the Public Staff entered into and filed an Agreement and Stipulation of Partial Settlement (First Partial Stipulation) settling some issues in the case. That same day, the Company filed settlement testimony of witness De May and settlement testimony and exhibits of witness Smith.

On June 5, 2020, a pre-hearing conference was held. By subsequent orders, the Commission scheduled a consolidated DEC and DEP expert witness hearing on several topics, with the hearing to be held remotely by video conference.

On June 8, 2020, DEP and Harris Teeter entered into and filed a Settlement Agreement (Harris Teeter Stipulation or HT Stipulation).

On June 9, 2020, DEP and the Commercial Group entered into and filed a Settlement Agreement (Commercial Group Stipulation or CG Stipulation).

On June 22, 2020, DEP filed a Petition for An Accounting Order to Defer Impacts of Its Suspended Rate Case In Lieu of Implementing Temporary Rates Under Bond requesting to defer the revenue impacts of the postponement of the expert witness hearing.

On June 26, 2020, DEP and CIGFUR entered into and filed an Agreement and Stipulation of Settlement (CIGFUR Stipulation).

On July 9, 2020, DEP filed an Agreement and Stipulation of Settlement with Vote Solar (Vote Solar Stipulation).

On July 10, 2020, the Commission issued an order denying DEP's Petition for Accounting Order.

On July 23, 2020, DEP, NCSEA, and NCJC et al. entered into and filed an Agreement and Stipulation of Settlement (NCSEA/NCJC et al. Stipulation).

On July 31, 2020, DEP and the Public Staff entered into and filed a Second Agreement and Stipulation of Partial Settlement (Second Partial Stipulation, collectively with the First Partial Stipulation, the Public Staff Partial Stipulations) settling additional issues in the case. That same day and in support of the Second Partial Stipulation, the Public Staff filed the testimony of witnesses Maness, McLawhorn, and Woolridge, and the Company filed the testimony of witnesses De May, D'Ascendis, Smith, and Newlin.

On various dates in August 2020, the Company filed amendments to the Commercial Group, Vote Solar, CIGFUR, Harris Teeter, and NCSEA/NCJC et al. Stipulations, whereby the parties agreed that if the Commission enters a final order in this docket approving a 9.60% ROE based on a 52% equity and 48% long-term debt capital structure then certain provisions of each of their respective stipulations would be deemed fulfilled.

On August 7, 2020, DEP filed its Motion for Approval of Notice Required by N.C.G.S. § 62-135 to Implement Temporary Rates, Subject to Refund, and Authorization of EDIT Riders and Motion for Approval of Undertaking Required by N.C.G.S. § 62-135 to Implement Temporary Rates, Subject to Refund.

On August 10, 2020, the Commission issued its Order Rescheduling Separate Expert Witness Hearings to be Conducted Remotely.

On August 11, 2020, the Commission entered an Order Consolidating Dockets, consolidating the rate case and the Company's Application for an Accounting Order to Defer Incremental Storm Damage Expenses Incurred as a Result of Hurricanes Florence and Michael and Winter Storm Diego in Docket No. E-2, Sub 1193.

Also on August 11, 2020, the Commission issued its Order Approving Public Notice of Interim Rates Subject to Refund and Financial Undertaking.

On August 24, 2020, the matter came on for the consolidated expert witness hearing. Testimony and exhibits were presented for DEC, DEP, and several parties on financial issues, including cost of capital, capital structure and credit quality, as well as Excess Deferred Income Taxes (EDIT), the Companies' proposed Grid Improvement Plan, and rate affordability. The DEP-specific expert witness hearing commenced on September 29, 2020, and DEP and the parties presented testimony and exhibits on numerous additional issues specific to DEP.

On December 4, 2020, several parties submitted post-hearing briefs and proposed orders.

On January 25, 2021, DEP, DEC, the Public Staff, AGO, and Sierra Club (collectively, CCR Settling Parties) filed a Coal Combustion Residuals Settlement Agreement (CCR Settlement) in the instant dockets and in Docket Nos. E-2, Sub 1142, E-7, Sub 1146, and E-7, Sub 1214 (rate case dockets).

On January 29, 2021, CCR Settling Parties filed a joint motion requesting that the Commission reopen the rate case dockets, consolidate consideration of the CCR Settlement in the dockets with its further consideration of issues remanded to the Commission by the North Carolina Supreme Court in *State ex rel. Utils. Comm'n v. Stein,* 375 N.C. 870, 851 S.E.2d 237 (2020) (*Stein*), admit the CCR Settlement and supporting testimony into evidence, and approve the CCR Settlement, reflecting that approval in its decisions in the rate case dockets, as well as in its order(s) on remand in response to the *Stein* decision.

On February 1, 2021, DEC and DEP filed testimony and exhibits in support of the CCR Settlement, and on February 5, 2021, the Public Staff filed testimony and exhibits in support of the CCR Settlement.

On February 12, 2021, the Commission issued an order reopening the rate case dockets, accepting into evidence the CCR Settlement and supporting testimony, allowing parties to file testimony or comments on the CCR Settlement, and allowing parties to file a request for a hearing on the CCR Settlement and supporting testimony.

Jurisdiction

No party has contested the fact that DEP is a public utility subject to the Commission's jurisdiction pursuant to the Public Utilities Act (Act), Chapter 62 of the North Carolina General Statutes. The Commission concludes that it has personal jurisdiction over DEP and subject matter jurisdiction over the matters presented in DEP's Application.

Application

In summary, DEP requested in its Application and initial direct testimony and exhibits a base rate increase of approximately $585.9 million, or 15.6%, in its annual electric sales, offset by a rate reduction of $120.2 million to refund certain tax benefits and $2.1 million related to the proposed Regulatory Asset and Liability Rider, for a net revenue increase of $463.6 million, or 12.3% from its North Carolina retail electric operations, including an ROE of 10.30% and a capital structure consisting of 47% debt and 53% equity.

DEP submitted evidence in this case with respect to revenue, expenses, and rate base using a test period consisting of the 12 months ended December 31, 2018, adjusted for certain known changes in revenue, expenses, and rate base.

DEP, by its Second Settlement Testimony and Exhibits, revised its requested base revenue requirement increase to $408,933,000 to incorporate the Company's adjustments filed in its Second Settlement Testimony and Exhibits filing and the Company's Second Supplemental Testimony and Exhibits filing, offset by a rate increase of $7,381,000 for the Revised Annual EDIT Rider 1 and reduction of ($152,348,000) for the Annual EDIT Rider 2 to refund certain tax benefits, and ($2,091,000) for the Regulatory Asset and Liability Rider, for a net revenue increase of $261,875,000.

Whole Record

The Commission held public witness hearings as noted above. The following public witnesses appeared and testified:

Rockingham: No public witnesses appeared.

Raleigh: Joe Adamsky, Lib Hutchby, April Springer, Ananya Seelam, Christopher Thompson, Hwa Huang, Bob Rodriguez, Steve Hahn, Kay Reibold, Jean-Luc Duvall, Mary Black, Beverly Moriarty, Barbara Cain, Sarah Macleod Owens, Carolyn Guckert, and Eleanor Weston

Wilmington: Herb Harton, George Vlasits, Clarice Reber, Beth Hansen, Jimmie Davis, Dwight Willis, Roberta Buckles, Shelli Sordellini, Priss Endo, Peter Perschbacher, Tim Holder, Deborah Dicks-Maxwell, Adair Wright, and Harper Peterson

Snow Hill: Bobby Jones, Lorrine Washington, Antonio Blow, Kristiann Hering, and Benjamin Lanier

Asheville: Roger Hollis, Viola Williams, Ben Scales, Stephanie Biziewski, Amanda Strawderman, Cody Kelly, Amanda Seta, Dr. Steven Norris, Cathy Holt, Jeff Jones, Phillip Bisesi, Padma Dyvine, David Saulsbury, Max Mandler, Sonny Charles Rawls, Chloe Moore, Judy Mattox, Ken Brame, Alex Lines, Melanie Noyes Debbie Resnick, Kim Roney, and Kenneth Bradley Lenz

In summary, almost all the public witnesses stated their opposition to DEP's proposed rate increase. *See generally*, tr. vols. 2-5. Many witnesses testified that they were on fixed incomes and about the poverty in some of the counties served by DEP. In addition, many public witnesses stated concerns about coal ash, including the health effects on people located in proximity to coal ash basins and contamination of water supplies. Further, witnesses expressed their view that it is unfair for the cost of the coal ash cleanup to burden ratepayers rather than coming out of the Company's or shareholders' profits. Moreover, public witnesses testified to their concern regarding DEP's use of fossil fuels, including coal and natural gas power plants, fracking, and DEP not adequately increasing the use of clean energy and renewables. Finally, some public witnesses voiced their view that DEP's executive compensation and shareholder dividends are excessive.

In addition to the public witness testimony, the Commission received numerous consumer statements of position, all of which were filed in the docket. *See generally*, Docket No. E-2, Sub 1219CS. The public witness testimony and consumer statements of position have been considered by the Commission in its deliberations on DEP's rate case Application.

In the Scheduling Order the Commission, without objection from any party, took judicial notice pursuant to N.C.G.S. § 62-65 of all evidence, decisions and matters of record on the issues of coal ash remediation, Power Forward, and advanced metering infrastructure (AMI), in DEP's last general rate case in Docket No. E-2, Sub 1142 (Sub 1142).[1] Said evidence, decisions and matters of record are hereby accepted into evidence in the present docket and incorporated by reference into this Order. The judicially noticed evidence will not be repeated in full or summarized but portions of the testimony and exhibits are referenced throughout this Order.

The testimony and exhibits in this proceeding are voluminous. The Commission has carefully considered all the evidence and the record as a whole. However, the Commission has not attempted to recount every statement of every witness in this Order. Rather, the Commission has summarized the evidence that is in the record. Likewise, while the Commission has read and fully considered the parties' post-hearing briefs, it has not in this Order attempted expressly to summarize or discuss every contention advanced or authority cited in the briefs.

[1] In referring to the evidence from the 2018 DEP rate case the Commission will designate the transcript and exhibits as "2018 Tr." and "2018 Ex.," respectively.

Based upon the foregoing and the entire record in this proceeding the Commission makes the following

FINDINGS OF FACT

Stipulations

1. On June 2, 2020, DEP and the Public Staff entered into and filed the First Partial Stipulation resolving some of the issues between the two parties, and on July 31, 2020, the Public Staff and DEP entered into and filed the Second Partial Stipulation, resolving several additional issues.

2. On various dates during this proceeding, DEP entered into and filed stipulations, and amendments thereto, with Harris Teeter (HT Stipulation), the Commercial Group (Commercial Group Stipulation or CG Stipulation), CIGFUR (CIGFUR Stipulation), Vote Solar (Vote Solar Stipulation), and a joint stipulation with NCSEA and NCJC et al. (NCSEA/NCJC et al. Stipulation), resolving some of the issues in this proceeding between these parties.

3. The stipulations with the Public Staff, Harris Teeter, Commercial Group, CIGFUR, Vote Solar, and jointly with NCSEA and NCJC et al. are products of the give-and-take negotiations among the parties.

Base Fuel and Fuel-Related Cost Factors

4. Consistent with Section IV.O of the Second Partial Stipulation, the total base fuel and fuel-related cost factors, by customer class, represented by the sum of the (a) respective base fuel and fuel-related cost riders set in Docket No. E-2, Sub 1142, and (b) the annual non-EMF fuel and fuel-related cost riders, by customer class, approved by the Commission in Docket No. E-2, Sub 1250, are just and reasonable to all parties.

Depreciation Study

5. Use of a 10% contingency for future “unknowns” in the estimate of future terminal net salvage costs is reasonable.

6. Use of the Company’s proposed future net salvage for mass property Accounts 364, Poles, Towers and Fixtures, Account 366, Underground Conduit and Account 369, Services is reasonable.

7. Use of an average service life of 15 years for the new advanced metering infrastructure (AMI) meters is reasonable.

8. The continued use of a 20-year amortization period for Accounts 391 and 397 is reasonable.

9. Except where specifically addressed in this Order, the depreciation rates proposed by DEP in this case, which are based on the Depreciation Study, filed by the Company as Spanos Direct Ex. 1, the Decommissioning Cost Estimate Study, and previously performed Burns and McDonnell decommissioning studies of each generating site, are just and reasonable.

Early Retirement of Coal Plants

10. The Company's integrated resource plan (IRP) proceeding is the appropriate venue for a thorough review of generating plant retirements.

11. The depreciation rates for the Mayo Unit 1 and Roxboro Units 3 and 4 generating plants should be based upon the remaining useful life of the plants.

Coal and Nuclear Fleet Investments

12. DEP's investments in its coal fleet were reasonably and prudently incurred to enable DEP to meet its obligation to provide safe, adequate, and reliable electric service.

13. It is not necessary or appropriate at this time to impose a limit on the DEP's future investments in its coal-fired generating assets.

14. The costs related to DEP's investments in its nuclear generation fleet were reasonably and prudently incurred.

CCR Cost Recovery

15. North Carolina enacted the Coal Ash Management Act (CAMA) in 2014, which was amended in 2016, and the United States Environmental Protection Agency (EPA) promulgated its final rule — the Coal Combustion Residuals Rule (CCR Rule) — in 2015. Together, these state and federal laws and regulations introduced new requirements for the management of coal ash, or coal combustion residuals (CCR), and mandate the closure of the coal ash basins at all of the Company's coal-fired power plants.

16. Since its last rate case, DEP has incurred significant additional costs to continue the closure and compliance efforts related to these federal and state legal requirements and its management and storage of CCR. On a North Carolina retail jurisdictional basis, as of August 31, 2020, the CCR costs DEP incurred for which it seeks recovery in this rate case amount to $440,115,029, $399,134,625 of which are the actual coal ash basin closure and compliance costs incurred by the Company during the period from September 1, 2017, through February 29, 2020, and the remaining $40,980,404 of which are the financing costs incurred by the Company upon the deferred costs through August 2020.

17. On January 25, 2021, DEP, DEC, the Public Staff, AGO, and Sierra Club (collectively, CCR Settling Parties) filed a Coal Combustion Residuals Settlement Agreement (CCR Settlement) in the instant dockets, in the DEC Rate Case dockets, and in the 2018 Rate Case dockets resolving the issues among the CCR Settling Parties related to CCR cost recovery.

18. The CCR Settlement, which is the product of the give-and-take in settlement negotiations between the CCR Settling Parties, is material evidence in this proceeding and is entitled to be given appropriate weight in this proceeding, along with other evidence adduced by the Company and intervenor parties.

19. Section III.E of the CCR Settlement provides that the amount of CCR costs and financing costs sought for recovery in this case will be reduced by $261 million. Additionally, Section III.E provides for the recovery of financing costs sought for recovery in this case during the deferral period, calculated at the weighted average cost of capital, as well as during a five-year amortization period, calculated using: (i) DEP's cost of debt as previously stipulated by the Company and the Public Staff in the Second Partial Stipulation adjusted as appropriate to reflect the deductibility of interest expense; (ii) a cost of equity 150 basis points below the 9.60% stipulated to in the Second Partial Stipulation; and (iii) a 48% debt and 52% equity capital structure.

20. Section III.F of the CCR Settlement provides that the amount to be recovered of CCR costs incurred by DEP from March 1, 2020, through February 28, 2030, along with associated financing costs incurred during the deferral period, will be reduced by $162 million but allows for recovery of any remaining CCR costs, subject to determination by the Commission that such costs were reasonably and prudently incurred. Additionally, Section III.F provides for recovery of financing costs during the applicable deferral period, calculated at the weighted average cost of capital, and permits recovery of financing costs during the applicable amortization period, calculated using a reduced cost of equity.

21. Section III.D.i of the CCR Settlement provides that the CCR Settling Parties waive their right to assert that future CCR costs should be shared between the Company and ratepayers through equitable sharing of the costs or other adjustment except as provided in the CCR Settlement. Section III.D.ii provides that the CCR Settling Parties waive their right to challenge future CCR costs on the basis that the Company's prior coal ash management practices were inadequate and led to unreasonable CCR costs being incurred or led to CCR costs being unreasonably higher than otherwise would have been incurred. Section III.D.iii of the CCR Settlement provides that the CCR Settling Parties reserve their right to propose an adjustment to future CCR costs on the grounds that the costs were otherwise unreasonable or were imprudently incurred.

22. Section III.G of the CCR Settlement provides for an allocation between DEP, DEC, and their customers of any proceeds from ongoing coal ash insurance litigation.

23. The provisions of the CCR Settlement are just and reasonable in light of all of the evidence presented. It is appropriate for the Company to reduce the balance of deferred CCR costs sought to be recovered in this rate case by $261 million. It is appropriate that the $261 million reduction reduce the deferred CCR costs as of December 31, 2020, and that DEP cease to accrue financing costs on that amount after December 31, 2020, and not seek to recover such financing costs from customers, as set forth in Section III.E of the CCR Settlement. After such reduction and updating financing costs through March 2021, the net amount for which the Company seeks recovery in this case is $191,577,737. It is further appropriate for the Company to defer CCR costs incurred since March 1, 2020, and to reduce the balance of deferred CCR costs sought to be recovered in its next general rate case by $162 million as set forth in Section III.F of the CCR Settlement. It is appropriate that no financing costs accrue on the $162 million as of December 31, 2020, as set forth in Section III.F of the CCR Settlement. The reduced financing costs agreed upon in Sections III.E and III.F of the CCR Settlement are appropriate.

ARO Accounting

24. DEP is required to comply with Generally Accepted Accounting Principles (GAAP), specifically, Accounting Standards Codification 410, Asset Retirement and Environmental Obligations (ASC 410) and Accounting Standards Codification 980, Regulated Operations (ASC 980).

25. DEP is required to comply with the Federal Energy Regulatory Commission's (FERC) Uniform System of Accounts (USOA), specifically, General Instruction No. 25, Accounting for Asset Retirement Obligations.

26. Neither GAAP nor FERC accounting rules determine the proper principles of cost recovery for North Carolina retail ratemaking purposes; rather, the ratemaking treatment determined by the Commission in accord with the provisions of Chapter 62 of the General Statutes determines how the Company should account for costs and revenues under the applicable GAAP and FERC rules.

Capital Structure, Cost of Capital, and Overall Rate of Return

27. As set forth in Section III.B of the Second Partial Stipulation, the Public Staff and the Company agreed on a capital structure consisting of 52% common equity and 48% long-term debt.

28. The Company's embedded cost of debt is 4.04%, as set forth in Section III.B of the Second Partial Stipulation.

29. The rate of return on common equity (ROE) that the Company should be allowed an opportunity to earn is 9.60%, as set forth in Section III.B of the Second Partial Stipulation.

30. The overall rate of return that the Company should be allowed the opportunity to earn on the cost of the Company's used and useful property is 6.93%, as set forth in Section III.B of the Second Partial Stipulation.

31. The overall rate of return and ROE are supported by competent, material, and substantial record evidence; are consistent with the requirements of N.C.G.S. § 62-133 in light of changing economic conditions; and appropriately balance the Company's need to maintain the safety, adequacy, and reliability of its service with the benefits received by DEP's customers from safe, adequate, and reliable electric service.

32. The capital structure, ROE, and overall rate of return set by this Order will result in just and reasonable rates.

Cost of Service Adjustments

33. The Public Staff First and Second Partial Stipulations provide for certain accounting adjustments upon which DEP and the Public Staff have agreed; the revenue requirement effects of the settled issues are outlined in Smith Partial Settlement Ex. 3, Smith Second Settlement Ex. 3, Maness Stipulation Ex. 1, Schedule 1, and Maness Second Stipulation Ex. 1, Schedule 1 (the Partial Stipulation Revenue Requirement Exhibits). These agreed-upon accounting adjustments are just and reasonable to all parties in light of all the evidence presented.

Deferral of Grid Improvement Plan Capital Costs

34. DEP requested deferral of the capital costs for approximately $988 million in Grid Improvement Plan (GIP) spending to occur from January 2020 through 2022.

35. As a result of DEP's Second Partial Stipulation with the Public Staff and settlements with other parties DEP narrowed the scope of the GIP programs for which the Company seeks capital cost deferral and reduced its request to approximately $400 million in GIP spending from June 2020 through 2022.

36. DEP's reduced GIP deferral request as set forth in the Second Partial Stipulation is reasonable and should be approved subject to limitation.

37. DEP has the burden of proving its GIP spending is reasonable and prudent when it seeks to recover, in any future proceeding, GIP costs from customers.

38. GIP expenditures beyond those covered by the GIP deferral approved herein are to be informed by the Integrated Systems and Operations Planning (ISOP) process.

39. DEP should file a proposal for moving all DSDR and CVR costs into base rates with its next general rate case application.

Regulatory Asset and Liability Rider

40. The Company's proposed Regulatory Asset and Liability rider (RAL-1), which refunds approximately $2.1 million to customers over a one-year period, is just and reasonable and consistent with the Commission's directive relating to the treatment of net over-amortizations of expired regulatory assets and liabilities since the Company's last general rate case.

Tax Act Issues

41. DEP's proposed revision to its previously approved North Carolina excess deferred income taxes (EDIT) rider (EDIT-1) to reflect the change in the federal corporate income tax rate from 35% to 21%, is just and reasonable and should be approved.

42. Federal protected EDIT should be removed from DEP's proposed rider and amortized through base rates in accordance with the Internal Revenue Service (IRS) normalization rules as DEP and the Public Staff agreed in their First Partial Stipulation.

43. The federal unprotected EDIT should be flowed back to customers using a levelized five-year rider as DEP and the Public Staff agreed in the Second Partial Stipulation.

44. The federal provisional revenues should be flowed back to customers using a levelized two-year rider as DEP and the Public Staff agreed in the Second Partial Stipulation.

45. State EDIT should be flowed back to customers using a levelized two-year rider as DEP and the Public Staff agreed in the Second Partial Stipulation.

46. The provisions of the CIGFUR Stipulation regarding the appropriate methodology to flow back unprotected EDIT and provisional revenues are not just and reasonable and should not be approved.

47. All federal unprotected EDIT and provisional revenues should be refunded to customers using the methodology based on the amounts each class paid and, specifically, as a credit by specific customer class divided by the adjusted class' test year sales, as recommended by Public Staff witness Floyd.

48. The agreement between DEP and the Public Staff outlined in the Second Partial Stipulation concerning how to address future changes in the federal corporate income tax rate or North Carolina state corporate income tax rate which may occur during the respective amortization periods is reasonable and appropriate.

Cost Allocation Methodology

49. In the Second Partial Stipulation DEP and the Public Staff agreed to calculate and allocate the Company's cost of service based on a Summer Coincident Peak (SCP) allocation methodology to determine the Company's North Carolina jurisdictional and retail customer class cost allocation and responsibility.

50. As set forth in the CIGFUR Stipulation, the Company has committed to file in its next general rate case the results of a class cost-of-service study with production and transmission costs allocated on the basis of the Summer/Winter Coincident Peak method and to consider such results for the sole purpose of apportionment of the change in revenue to the customer classes.

Rate Design

51. It is appropriate for the Company to conduct a comprehensive rate design study as DEP agreed to in the Second Partial Stipulation and expanded on in this Order.

Affordability

52. It is appropriate for the Company to convene a stakeholder process tasked with addressing affordability issues for low-income residential customers as DEP agreed in the NCSEA/NCJC et al. Stipulation and the Second Partial Stipulation.

53. It is appropriate for the Company to provide its share, in conjunction with the concurrent commitment of Duke Energy Carolinas, LLC, of an aggregate combined shareholder-funded contribution to the Helping Home Fund of $3 million per year for two years (for a total of $6 million) which will not affect rates, as DEP agreed in the NCSEA/NCJC et al. Stipulation.

54. It is appropriate for the Company to make an annual $2.5 million shareholder contribution to the Energy Neighbor Fund in 2021 and 2022 (for a total contribution of $5 million) which will not affect rates, as DEP agreed in the Second Partial Stipulation.

Storm Costs

55. DEP's costs of repairing the damage caused by Hurricanes Florence, Michael, Dorian, and Winter Storm Diego (Storm Costs), as presented by the Company in its Application and agreed to in the First Partial Stipulation are just and reasonable and were prudently incurred to the extent such costs represent actual amounts as of May 31, 2020. Any estimated costs as of that date or incurred afterward remain subject to review pursuant to the provisions of N.C.G.S. § 62-172(a)(16)(c).

56. DEP's Storm Costs total $714.0 million, consisting of approximately $567.3 million in actually incurred or projected storm response operations and

maintenance (O&M) costs, approximately $68.6 million in capital investments, and approximately $78.1 million in carrying costs calculated using the Company's approved weighted average cost of capital through August 31, 2020.

57. Consistent with the First Partial Stipulation and the testimony of witness De May, DEP has withdrawn these costs, including capital investments, from the current rate case, except regarding the prudence determination reached above.

58. It is appropriate that DEP continue to defer the Storm Costs in a regulatory asset account until the date storm recovery bonds are issued pursuant to an approved financing order in accordance with N.C.G.S. § 62-172 or until the Company seeks recovery of the Storm Costs through an alternative method of cost recovery.

59. It is appropriate that DEP continue to accrue and record carrying costs at the Company's approved weighted average cost of capital on the deferred balances in its storm cost recovery deferred account pending recovery through securitization, subject to the assumptions and conditions agreed to in the First Partial Stipulation.

60. A ten-year normalized adjustment to DEP's revenue request to account for anticipated storm expenses that are too small to securitize is appropriate for use in this proceeding.

61. It is appropriate to establish a Storm Cost Recovery Rider for the Company and to set the initial balance for that rider at $0 in conformance with the provisions of the First Partial Stipulation.

Service Regulations, Vegetation Management Reporting Obligations, and Quality of Service

62. The amendments to the service regulations proposed by the Company are reasonable and should be approved.

63. The Company shall file an annual report of its Vegetation Management performance similar to the DEC report format provided in Docket No. E-7, Subs 1146 and 1182.

64. The overall quality of electric service provided by DEP is good.

Advanced Metering Infrastructure and Green Button Connect

65. DEP's costs of deploying AMI meters were prudently incurred and are reasonable.

66. It is appropriate for DEP to recover Rider MRM costs not recovered from customers opting out of AMI meters from all DEP customers.

67. Whether DEP should implement Green Button "Connect My Data" should be addressed in the ongoing investigation and rulemaking in Docket No. E-100, Sub 161.

Focal Point Project Costs

68. The capital costs associated with Project Focal Point (Focal Point) should be removed from rate base.

Roxboro Wastewater Treatment Plant Deferral

69. DEP's request for an accounting order to establish a regulatory asset upon retirement of the Roxboro Wastewater Treatment Plant, at the time of the plant's anticipated early retirement in 2021, to defer the unrecovered remaining net book value of the plant and costs related to obsolete inventory, net of salvage, at the time of retirement is reasonable and is approved.

Accounting for Deferred Costs

70. The Company is authorized to receive a specific amount of revenue for each of the deferred costs approved by this Order. If DEP receives revenue for any deferred cost for a longer period of time than the amortization period approved by the Commission for that deferred cost, the Company should continue to record all revenue received for that deferred cost in the specific regulatory asset account established for that deferred cost until the Company's next general rate case.

Just and Reasonable Rates

71. The base non-fuel and base fuel revenues and rates approved herein are just and reasonable to the customers of DEP, to DEP, and to all parties to this proceeding, and serve the public interest.

Revenue Requirement

72. After giving effect to the portions of the settlement agreements approved herein and the Commission's decisions on contested issues, the annual revenue requirement for DEP will allow the Company a reasonable opportunity to recover its operating costs and earn the rate of return on its rate base that the Commission has found just and reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-3

Stipulations

The evidence supporting these findings of fact is found in the verified Application and Form E-1; the stipulations between DEP and other parties; the testimony and exhibits of DEP witness De May and Public Staff witness Maness; and the entire record in this proceeding.

Summary of the Evidence

Public Staff First and Second Partial Stipulations

On June 2, 2020, DEP and the Public Staff entered into and filed the First Partial Stipulation resolving some of the issues between the two parties, and on July 31, 2020, the Public Staff and DEP entered into and filed the Second Partial Stipulation, resolving several additional issues in this proceeding.

Witness De May explained that the First Partial Stipulation resolves several of the revenue requirement issues between the Company and the Public Staff. Tr. vol. 11, 782. Revenue requirement adjustments were agreed upon in the First Partial Stipulation for Storm Costs, Aviation, Executive Compensation, Board of Directors, Lobbying, Sponsorships & Donations, Rate Case Expenses, Outside Services, Severance, Incentive Compensation, the Asheville Combined Cycle (CC) project, W. Asheville Vanderbilt 115 kV project, Credit Card Fees, End of Life Nuclear Reserve, Protected Federal EDIT, and treatment of the CertainTEED payment obligation in this rate case. *Id.* at 783-84. These accounting and ratemaking adjustments and the resulting revenue requirement effect of the First Partial Stipulation are shown in Schedule 1 of Maness Stipulation Exhibit 1 and Smith Partial Settlement Ex. 3, which provide sufficient support for the annual revenue required on the issues agreed to in the First Partial Stipulation. The revenue requirement impact of the issues settled in the First Partial Stipulation is a reduction of the base revenue requirement of approximately $123,904,000 to $130,106,000, depending on the resolution of the Unresolved Issues.

The Second Partial Stipulation is based upon the same test period as the Company's Application, adjusted for certain known changes in revenue, expenses, and rate base through February 29, 2020 and May 31, 2020. The Second Partial Stipulation outlines the Unresolved Issues as follows: (1) cost recovery of the Company's coal ash costs, recovery amortization period and return during the amortization period; (2) the depreciation rates appropriate for use in this case, including the Company's proposal to shorten the lives of certain coal-fired generating facilities; and (3) any other revenue requirement or nonrevenue requirement issue other than those issues specifically addressed in this Second Partial Stipulation, the First Partial Stipulation, or agreed upon in the testimony of DEP and the Public Staff. Second Partial Stipulation, § II.

Witness De May testified that DEP and the Public Staff were able to reach the Second Partial Stipulation, which resolves most but not all of the remaining revenue requirement issues between DEP and the Public Staff. Tr. vol. 11, 789. Witness De May provided an overview of the major components of the Second Partial Stipulation, including an agreement regarding shareholder contributions to the Energy Neighbor Fund, cost of capital, return of state and federal EDIT to customers, deferral accounting treatment of certain GIP programs, cost of service methodology for this case, inclusion of the May

2020 Updates to certain pro forma adjustments subject to the Public Staff's audit of the updates and other terms concerning the May updates, the annual funding amount for the Company's Nuclear Decommissioning Trust Fund, and the amortization period for non-ARO environmental costs. *Id.* at 789-92.

In addition, witness De May outlined other areas of agreement, including terms governing the start date of the evidentiary hearings to allow time for the Public Staff to audit the May Updates, ongoing assessments of the cost effectiveness of GIP-related projects, clarification of GIP costs that are eligible for deferral, commitments to future cost of service studies, rate design issues, and commitments to conduct audits and reporting obligations regarding plant, materials and supplies inventory, vegetation management, and service reliability index reporting. *Id.* at 792. These accounting and ratemaking adjustments and the resulting revenue requirement effect of the Second Partial Stipulation are shown in Maness Second Stipulation Ex. 1, Schedule 1 and Smith Second Settlement Ex. 3, which provide sufficient support for the annual revenue required on the issues agreed to in the Second Partial Stipulation. The Company's calculation of the revenue requirement impact of the issues settled in the Second Partial Stipulation is an increase in the base revenue requirement of approximately $19,495,000, to be further adjusted by the Public Staff's recommendations in its testimony filed on September 15 and 16, 2020, and pending resolution of the Unresolved Issues.

Witness De May testified that he attended public hearings held by the Commission in this matter and personally heard from dozens of customers who are concerned about the impacts of any rate increase on their families and businesses and noted that the Company is very mindful of these concerns. *Id.* at 793. Witness De May stated that the concessions the Company has made in the Public Staff Partial Stipulations fairly balance the needs of DEP customers with the Company's need to recover investments made in order to continue to comply with regulatory requirements and safely provide high quality electric service to its customers, particularly so in the Second Partial Stipulation in light of the current economic conditions of many of the Company's customers due to the COVID-19 pandemic. *Id.*

Public Staff witness Maness testified that from the perspective of the Public Staff, the most important benefits provided by the Public Staff Partial Stipulations are: (a) an aggregate reduction in the Company's proposed revenue increase as to specific expense items agreed to by DEP and the Public Staff in this proceeding, and (b) the avoidance of protracted litigation between DEP and the Public Staff before the Commission and possibly the appellate courts. Tr. vol. 16, 35. Based on these ratepayer benefits, as well as the other provisions of the Public Staff Partial Stipulations, the Public Staff believes the Public Staff Partial Stipulations are in the public interest and should be approved. *Id*.

Section III of the First Partial Stipulation outlines a number of accounting adjustments to which DEP and the Public Staff have agreed as well as Section III.J of the Second Partial Stipulation. These accounting adjustments are fully discussed later in this Order.

Section IV of the Second Partial Stipulation outlines a number of aspects of the Company's record keeping and reporting practices to which DEP and the Public Staff have agreed.

CIGFUR Stipulation

On June 26, 2020, the Company and CIGFUR entered into and filed the CIGFUR Stipulation. No testimony supporting the settlement was filed.

As part of the CIGFUR Stipulation, DEP initially agreed that the revenues to be approved in this proceeding should be adjusted to provide the Company, through sound management, the opportunity to earn an ROE of 9.75% and that this ROE will be applied to the common equity component of the ratemaking capital structure consisting of 52% equity and 48% long-term debt. CIGFUR Stipulation, § II. Subsequently, on August 6, 2020, the Stipulation was amended to state that should the Commission approve an ROE of 9.60% applied to a capital structure of 52% equity, 48% debt, this section of the Stipulation should be deemed to be fulfilled.

In addition, CIGFUR agreed to support the Company's request for a deferral of GIP costs over three years. CIFGUR Stipulation, § III.A. Because the three-year GIP plan contains estimates, CIGFUR's support for the GIP deferral will be subject to a reservation of its rights to review and object to the reasonableness of specific project costs in future rate cases. To the extent that DEP enters into an agreement with other intervening parties agreeing to a cost cap or to otherwise limit the maximum allowed amount of the three-year GIP deferral, CIGFUR supports such cost containment measures.

Section III.B of the CIGFUR Stipulation provides that in the next rate case, DEP will propose to allocate the deferred GIP costs among classes, consistent with its distribution cost allocation methodologies proposed in this docket, including use of the minimum system method (MSM) and voltage differentiated allocation factors for distribution plant. Additionally, with Commission approval, the Company will use this methodology to allocate GIP costs during the three years for which it may seek recovery in future rate cases.

Under Section IV, the parties agreed to refund unprotected EDIT on a uniform cents per kilowatt-hour (cents/kWh) basis.

Under Section V, DEP and CIGFUR agreed to five conditions related to cost of service and rate design. The first condition would obligate DEP to discuss and consider potential cost of service methodologies and to consider the results of a cost of service study based on the Summer/Winter Coincident Peak method. The second condition would require DEP in its next rate case to adjust peak demand to remove curtailable/non-firm load, even when the load reduction is not requested. The third condition would require DEP in its next two fuel proceedings to propose the uniform percentage average bill adjustment methodology. The fourth condition would require DEP in its next three rate cases to allocate distribution expenses using the MSM unless the Commission rejects the method. In the fifth, and final condition, the Company agreed to explore certain rate designs and file the rates if there was interest from CIGFUR customers.

Harris Teeter/Commercial Group Stipulations

On June 8, 2020, DEP and Harris Teeter entered into and filed the HT Stipulation, and on June 9, 2020, DEP and the Commercial Group entered into and filed the CG Stipulation. These settlements are substantially similar, and they resolve several issues between DEP and these parties, among other things, ROE and capital structure, GIP, and some rate design issues. No testimony supporting either settlement was filed.

As part of these stipulations DEP initially agreed that the revenues to be approved in this proceeding should be adjusted to provide the Company, through sound management, the opportunity to earn an ROE of 9.75% and that this ROE will be applied to the common equity component of the ratemaking capital structure consisting of 52% equity and 48% long-term debt. CG Stipulation, § 5; HT Stipulation, § 5. Subsequently, both stipulations were amended to state that should the Commission approve an ROE of 9.60% applied to a capital structure of 52% equity, 48% debt, Paragraph 5 of each Stipulation should be deemed to be fulfilled.

As part of its stipulation with DEP the Commercial Group neither opposes nor specifically supports the approval of the Company's requested GIP deferral. CG Stipulation, § 1. Harris Teeter supports the approval of the Company's requested GIP deferral with certain conditions detailed therein, including a reservation of Harris Teeter's right to take any position as to the reasonableness of specific GIP costs in a future rate case. HT Stipulation, § 1.

Further, DEP, Commercial Group, and Harris Teeter agreed that any GIP costs allocated to SGS-TOU customers shall be recovered via SGS-TOU demand charges. They also agreed that the percentage base rate increase for Rate Schedule SGS-TOU and Rate Schedule MGS shall be the same, while acknowledging that DEP shall have the right to adjust the rates for Rate Schedule CSE and Rate Schedule CSG more than the percentage base rate increase for Rate Schedule MOS. CG Stipulation, § 3; HT Stipulation, § 3. In addition, the settlements provide that the SGS-TOU on-peak and off-peak energy demand changes shall be increased by a percentage that is no greater than half of the approved overall increase percentage for the SGS-TOU rate schedule, but that the demand charges shall be adjusted by the amount necessary to recover the final SGS-TOU revenue target. CG Stipulation, § 4; HT Stipulation, § 4.

NCSEA/NCJC et al. Stipulation

On July 23, 2020, DEP and NCSEA and NCJC et al. entered into and filed the NCSEA/NCJC et al. Stipulation, resolving some of the issues in this proceeding between these parties. No testimony supporting the settlement was filed.

As part of the NCSEA/NCJC et al. Stipulation, the parties initially agreed that the revenues to be approved in this proceeding should be adjusted to provide the Company, through sound management, the opportunity to earn an ROE of 9.75% and that this ROE will be applied to the common equity component of the ratemaking capital structure consisting of 52% equity and 48% long-term debt. NCSEA/NCJC et al. Stipulation, § II. Subsequently, on August 10, 2020, the parties filed an amendment to their stipulation providing that should the Commission approve an ROE of 9.60% applied to a capital structure of 52% equity, 48% debt, Paragraph II of the Stipulation should be deemed to be fulfilled.

NCSEA/NCJC et al. also agreed to support the Company's request for an accounting order for approval to defer GIP costs for investments in Integrated System Operations Planning (ISOP), Integrated Volt Var Control (IVVC), Self-Optimizing Grid (SOG), Distribution Automation, Transmission System Intelligence, the Distributed Energy Resources (DER) Dispatch Tool, and the 44 kilovolt Line Rebuild. NCSEA/NCJC et al. believe that these investments will directly enable and support the greater utilization of DERs on the Company's system. For all other GIP investments proposed by DEP, NCSEA/NCJC et al. do not oppose the requested deferral accounting treatment. To the extent that DEP enters into an agreement with other intervening parties agreeing to a cost cap or to limit the amount of any GIP investment category specified for deferral treatment, NCSEA/NCJC et al. support such cost containment measures, but subject to a reservation of their rights to review and object to the reasonableness of specific project costs in future rate cases.

Pursuant to other provisions of the NCSEA/NCJC et al. Stipulation DEP agreed:

(1) to provide, in conjunction with the concurrent commitment of Duke Energy Carolinas, LLC (DEC), an aggregate combined shareholder-funded contribution to the Helping Home Fund of $3 million per year for two years (for a total of $6 million);

(2) that within six months of the effective date of the Stipulation, in addition to the low-income collaborative proposed by DEP, the parties agreed to collaborate to design additional low-income EE/DSM program pilots to present to the DEC and DEP EE/DSM Collaborative for consideration. Further, on the condition that the majority of EE/DSM Collaborative participants and DEP and DEC support the program pilots, DEP agreed to file for approval of the program pilots in North Carolina and South Carolina;

(3) within six months of the effective date of the Stipulation, the parties agreed to collaborate to design a tariffed on-bill pilot program, which shall include a Pay-As-You-Save® or other mutually agreeable alternative program design, for customers in North Carolina, addressing several listed issues. Within 18 months of the effective date of this agreement, DEP agreed to either (i) file the pilot for approval with the Commission, provided the parties mutually agree to the terms of the pilot program that is not less than three years in length and, in conjunction with the concurrent commitment of DEP, includes a combined total of no fewer than 700 but no more than 1000 residential customers, or (ii) file a status report with the Commission in this docket.

In addition, DEP agreed to preview a Distributed Generation Guidance Map for North Carolina with the DER Interconnection Technical Standards Review Group (TSRG) in the TSRG meeting during the third quarter of 2020, as well as in the August 2020 ISOP stakeholder meeting, after which DEP will incorporate TSRG and ISOP stakeholder input as appropriate and publish the Distributed Generation Guidance Map for North Carolina.

Further, DEP agreed to include in its 2021 IRP details about how both existing and new DERs and non-wires applications will be examined in its ISOP as means to defer traditional capital investments in the system. DEP will also implement the basic elements of the ISOP process in the 2022 IRP. Following the 2024 IRP, but no later than December 31, 2024, DEP agreed to provide hosting capacity analyses for a representative sample of DEP North Carolina circuits with other provisions and contingencies.

Finally, DEP agreed that it will reasonably include NCSEA/NCJC et al. for input and feedback at material points in its selection process as it identifies the tools and capabilities necessary for ISOP implementation. DEP will also reasonably consider and, where appropriate, incorporate input from the parties regarding the parameters that ISOP will use to assess issues such as distribution investment needs; the use of existing and future distributed energy resources and non-wires applications; load forecasts; pricing assumptions; and modeling inputs, keeping in mind the overall objective of developing investment plans that meet customer needs and preferences by capturing efficiencies from being a vertically integrated electric utility.

Vote Solar Stipulation

On July 9, 2020, DEP and Vote Solar entered into and filed the Vote Solar Stipulation, resolving some of the issues in this proceeding between these parties. No testimony supporting the settlement was filed.

As part of the Vote Solar Stipulation, DEP initially agreed that the revenues to be approved in this proceeding should be adjusted to provide the Company, through sound management, the opportunity to earn an ROE of 9.75% and that this ROE will be applied to the common equity component of the ratemaking capital structure consisting of 52% equity and 48% long-term debt. Vote Solar Stipulation, § II. Subsequently, on August 5, 2020, the parties filed an amendment to the Vote Solar Stipulation, providing that should the Commission approve an ROE of 9.60% applied to a capital structure of 52% equity, 48% debt, Paragraph II of the Stipulation should be deemed to be fulfilled.

Further, Vote Solar agreed to support the Company's request for an accounting order for approval to defer GIP costs for investments in Integrated System Operations Planning (ISOP), Integrated Volt Var Control (IVVC), Self-Optimizing Grid (SOG), Distribution Automation, Transmission System Intelligence, the Distributed Energy Resources (DER) Dispatch Tool, and the 44 kilovolt Line Rebuild. Vote Solar believed that these investments will directly enable and support the greater utilization of DERs on the Company's system. For all other GIP investments proposed by DEP, Vote Solar did not oppose the requested deferral accounting treatment. To the extent that DEP enters into an agreement with other intervening parties agreeing to a cost cap or to limit the amount of any GIP investment category specified for deferral treatment, Vote Solar supported such cost containment measures. Further, Vote Solar's support for the GIP deferral is subject to a reservation of its rights to review and object to the reasonableness of specific project costs in future rate cases.

In addition, DEP committed with Vote Solar to develop potential pilot customer programs prior to the submission of the 2022 IRP to optimize the capability of the GIP investments to support greater utilization of DERs, including customer sited solar and/or storage facilities (e.g., net metering successor), microgrid systems that benefit and would be paid for by specific benefitted customers, and programmable and load controllable devices or appliances for use in residential and nonresidential demand response programs. If DEP and Vote Solar mutually agree that these programs are cost-effective and meet appropriate Commission requirements, DEP agreed to file such pilot programs for approval by the Commission, and Vote Solar agreed to support such approval by the Commission.

Moreover, DEP agreed that within six months from the effective date of the Commission's order in this docket, DEP will convene a Climate Risk & Resilience Working Group (Working Group), governed by several parameters set out in the Stipulation. Within sixty days of the effective date of the Commission's order, the Company will make an informational filing in the docket to describe its scoping plan and proposed schedule for the Working Group and will give notice of such filing to all interested parties in all North Carolina and South Carolina dockets and stakeholder processes to which it is a party related to climate or decarbonization policy, the GIP, IRP, and ISOP.

DEP further agreed to fund a third-party consultant with experience developing models or analyses for quantifying climate-related impacts on the electric grid to assist stakeholders and the Company with the Working Group, subject to the contingency that DEP will recover the cost of the third-party consultant from ratepayers.

Discussion and Conclusions

As none of the partial stipulations have been adopted by all of the parties to this docket, the Commission's determination of whether to accept or reject each of the stipulations is governed by the standards set out by the North Carolina Supreme Court in *State ex rel. Utilities Commission v. Carolina Utility Customers Ass'n, Inc.*, 348 N.C. 452, 500 S.E.2d 693 (1998) (*CUCA I*), and *State ex rel. Utilities Commission v. Carolina Utility Customers Ass'n, Inc.*, 351 N.C. 223, 524 S.E.2d 10 (2000) (*CUCA II*). In *CUCA I*, the Supreme Court held:

> [A] stipulation entered into by less than all of the parties as to any facts or issues in a contested case proceeding under Chapter 62 should be accorded full consideration and weighed by the Commission with all other evidence presented by any of the parties in the proceeding. The Commission must consider the nonunanimous stipulation along with all the

> evidence presented and any other facts the Commission finds relevant to the fair and just determination of the proceeding. The Commission may even adopt the recommendations or provisions of the nonunanimous stipulation as long as the Commission sets forth its reasoning and makes "its own independent conclusion" supported by substantial evidence on the record that the proposal is just and reasonable to all parties in light of all the evidence presented.

348 N.C. at 466, 500 S.E.2d at 703.

However, as the Court made clear in *CUCA II*, the fact that fewer than all of the parties have adopted a settlement does not permit the Court to subject the Commission's Order adopting the provisions of a nonunanimous stipulation to a "heightened standard" of review. 351 N.C. at 231, 524 S.E.2d at 16. Rather, the Court said that Commission approval of the provisions of a nonunanimous stipulation "requires only that the Commission ma[k]e an independent determination supported by substantial evidence on the record [and] . . . satisf[y] the requirements of chapter 62 by independently considering and analyzing all the evidence and any other facts relevant to a determination that the proposal is just and reasonable to all parties." *Id.* at 231-32, 524 S.E.2d at 16.

The Commission finds and concludes that the provisions of the First and Second Partial Stipulations, as well as the stipulations with CIGFUR, Harris Teeter, Commercial Group, Vote Solar, NCSEA, and NCJC et al. result from the give-and-take between DEP and the stipulating parties and represent a compromise that is fair and adequate to each party. Pursuant to *CUCA I* and *II*, these nonunanimous stipulations are some evidence to be considered by the Commission in reaching its decision in this case. The Commission has fully evaluated the provisions of these stipulations and concludes, in the exercise of its independent judgment, that the stipulations should be accepted, in part, and rejected, in part, consistent with the specific discussion and resolution of the various issues discussed below. The parties are free to enter into stipulated provisions that pertain to actions or positions to be taken outside the confines of this proceeding; however, to the extent that DEP committed to certain actions or positions in future proceedings the Commission concludes that they are not relevant to any issue before the Commission in this case and do not tie the Commission's hands or limit future investigations.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

Base Fuel and Fuel-Related Cost Factors

The evidence supporting this finding of fact is found in the verified Application and Form E-1; the Public Staff Second Partial Stipulation; the testimony and exhibits of DEP witnesses McGee and Smith, and Public Staff witnesses Metz and Maness; and the entire record in this proceeding.

Summary of the Evidence

In her direct testimony DEP witness McGee supported the fuel component of proposed base rates for all customer classes and the fuel pro forma adjustments to the test year operating expenses contained in Smith Direct Exhibit 1. Tr. vol. 11, 50-51. Witness McGee proposed to use the total prospective fuel and fuel-related cost factors approved in Docket No. E-2, Sub 1173, and implemented December 1, 2018. *Id*. at 50. Witness McGee explained that these factors represented the fuel-related amounts DEP expected to collect from its North Carolina retail customers through its approved rates in the next billing period, and that DEP's intent in using the fuel-related factors that represent expected future rates as a component of its proposed new rates was to make it clear that the Company is requesting a rate increase that relates to non-fuel revenues only. *Id*. at 50-51.

Public Staff witness Metz testified that the base fuel factor in DEP's Application was appropriate for the Company's initial filing as it reflected the rates in effect at the time of the filing. Witness Metz stated that since the approved base fuel rate in Docket No. E-2, Sub 1204, DEP's previous annual fuel proceeding, went into effect December 1, 2019, the Sub 1204 rates would have to be refined in future Public Staff filings in this case. Witness Metz also stated that a future update would need to reflect the refinement of catalyst depreciation being shifted from fuel rates to base rates. Tr. vol. 15, 852-53.

In her supplemental testimony DEP witness McGee supported a revised base fuel factor to conform to the fuel rates approved in Sub 1204, and updated DEP's fuel costs based on revised weather and customer growth adjustments. Tr. vol. 11, 55-56.

In her supplemental testimony Company witness Smith presented an adjustment to update fuel costs to the Sub 1204 approved rates, explaining that the adjustment was also revised to reflect removal of catalyst depreciation from fuel clause recovery. Witness Smith also explained that after discussion with the Public Staff, DEP concluded that recovery of this expense in base rates is the most reasonable cost recovery approach. Tr. vol. 13, 172.

The Company filed its subsequent fuel factor adjustment case in Docket No. E-2, Sub 1250 on June 9, 2020. Section IV.O of the Second Partial Stipulation provided that should a final Commission order be issued in DEP's then ongoing annual fuel rider proceeding, Docket No. E-2, Sub 1250 (Sub 1250), prior to the date the proposed orders are due in this general rate case proceeding, the total of the approved base fuel and fuel related cost factors, by customer class, will be the sum of the respective base fuel and fuel-related cost factors set in Sub 1142 and the annual non-EMF fuel and fuel-related cost riders approved by the Commission in Sub 1250. Company witness Smith and Public Staff witness Maness supported the provision for the total approved base fuel and fuel related cost factors through their testimony in support of the Second Partial Stipulation. Tr. vol. 13, 260-61; tr. vol. 16, 34.

The Commission issued a final order in the Sub 1250 fuel rider proceeding on November 30, 2020. In the Sub 1250 order, the Commission concluded that, effective for service rendered on and after December 1, 2020, DEP shall adjust the base fuel and fuel-related costs in its North Carolina retail rates as approved in Sub 1142 of 1.993 cents/kWh, 2.088 cents/kWh, 2.431 cents/kWh, 2.253 cents/kWh, and 0.596 cents/kWh for the Residential, Small General Service, Medium General Service, Large General Service, and Lighting classes, respectively (all excluding regulatory fee), by amounts equal to 0.087 cents/kWh, 0.038 cents/kWh, (0.203) cents/kWh, (0.049 cents/kWh), and 0.796 cents/kWh, respectively. This results in total non-EMF fuel and fuel-related factors of 2.080 cents/kWh for the Residential class, 2.126 cents/kWh for the Small General Service class, 2.228 cents/kWh for the Medium General Service class, 2.204 cents/kWh for the Large General Service class, and 1.392 cents/kWh for the Lighting class, excluding the regulatory fee.

According to witness McGee the Company will continue to bill customers the fuel rates authorized by the Commission in its annual fuel proceedings. Tr. vol. 11, 52, 57. As such, there will be no change in customers' bills as a result of including these fuel cost factors in the proposed base rates. *Id*.

Discussion and Conclusion

No intervenor offered any evidence contesting the testimony of Company and Public Staff witnesses that supported the base fuel and fuel-related cost factors therein or the Public Staff Second Stipulation provision for the Company's base fuel and fuel related cost factors. Further, the Commission gives significant weight to Section IV.O of the Stipulation regarding the base fuel and fuel-related costs factors. Accordingly, the Commission finds and concludes for purposes of this proceeding that the total of the approved base fuel and fuel-related costs factors, by customer class — the sum of the respective base fuel and fuel-related costs factors set in Sub 1142 and the annual non-EMF fuel and fuel-related costs riders approved by the Commission in Sub 1250 — are just and reasonable to all parties in light of all the evidence presented.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5-9

Depreciation Study

The evidence supporting these findings of fact is found in the verified Application and Form E-1; the testimony and exhibits of DEP witness Spanos, Public Staff witness McCullar, and FPWC witness Brunault; and the entire record in this proceeding.

Summary of the Evidence

DEP Direct Testimony

Witness Spanos testified to the new deprecation study prepared for DEP for use in this proceeding. Tr. vol. 11, 210-11. He provided a copy of the Depreciation Study as

Exhibit 1 to his direct testimony. As explained by witness Spanos, the Depreciation Study included updates to estimates of final plant depreciation costs for steam, hydraulic, and other production plants, as well as updated forecasted generation plant retirement dates. In addition, witness Spanos noted that the Depreciation Study incorporates the full decommissioning cost values from the previously performed Burns and McDonnell decommissioning studies. These decommissioning studies included estimates for final decommissioning costs at steam, hydraulic, and other production plants.

Witness Spanos testified as to how he determined the depreciation rates included in the depreciation study. He further testified that he used the same methods and procedures to produce the current depreciation study as he has done in previous DEP depreciation studies.

Next, witness Spanos discussed the life span estimates for DEP's production facilities. He explained that those estimates are based on informed judgment that incorporates factors for each facility such as the technology of the facility, management plans and outlook for the facility, and estimates for similar facilities at other utilities. Witness Spanos stated that the life span estimates for nuclear and hydro facilities that have operating licenses were based on the license expiration dates for each facility. *Id.* at 218. The life span estimates used for depreciation rates for various fossil plants were also updated due to proposed changes to the probable retirement dates, with the life spans at Mayo Unit 1 and Roxboro Units 3 and 4 proposed to be shorter than currently approved. He further noted that the Asheville coal units 1 and 2 that were scheduled for retirement in 2019 will continue to be recovered through December 2027. *Id*.

Witness Spanos also discussed DEP's continued deployment of legacy electric meters with new technology meters, which was planned to be completed by the end of 2020. He indicated that, consistent with the Sub 1142 Order, the net book value (approximately $68 million) of the legacy meters will be amortized over 10 years. *Id*. at 219. Witness Spanos testified that the Depreciation Study included depreciation rates for the new Asheville combined cycle facility, with a 40-year life span for the location, as well as for new battery storage assets for generation, transmission, and distribution, with a 15-year life span for those resources. *Id.* at 226.

Witness Spanos also testified regarding net salvage. He testified that net salvage is a component of the service value of capital assets that is recovered through depreciation rates. The service value of an asset is its original cost less its net salvage. Net salvage is the salvage value received for the asset upon retirement less the cost to retire the asset. When the cost to retire exceeds the salvage value, the result is negative net salvage. Witness Spanos testified that the net salvage percentages estimated in the Depreciation Study were based on informed judgment that incorporated factors such as the statistical analyses of historical net salvage data; information provided by the Company's operating personnel, general knowledge and experience of industry practices; and trends in the industry. The statistical net salvage analyses incorporate the Company's actual historical data for the period 2003 through 2018 and considers the cost of removal and gross salvage ratios to the associated retirements during the 16-year period. He stated that trends of these data are also measured based on three-year moving averages and the most recent five-year indications.

FPWC Testimony

FPWC witness Brunault recommended two changes to the assumptions used in the 2018 Depreciation Study. He first recommended that the life spans of Mayo Unit 1 and Roxboro Units 3 and 4 be consistent with the retirement dates in DEP's 2019 IRP Update Report filed with the Commission on September 3, 2019 pursuant to Docket No. E-100, Sub 157, rather than the earlier dates utilized in the 2018 Depreciation Study. Tr. vol. 14, 52-56. He further recommended that the contingency allowance utilized in the 2018 Depreciation Study be reduced from 20% to the 10% approved by the Commission in the Sub 1142 proceeding. *Id*. at 69-71.

Public Staff Testimony

Public Staff witness McCullar testified that DEP was proposing an increase of $145 million in annual depreciation accrual. Tr. vol. 15, 781. She summarized that the Public Staff was recommending adjustments to reduce DEP's requested depreciation by $66.4 million. She noted that the Public Staff proposes changes to DEP's requested depreciation rates in the following functional categories: (1) Steam Production Plant (DEP is proposing 5.33% and Public Staff is proposing 4.13%); (2) Hydraulic Production Plant (DEP is proposing 3.70% and the Public Staff is proposing 3.65%); (3) Other Production Plant (DEP is proposing 5.08% and the Public Staff is proposing 5.03%; (4) Distribution Plant (DEP is proposing 2.34% and the Public Staff is proposing 2.32%); and (5) General Plant (DEP is proposing 5.74% and the Public Staff is proposing 4.39%). She noted that total depreciable plant as proposed by DEP is 3.60% and 3.35% as recommended by the Public Staff.

Witness McCullar specifically addressed the following additional issues in her testimony:

Contingency

Witness McCullar testified that DEP was again including a 20% contingency for future "unknowns", as included by DEP in this proceeding. She proposes to eliminate the 20% contingency for future "unknowns" and noted the 2018 DEP Rate Order in which the Commission ordered that a 10% contingency factor be used.

Mass Property Future Net Salvage

Witness McCullar testified that she had reviewed the reasonableness of DEP's proposed future net salvage for a mass property account and she was recommending three changes: (1) a -75% for the Poles, Towers and Fixtures, Account 364, which is different than the proposed -100% by DEP; (2) a -10% for the Underground Conduit, Account 366, which is different than DEP's proposed -15% for this account; and

(3) a -15% for the Services, Account 369, which is different than DEP's proposed -20% for this account. Witness McCullar noted that salvage ratios are a function of inflation and that the calculation of the historic net salvage ratio includes the impact of high historic inflation rates since the net salvage amount in the numerator is in current dollars and the cost of the plant (which may have been installed decades before) in the denominator is in historic dollars. In other words, due to inflation, the amounts in numerator and denominator of the net salvage ratio are at different price levels. Witness McCullar testified that her proposed future net salvage accrual amounts consider DEP's historic practices, the impact of inflation, and builds a reserve for reasonable estimated future net removal costs associated with future retirements, based on the type of investments in the account, and her previous experience.

AMI Meters

DEP requested a 15-year depreciation life for AMI meters in this proceeding. As explained by witness Spanos, a 15-S2.5 survivor curve was recommended by DEP for AMI meters. Tr. vol. 11, 197. This estimate was consistent with the manufacturer's recommendation for the physical life of the AMI meters and accounted for alternative reasons for retirement such as damage or obsolescence. *Id.*

Public Staff witness McCullar recommended a 17-year service life for AMI meters. Tr. vol. 16, 615. Witness McCullar testified that a 17-year life is in the middle of the manufacturer's range, is a reasonable estimate based on the manufacturer's expected life of the AMI meters, and is fair to the Company and the ratepayer. *Id.*

Continued Use of Amortization Period for General Plant Accounts 391 and 397

Public Staff witness McCullar testified that in the Sub 1142 proceeding, the Commission found that the 20-year amortization period stipulated by the Public Staff and DEP for two general plant accounts: Account 391, Office Furniture and Equipment; and Account 397, Communication Equipment, was reasonable. Tr. vol. 15, 802-03. In this proceeding, DEP proposed to change the current approved 20-year amortization period for Account 391, Office Furniture and Equipment to a 15-year amortization, and the current approved 20-year amortization period for Account 397, Communication Equipment, to a 10-year amortization period. Public Staff witness McCullar noted that the 2018 Depreciation Study did not provide any data supporting the proposed change but noted that the lack of life data is not uncommon for amortized accounts due to the change in record-keeping when an account switches from depreciation accounting to amortization accounting. *Id.* at 805. Witness McCullar further explained that under amortization accounting, DEP no longer keeps the detailed records needed to populate the original life tables. DEP tracks the installation year, but the asset will be retired off the books when it reaches the approved average service life, regardless of whether that asset is still in service. She stated that the use of amortization accounting for these smaller value general plant accounts is used to minimize the accounting expense involved in keeping the detailed records used in depreciation accounting. *Id.*

Witness McCullar further testified that prior to the switch to amortization accounting in the Sub 1142 Proceeding, the approved service life for Account 391, Office Furniture and Equipment was 20 years, and the approved service life for Account 397, Communication Equipment was 27 years.

DEP Rebuttal Testimony

DEP witness Spanos noted his disagreement with the recommendations of FPWC witness Brunault and Public Staff witness McCullar to continue to use the 10% contingency previously approved by the Commission, stating that the terminal net salvage estimates used in the calculation of depreciation rates were based on a comprehensive decommissioning study that incorporated a 20% contingency. Tr. vol. 16, 295. He did not, however, provide any specific breakdown of costs to support the statement, other than to indicate that it was supported by the testimony of DEP witness Kopp in the Sub 1142 proceeding, and that the context of other proposals in this case and that coal ash costs show that end of life costs can be higher than originally anticipated provide additional support for the need for contingency. *Id.* at 295-96.

Regarding the adjustments to mass property accounts, DEP witness Spanos in rebuttal stated that Public Staff witness McCullar's recommendations for production plant accounts were consistent with the Commission's decision in the Sub 1142 Order, her recommendations regarding mass property distribution plant were not consistent with prior Commission decisions. *Id.* at 285. Further, he noted that FERC has confirmed that the estimated future net salvage costs should be included in depreciation. *Id*. at 290. He also testified that he did not believe that witness McCullar's analysis provides a reasonable basis to estimate future net salvage because it is based on the premise that depreciation accruals for net salvage should be similar to, if not the same as, the net salvage occurred each year. *Id*. at 294. He stated that the goal of depreciation is to recover capital costs, including net salvage over the service life of the assets, and that there is not necessarily alignment between depreciation accruals for net salvage and incurred net salvage. Lastly, he noted that expressing historical net salvage as a percentage of historical retirements as he proposes properly recognizes the relationship between net salvage and retirements. *Id.* at 295.

Regarding the lifespan of the AMI meters, DEP witness Spanos acknowledged on rebuttal that the Commission accepted a 17-year average service life for AMI meters in the Sub 1142 proceeding but noted that the Commission adopted a 15-year average service life for AMI meters in the last DEC rate case in Docket No. E-7, Sub 1146 (Sub 1146). *Id*. at 296-97. He recommended continuing to use the 15-S2.5 survivor curve, which he stated is consistent with the manufacturer's recommendation for the physical life of AMI meters but also considers that meters are retired for other reasons, such as damage or obsolescence. *Id.*

On cross-examination DEP witness Spanos acknowledged that although the Commission had concluded in the Sub 1146 Order that production plant accounts should be escalated to the date of retirement it had not made such a finding related to mass property salvage accounts. *Id.* at 373-74. Further, he acknowledged that the FERC Order discussed in his testimony did not address mass property net salvage accounts. *Id.* at 376.

During redirect DEP witness Spanos stated there was no compelling reason for DEP to use a different amortization period for these accounts than DEC, also noting that witness McCullar was a witness in the current DEC case in Docket No. E-7, Sub 1214, but had not challenged the amortization periods for these two accounts in that case. *Id.* at 305-06. He further disputed Public Staff witness McCullar's analysis in the Sub 1142 proceeding used to support the longer lives for the assets, noting that it relied in part on historical life analysis and that, due to the nature of the assets in these accounts (many units with small dollar values), many companies historically had difficulty tracking retirements. *Id.*

DEP witness Spanos also disputed witness McCullar's proposals for Accounts 391 and 397, in that she had excluded "millions of dollars of investment from her calculations of depreciation expense" for the two accounts. *Id.* at 307; *see also id.* at 383-86.

Discussion

Contingency Factor

Public Staff witness McCullar recommended that the currently approved 10% contingency for future "unknowns" included in DEP's estimate of future terminal net salvage costs continue to be used, as opposed to the 20% proposed by the Company. Tr. vol. 15, 789. Witness McCullar noted that in the Sub 1146 Order, the Commission approved the use of a 10% contingency factor, stating that:

> The Commission is confident that a 10% contingency factor, while less than DEC's requested factor of 20%, should protect the Company from additional costs it will incur but cannot specify at the present date. The Commission also finds that a 10% contingency factor properly reflects the inclusion of items that should push unknown costs downward (i.e. increase in scrap prices, etc.) thereby protecting the ratepayers as well. Based on the foregoing, the Commission concludes that including a contingency factor of 10% should be utilized by the Company.

2018 DEC Rate Order at 172-73.

In rebuttal witness Spanos testified that the terminal net salvage estimates used in the calculation of depreciation rates were based on a decommissioning study performed by Burns and McDonnell. The Decommissioning Study incorporates a 20% contingency and this study, as well as DE Progress witness Kopp's testimony in DEP's previous rate case, provide the justification for this contingency factor. Tr. vol. 16, 295-96. Witness Spanos further noted that the intent of adding the contingency is to ensure that decommissioning activity is fully funded at the point of retirement.

The Commission agrees with DEP that including a contingency is a standard industry practice to cover potential unknown or unexpected costs. However, the Commission also agrees with the Public Staff that DEP has presented no new information or data supporting the need for a contingency percentage greater than the 10% contingency agreed to by stipulation and accepted in the Sub 1142 Order, or the 10% contingency approved by the Commission in the Sub 1146 Order for DEC. As quoted above, in that proceeding, the Commission expressed some concern regarding the accuracy of the Decommissioning Study, finding that DEC failed to consider certain factors, but concluded that a 10% contingency was fair to all parties.

The Commission acknowledges witness Spanos's experience and expertise, yet it notes that the contingency percentage utilized in the Depreciation Study and recommended in his testimony is based on the same Decommissioning Study used in the Sub 1142 proceeding. In addition, witness Spanos did not provide any new data or information to support his claims regarding recent industry experience supporting an increased contingency percentage. This unsupported position would inappropriately shift a greater portion of the risk of future unknown, unidentified costs on current ratepayers.

The Commission finds that the increased contingency proposed by DEP in this proceeding lacks sufficient basis and therefore concludes that it is reasonable and appropriate for DEP to continue to use a contingency factor of 10% for net terminal salvage.

Mass Property Future Net Salvage

Net salvage estimates are expressed as a percentage of the original cost retired. Tr. vol. 16, 286. The method for determining the estimated net salvage percent depends on the type of property. *Id.* For power plants, the estimate is typically based on a decommissioning study, with additional net salvage incorporated for interim retirements. *Id*. at 286-87. For mass property accounts such as those for transmission and distribution plant, net salvage estimates are based in part on statistical analyses of historical net salvage data. *Id.* at 287. In this case, the statistical net salvage analyses incorporate the Company's actual historical data from 1979 through 2018 and considers the cost of removal and gross salvage ratios to the associated retirements during the 40-year period. *Id.* at 249.

Witness Spanos recommended a net salvage percentage of negative 100% for Account 364, Poles, Towers and Fixtures, negative 15% for Account 366, Underground Conduit, and negative 20% for Account 369, Services. Witness McCullar recommended a future net salvage percent of negative 75% for Account 364, negative 10% for Account 366, and negative 15% for Account 369. Tr. vol. 15, 792. Witness McCullar expressed concern with the Company's historic net salvage ratios calculated in the Depreciation Study. *Id.* at 794-95. Specifically, witness McCullar took issue with using a net salvage ratio that includes inflated dollars in the numerator and historic dollars in the denominator. *Id.* Witness McCullar explained that due to inflation the amounts in the numerator and denominator of the net salvage ratio are at different price levels. *Id.* at 795. Witness

McCullar noted that five other jurisdictions have adopted future net salvage percentages that recognized the inflated dollars included in the historic net salvage ratio and adopted future net salvage percentages that recognize the time value of cost of removal due to inflation. Tr. vol. 16, 287-88.

In response witness Spanos testified that witness McCullar's proposal is not consistent with the Commission's decision in Sub 1146 and is unsupported by the record. *Id.* at 286. Witness McCullar supported her treatment of Accounts 364, 366, and 369 by arguing against including future inflation in net salvage estimates. *Id.* at 285. Witness McCullar also noted that five other jurisdictions have removed the escalation of estimated future terminal net salvage costs. Tr. vol. 15, 795-98. As witness Spanos previously testified, the Commission has already decided against witness McCullar's position on this concept and found that the Company's approach was widely supported. Overall, while witness McCullar's proposals for these accounts does not have as significant an impact as her proposals for other accounts, she did not provide any statistical basis for her proposal. *Id.* The only analytical method witness McCullar provided in support of her proposal was a comparison of the net salvage costs included in the proposed depreciation rates to the amount of net salvage DEP has incurred, on average, over the past five years. *Id.* at 294. This type of analysis does not provide a reasonable basis to estimate net salvage. Additionally, witness Spanos testified that NARUC and Wolf and Fitch do not support witness McCullar's approach for mass property accounts, and further stated that the Company is unaware of any authoritative texts that support witness McCullar's analysis. *Id.* at 293-95.

Witness Spanos was also asked on cross-examination about the net salvage calculation in an Atmos Energy rate proceeding in Kansas in which witness McCullar testified. Public Staff Spanos Cross-Examination Ex. 3. This testimony did not undermine witness Spanos' position on net salvage, however, because it was clear from the face of the order in that proceeding that the Kansas Commission explicitly rejected a proposed negative salvage calculation based on a "recent history" approach similar to that offered by witness McCullar in this case.

Considering all of the evidence, the Commission finds and concludes that the Company's proposed future net salvage rates for mass property Accounts 364, 366, and 369 are just and reasonable, appropriate for use in this case, and are adopted.

Service Life for AMI Meters

DEP requested a 15-year depreciation life for AMI meters. As explained by witness Spanos, a 15-S2.5 survivor curve was recommended by DEC for AMI meters, which the Commission previously approved in Sub 1146. Tr. vol. 16 at 297. This estimate was consistent with the manufacturer's recommendation for the physical life of the AMI meters and accounted for alternative reasons for retirement such as damage or obsolescence. *Id.*

Public Staff witness McCullar recommended a 17-year service life for AMI meters. Tr. vol. 15, 792. Witness McCullar testified that a 17-year life is in the middle of the manufacturer's range, is a reasonable estimate based on the manufacturer's expected life of the AMI meters, and is fair to the Company and the ratepayer. *Id.* at 791-92.

In response witness Spanos pointed out that the Commission approved the 15- year service life for AMI meters in the 2018 DEC Rate Order. Tr. vol. 16, 296-98. DEP used a 15-year average service life in its previous depreciation study in Sub 1142. *Id*. at 296. In the 2018 DEC Rate Order, the Commission adopted the 15-year average service life. *Id.* at 297. Moreover, DEC's cost-benefit analysis for AMI meters was based on a 15-year average service life and the Commission had specifically requested that such analysis include the "cost of replacing AMI meters at the end of their 15-year useful life."

Witness McCullar has not provided any new evidence in the instant case that supports changing the 15-year average service life previously approved by the Commission. Witness McCullar's arguments are almost identical to those she presented in Sub 1146, which were not persuasive to the Commission. Additionally, witness McCullar simply took the mid-range of the manufacturer's life without considering issues like technological obsolescence. In that regard, witness McCullar made no attempt to distinguish the type of asset, which is a critical consideration when there is limited historical experience.

Based on all the evidence the Commission finds and concludes that the Company's request to establish a 15-year average service life for AMI meters is just and reasonable and appropriate for use in this case.

Amortization Period for General Plant – Accounts 391 and 397

The Commission finds that DEP did not present sufficient evidence in this proceeding to justify reducing the current approved amortization period for the two general plant accounts in question. While consistent treatment of these accounts between DEC and DEP is one consideration, there may be valid reasons for maintaining different amortization periods between the companies for these accounts. As noted by witness Spanos, one of the primary benefits of general plant amortization is to reduce accounting expenses associated with tracking the retirement of individual assets. However, as noted by witness McCullar, DEP no longer keeps detailed historic life records for these amortized accounts therefore, there is not sufficient data in this proceeding that the original amortization periods, which were consistent with the historic life data available in the previous docket, are unreasonable.

For purposes of this proceeding, the Commission believes it is appropriate for DEP to continue to use the 20-year amortization period for Accounts 391 and 397 that were approved at the time these accounts were switched from depreciation accounts to amortization accounts. To the extent DEP identifies adjustments needed to adjust the remaining life calculation and update the reserve allocation adjustment for amortization for each account to reflect the use of a 20-year amortization period, the Commission directs DEP to identify these adjustments in its compliance filing.

Conclusions

In sum, and based on the foregoing conclusions, the Commission finds that DEP shall: (1) continue to use a 10% contingency in the estimate of future terminal net salvage costs; (2) use its proposed future net salvage rates for mass property Accounts 364, 366, and 369; (3) use an average service life of 15 years for new AMI meters being deployed; and (4) continue to use a 20-year amortization for Accounts 391 and 397. The Commission further concludes that except where specifically addressed in this Order, the remaining depreciation rates as proposed by DEP in this case shall be used in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 10-11

Early Retirement of Coal Plants

The evidence supporting these findings of fact is found in the verified Application and Form E-1; the testimony and exhibits of DEP witnesses De May and Spanos, Public Staff witnesses McCullar, Dorgan, and Metz, and FPWC witness Brunault; and the entire record in this proceeding.

Summary of the Evidence

In its new depreciation study DEP shortened the life span estimates of Mayo Unit 1 and Roxboro Units 3 and 4 from those currently approved. DEP witness Spanos explained that the life span estimates for DEP's production facilities are based on informed judgment, incorporating factors for each facility such as the technology of the facility, management plans and outlook for the facility, and estimates for similar facilities at other utilities. Tr. vol. 11, 218. He further noted that the Asheville coal units 1 and 2 that were scheduled for retirement in 2019 will continue to be recovered through December 2027. *Id.* Witness Spanos stated that the revised life spans are reasonable because, in recent years, original life spans for steam production facilities have been shortened due to unit efficiencies and operating costs (driven in part by environmental regulations). *Id.* at 299.

Public Staff witness McCullar calculated depreciation rates using the retirement dates from the previous depreciation study. Tr. vol. 16, 806. Public Staff witness Dorgan recommended that witness McCullar restore the depreciation rate of Mayo Unit 1 and Roxboro Units 3 and 4 to the depreciation rate approved in Sub 1142, for the following reasons: (1) although the Company has stated in its testimony that it intends to retire these plants, it has not presently done so; (2) the Public Staff has consistently recommended leaving the depreciation rates set at the original retirement date of the plant, and, at the date of actual physical retirement, any remaining net book value be placed in a regulatory asset account and amortized over an appropriate period, to be determined in a future general rate case; and (3) given operational concerns, the Public Staff believes it is appropriate to continue this consistent treatment of retired plants. Tr. vol. 15, 734.

Public Staff witness Metz testified that DEP's retirement dates proposed in this case are earlier than those shown in DEP's 2018 IRP and its 2019 Update, filed in Docket No. E-100, Sub 157. Witness Metz further testified he believed that the Company's IRP proceeding is the appropriate venue for a thorough review of early, or any, generation retirements.

FPWC witness Brunault recommended that the lifespans of Mayo Unit 1 and Roxboro Units 3 and 4 be consistent with the retirement dates in DEP's 2019 IRP Update Report filed with the Commission on September 3, 2019, in Docket No. E-100, Sub 157, rather than the earlier dates utilized in the 2018 Depreciation Study. Tr. vol. 14, 52-56.

In rebuttal DEP witness De May noted the ongoing pressure to meet aggressive carbon reduction and emissions goals and to adapt further climate change-related policymaking. Tr. vol. 11, 777.

DEP witness Spanos testified that the Uniform System of Accounts (USOA) requires that depreciation recover the costs of an asset over its service life. Tr. vol. 16, 300. Recovering costs after an asset is retired results in intergenerational inequity because future customers, who will not receive service from the retired asset, are forced to bear the costs for an asset that is already retired. *Id.* Witness Spanos explained that Public Staff's proposal will result in intergenerational inequity because it will result in DEP recovering a portion of the costs of Mayo Unit 1 and Roxboro Units 3 and 4 after they are retired. *Id.* at 300-02. Witness Spanos also challenged witness Dorgan's other justifications. *Id.* at 301-02. He further stated that the Public Staff's proposal will, by design, result in intergenerational inequity.

On cross-examination, witness Spanos accepted that under N.C.G.S. § 62-35 the Commission sets the rules for DEP's North Carolina retail accounting practices. Witness Spanos further agreed that Commission Rule R8-27 currently provides for the FERC Uniform System of Accounts to be the default system of accounts for electric utilities that are regulated by the Commission. Finally, witness Spanos testified that the Commission has historically provided for undepreciated balances to be recovered from customers after assets have been retired. During cross-examination witness Spanos was presented with two examples in which remaining unrecovered depreciation of DEP's plants were recovered from ratepayers in the years after they were retired.

Discussion and Conclusions

Based on the foregoing and the record, the Commission finds that it is appropriate to require DEP to continue to depreciate the Mayo Unit 1 and Roxboro Units 3 and 4 generating plants based upon their remaining useful life as approved in Sub 1142. In reaching this conclusion, the Commission gives significant weight to the testimony of

Public Staff witnesses Dorgan and Metz. The Commission agrees with witness Metz that the Company's IRP proceeding is the appropriate venue for a thorough review of early, or any, generation retirements. Moreover, the Commission notes that the Company did not file the requested accelerated depreciation for the plants in either its 2018 IRP or the 2019 Update.

Witness Dorgan stated that the Public Staff has consistently recommended leaving the depreciation rates set at the original retirement date of the plant, and, at the date of actual physical retirement any remaining net book value be placed in a regulatory asset account and amortized over an appropriate period, to be determined in a future general rate case. The Commission determines that this methodology is supported by the examples the Public Staff provided during cross-examination of Company witness Spanos. When presented with Public Staff Doss Spanos Rebuttal Cross-Examination Exhibit No. 2, witness Spanos affirmed that Duke Energy requested the same methodology proposed by the Public Staff in this proceeding in Sub 1142. Witness Spanos further confirmed this same treatment was approved by the Commission in Docket No. E-2, Sub 1023 for retirement of DEP's Cape Fear, Lee, Robinson, Weatherspoon, and Morehead City coal plants.

The Commission has consistently strived to balance allowing utility companies to receive full recovery of early retirement costs while not unduly burdening ratepayers. In the present case the Company's proposed accelerated depreciation would unduly burden the ratepayers for the next several years as they would be paying more for electric service. DEP on the other hand would be recovering the plants' costs more quickly than last projected in its IRP, which is where generation mix and service lives of DEP's assets are fully vetted. As DEP has not updated its IRP for the proposed service life changes of the Mayo Unit 1 and Roxboro Units 3 and 4 generating plants, the Commission and other parties have not had the chance to fully examine the issue within the confines of an IRP. For these reasons, the Commission finds the Company's approach to be unbalanced.

Therefore, in light of the foregoing, the Commission concludes that the depreciation for the Mayo Unit 1 and Roxboro Units 3 and 4 generating plants should be based upon the remaining life as presented in Sub 1142 and, upon actual retirement of each unit, the remaining undepreciated net book value placed in a regulatory asset account to be amortized over an appropriate period determined in a future rate case.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12-14

Coal and Nuclear Fleet Investments

The evidence supporting these findings of fact is found in the verified Application and Form E-1; the testimony and exhibits of DEP witnesses Turner and Henderson, Public Staff witness Metz, NC WARN witness Powers, and Sierra Club witness Wilson; and the entire record in this proceeding.

Summary of the Evidence

DEP Direct Testimony

Company witness Turner described the Company's fossil/hydro/solar (FHO) generation assets and provided operational performance results for those assets during the test period. Tr. vol. 11, 970-71, 975-77. Witness Turner testified to the major FHO capital additions DEP has completed since the previous rate case, explaining that the Company has made significant investments in the coal fleet to meet environmental regulations to allow for the continued operation of active plants. *Id.* at 972. Witness Turner also discussed the addition of the Asheville CC Project units, and the retirement of the two Asheville Steam Electric Generating Plant units, anticipated by the end of 2019. In addition, she explained that the Asheville CC Project, for which DEP received a certificate of public convenience and necessity (CPCN) from the Commission in Docket No. E-2, Sub 1089 (Asheville CPCN Order), features state-of-the-art technology for increased efficiency and reduced emissions. *Id.* at 971-72. Witness Turner testified that the Company prudently incurred all of these costs and addressed the key drivers impacting O&M expenses. *Id.* at 973-75. Furthermore, she stated that these investments would be used and useful in providing electric service by the capital cutoff date, and benefit customers, as they have enabled DEP to continue to provide safe, efficient, and reliable service at least reasonable cost. They have also reduced the Company's environmental footprint by adding state-of-the-art technology for reducing emissions, retiring older facilities that lacked environmental equipment and were not economically positioned for needed capital expenditures, and expanding the use of natural gas generation at a time when the natural gas market is providing low prices. *Id*. at 973-74.

Company witness Henderson described DEP's nuclear generation assets and capital additions to the nuclear fleet made to enhance safety, address regulatory requirements, and preserve performance and reliability of these plants throughout their extended life operations. Tr. vol. 11, 127-32. Witness Henderson testified that these capital additions and enhancements are used and useful in safely and efficiently providing reliable service to DEP customers and position the Company to maintain the high levels of operational safety, efficiency and reliability reflected in the fleet's performance results. *Id*. at 132. Witness Henderson also discussed key drivers impacting nuclear O&M costs, including inflationary pressure on labor and materials, and the Company's strategy for mitigating that pressure. Witness Henderson noted that customers will continue to benefit from the strong performance of DEP's nuclear fleet through lower fuel costs. *Id*. at 132-34. Witness Henderson described DEP's current status with respect to compliance with Nuclear Regulatory Commission (NRC) requirements. *Id*. at 135-39. Finally, he discussed the high performance of the Company's nuclear fleet during the test period and the steps DEP has taken to increase efficiencies in nuclear operations. *Id*. at 139-42.

Public Staff Testimony

Public Staff witness Metz discussed his review of DEP's capital additions to both the FHO and nuclear fleets, in which he looked at multiple aspects of capital spend to evaluate them for reasonableness and prudence, as well as whether the asset or result of the capital investment was used and useful. Witness Metz noted that his investigation included, in addition to reviewing prefiled direct testimony, an audit of specific expenditures, initial and follow-up discovery, teleconferences between and interviews with the Company and Public Staff, site visits, and review of the overall projects with Company management. Tr. vol. 15, 821-22. Witness Metz discussed the status of the Asheville CC Project and the repairs that had been required at one of the steam turbine components of that project, concluding that the Company was not at fault for the events necessitating the repairs. *Id*. at 823-24. The Public Staff did not recommend any disallowance of the Company's request for recovery of its capital investments in either its FHO or nuclear fleets based on imprudence. *Id.* at 824.

Sierra Club Testimony

Sierra Club witness Wilson recommended disallowance of all of the Company's FHO capital expenditures made between the Sub 1142 rate case and the current case, based on her contention that the net value of each of the coal units was negative for the 2016-2018 time period, until DEP provides evidence of an analysis demonstrating the value of the investment done at the time the investment decision was made. In addition, she claimed that DEP did not demonstrate the prudence of its historical capital investments in its coal units. Tr. vol. 15, 42-47, 54, 56. Witness Wilson acknowledged the advancement of the probable retirement dates of certain units based on the Company's updated depreciation study. *Id.* at 36-37. She also acknowledged that retirement of the entire coal fleet at once would likely lead to reliability issues in DEP's service territory. *Id.* at 50.

Based on her projected future energy value of the DEP coal fleet and citing to the Georgia Public Service Commission (Georgia Commission) as having taken similar action, she also recommended that the Commission cap future capital expenditures intended to prolong the lives of these units and require DEP to obtain Commission approval of any expenditure that exceeds the cap before it can be recovered from customers. *Id.* at 47-54. Further, she recommended that the Commission disallow recovery of "ongoing" O&M expenses at DEP's coal units. *Id*. at 57. Witness Wilson also recommended that in future rate cases, DEP be required to demonstrate that its natural gas units are providing positive net value to ratepayers before being granted recovery of capital and O&M costs. *Id*. at 50-54. Finally, she suggested that the used and useful standard could be interpreted to mean that if there was a power plant construction project planned in a prudent manner, that operates at costs significantly higher than the economic value of the output for reasons beyond the utility's control and ability to reasonably foresee, the plant may be found prudent and used, but not economically useful. *Id.* at 55.

On cross-examination witness Wilson agreed that as DEP transitions away from reliance on coal it must nonetheless continue to meet its obligation to provide safe and reliable electric service to customers. *Id.* at 65. Witness Wilson acknowledged that her testimony did not specify any particular project or costs that DEP should not have incurred, did not offer other options that DEP could have chosen instead of incurring any of the costs it seeks to recover now, and that her analysis did not analyze the Company's decisions about coal fleet investments at the time it made those decisions. *Id.* at 98-99. Witness Wilson testified that she was not aware of the North Carolina standard for challenging prudence that requires a party to identify specific instances of imprudence and provide a prudent alternative. *Id.* at 68. Regarding her testimony on the "used and useful" standard, she could not identify any state commission that had adopted her interpretation of that standard. *Id.* at 72.

Witness Wilson also agreed that some coal fleet environmental investments were required whether or not the units continued to operate.*Id.* at 76-77. She testified that she did not analyze whether shutting the units down was a feasible path DEP could have chosen while continuing to meet its service obligations. *Id.* at 77-78. Witness Wilson acknowledged that her analysis did not consider whether it would have been feasible or cost-effective for DEP to retire Mayo or Roxboro Stations rather than make the investments the Company is seeking to recover in this case. *Id.* at 103.

NC WARN Testimony

NC WARN witness Powers recommended disallowance of the Company's costs for the Asheville CC Project. Tr. vol. 15, 885. Witness Powers claimed that DEP's investments in this project were not reasonably and prudently incurred based on his contention that the project was not needed. *Id*. at 886. Specifically, he asserted that DEP could have avoided investing in the Asheville CC Project by relying on regional merchant combined cycle, hydroelectric plants, and the addition of battery storage at existing North Carolina solar facilities. *Id*. at 882-885. Finally, he compared his estimation of the production cost at the Asheville CC Project to approximations of production costs for hydroelectric and battery storage resources. *Id*. at 881-84.

DEP Rebuttal Testimony

In rebuttal witness Turner addressed the testimony and recommendations of witnesses Wilson and Powers. Tr. vol. 11, 989-991. She explained that such contentions fail to recognize the full picture of how DEP dispatches its coal fleet to maximize value for customers. Witness Turner noted that witness Wilson's study did not appear to account for the requirement of day-ahead planning reserves and explained that capacity must be online or available within 10 minutes. Further, she stated that a coal unit will provide energy and capacity during the peak, and that if a needed coal unit is not online then the Company must start additional combustion turbines or purchase energy and capacity from the market, if capacity is available during such a time. *Id*. at 991-92.

Witness Turner also testified that witness Wilson's forward-looking analysis of the coal fleet is not a valid exercise for a general rate case. *Id.* at 992. Witness Turner noted that witness Wilson did not explain how her proposed cap on future coal fleet investments would be determined and clarified that these investments were made to maximize the remaining useful life of the units. Witness Turner stated that the Company cannot recover such costs from customers unless and until the Commission permits it to do so. Finally, she clarified that estimates of future capital investments are not relevant to this proceeding. *Id.* at 992-93.

Witness Turner also testified that witness Powers did not offer a credible and specific explanation of how DEP could have replaced the reliable generation provided by the Asheville CC Project and did not otherwise credibly challenge the Company's reasonable and prudent decision to invest in this project. In addition, she noted that NC WARN ignored additional factors that supported the reasonableness and prudence of this investment, including the Mountain Energy Act, which specifically contemplated DEP's construction of a new natural gas fired generating facility at the Asheville site, and the Commission's Asheville CPCN Order which determined that the project was needed. *Id*. at 994-95.

Witness Turner also explained that DEP did not conduct a comprehensive retirement analysis regarding investment in environmental compliance projects at Roxboro Station but performed a similar analysis for Mayo Station, which indicated in all scenarios studied that it was not economical for customers to retire and replace Mayo Station with environmental investments. As a result – and given that Mayo Station has a 700 MW capacity – it was also not likely to be economical for Roxboro Station, which has a capacity of 2400 MW. In addition, witness Turner stated that the energy produced by these stations was required for DEP to reliably serve its customers, and DEP could not have replaced these resources in the period of time available. *Id.* at 1002-03, 1005. Witness Turner also explained that each of the scenarios evaluated in the Mayo study considered natural gas as the alternative, because natural gas was determined to be the most economical type of generation resource as shown in the Company's most recent IRP at that time. *Id.* at 1003-04.

During redirect examination witness Turner clarified that the portion of total investments DEP made at Roxboro and Mayo Stations related to environmental compliance exceeded the portion for maintenance capital investments at those stations. *Id.* at 1006-07. In addition, she confirmed that the Company would have had to make approximately half of the environmental investments even if it retired these units early, in order to remain compliant with environmental regulations while the units were still operating. *Id.* at 1007. Witness Turner also described the disciplined process DEP uses to evaluate whether to make investments in its coal fleet and confirmed that the Company operates and makes investment decisions based on information available at the time. Witness Turner also described how the Company's investments in its coal fleet have benefitted customers, explaining for example that while capacity factors for the coal fleet have declined in recent years, these units' capacity is critical to the DEP system as evidenced by the 94% capacity factor at the Roxboro and Mayo units during early January 2018. Witness Turner confirmed that DEP's coal fleet investments have allowed the Company to remain environmentally compliant and to continue to provide safe and reliable service to customers. *Id.* at 1008-10. She testified that the updated plans for DEP's coal fleet presented in the Company's 2020 IRP are consistent with its proposal in this case to accelerate the depreciable lives of some of those units. *Id*. at 1010-11.

Discussion and Conclusions

Based on the entire record in this proceeding, the Commission finds and concludes that the costs associated with the Company's investments in its coal fleet were reasonably and prudently incurred and should be recovered. The Commission further finds and concludes that based on this record the Sierra Club's additional recommendations to limit the Company's future investments in its coal and natural gas units should not be adopted at this time. Finally, the Commission finds and concludes that the costs associated with the Company's investments in its nuclear generating fleet were reasonably and prudently incurred and should be recovered.

When setting just and reasonable rates the Commission must determine whether costs incurred by the utility were prudently incurred, which involves an examination of whether the utility's actions, inactions, or decisions to incur costs were reasonable based on what it knew or reasonably should have known at the time the actions, inactions, or decision to incur costs were made. When challenging prudence the challenger is required to (1) identify specific and discrete instances of imprudence; (2) demonstrate the existence of prudent alternatives; and (3) quantify the effects by calculating imprudently incurred costs. Detailed proof or analysis must also be provided. Order Granting Partial Increase in Rates and Charges, *Application by Carolina Power & Light Company for Authority to Adjust and Increase Its Electric Rates and Charges*, Docket No. E-2, Sub 537, 78 N.C.U.C. Orders & Decisions 238, 251-52 (Aug. 5, 1988) (*Harris Order*), *reversed in part*, *and remanded on other ground*, *Utilities Commission v. Thornburg*, 325 N.C. 484, 385 S.E.2d 463 (1989).

The burden of proof to show that rates are just and reasonable is on the utility. N.C.G.S. § 62-134(c). Nevertheless, intervenors have a burden of production if they dispute an aspect of the utility's prima facie case. *See, e.g., State ex rel. Utils. Comm'n. v. Intervenor Residents of Bent Creek/Mt. Carmel Subdivisions*, 305 N.C. 62, 76, 286 S.E.2d 770, 779 (1982) (*Bent Creek*). If the intervenor meets its burden of production through the presentation of competent, material evidence, then the ultimate burden of persuasion reverts to the utility, in accordance with N.C.G.S. § 62-134(c).

The Commission gives substantial weight to the testimony of Company witness Turner regarding the prudency of the costs of DEP's investments in its coal fleet. Witness Turner explained in detail how the Company prudently determined that these investments were needed to maintain DEP's remaining active coal units to continue to provide safe, reliable, and cost-effective electric service to customers. He explained that a significant portion of these costs were required under environmental law or regulation regardless of whether the Company continued to run the units and that a large portion of the remaining costs were incurred to maintain compliance with environmental requirements to continue to operate the units. Regarding the Asheville CC Project, witness Turner presented convincing evidence in rebuttal and at the hearing regarding the rationale for this investment, which was made pursuant to the Mountain Energy Act and which the Commission found was needed in Docket No. E-2, Sub 1089. As discussed elsewhere in this Order, the Asheville CC Project is complete, placed in service, and available for economic dispatch. Further, no party has offered concrete, specific evidence to contradict DEP's determination that it needed to continue to operate these units to serve customers or has met the burden of production to challenge the Company's specific coal fleet investments.

Sierra Club witness Wilson's recommended disallowance, as she admitted, is not specific to any particular cost, neither does Sierra Club offer any prudent alternative that DEP could have chosen. Witness Wilson admitted that retiring the coal fleet all at once would likely result in reliability issues yet did not identify any other alternatives available to the Company. Regarding NC WARN's recommendation, other than the Asheville CC Project in general, witness Powers did not identify any specific costs as being imprudently incurred. In addition, the alternatives suggested by NC WARN – merchant generation purchases, solar plus storage, and hydroelectric generation – are not supported by any evidence suggesting that these were feasible options for the Company. No witness conducted an independent analysis using the information available at the time the Company's investment decisions were made to present evidence supporting a finding that DEP could have made another prudent choice. The evidence instead demonstrates that the Company made the best investment decisions it could with the information available at the time.

Moreover, the Commission finds persuasive witness Turner's rebuttal of witness Wilson's economic value analysis, which did not consider either the capacity value provided by DEP's coal fleet or how the Company dispatches its system as a whole on a daily basis. Isolating costs invested in and the value of energy produced by a particular station on an annual basis does not accurately represent the value of the coal fleet. As witness Turner testified, even units with declining capacity factors are still needed during times of high demand. For similar reasons, and because DEP must still invest in a unit to keep it available during high demand periods, the Commission does not find witness Wilson's recommendation that the Company consider operating its units seasonally to be reasonable. Finally, the Commission does not accept witness Wilson's interpretation of the term "useful" in the used and useful standard. Her reading contemplates finding an asset not to be useful when it was planned prudently and was impacted by changes outside the utility's control, which is not an interpretation that has been adopted by this Commission.

Witness Wilson quantified her disallowance recommendation on the contention that DEP did not present evidence of the value of the investments at the time they were made. However, as witness Wilson's hearing testimony made clear, she ignored evidence in the form of the 2016 Mayo Station retirement study pertaining directly to this issue. As shown by witness Turner's testimony, the Company conducted an exhaustive study of continued investments in Mayo Station, as well as economic analyses of other coal fleet investments, and relied on the results of those studies to proceed with the investments it is seeking to recover. The Commission therefore concludes that Sierra Club's assertion regarding a lack of evidence is not supported by the record.

The Commission also declines to accept witness Wilson's recommendation to limit the Company's future investments in its coal fleet. Such a limitation is not necessary as the Company is not able to recover any future capital investments before seeking and obtaining the Commission's approval in a future proceeding. Further, as witness Wilson recognized, North Carolina uses a historical test year as the basis for evaluating just and reasonable rates, which is not consistent with a prospective limit on capital expenditures.

Finally, no party recommended any disallowance of the Company's request for recovery of its capital investments in its nuclear fleet based on unreasonableness or imprudence. As a result, and based on the uncontroverted testimony and the record, the Commission finds and concludes that the costs associated with the Company's investments in its nuclear generating fleet were reasonably and prudently incurred and should be recovered.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 15-23

CCR Cost Recovery

The evidence supporting these findings of fact is found in the verified Application, and Form E-1; the CCR Settlement; the testimony and exhibits of the expert witnesses in both the present rate case and the 2018 DEP rate case, including the testimony and exhibits of DEP witnesses De May, Bednarcik, Wells, Williams, Bonaparte, Lioy, Doss, Riley, Spanos, and Fetter, Public Staff witnesses Lucas, Maness, Garrett, and Moore, AGO witness Hart, Sierra Club witness Quarles, and CUCA witness O'Donnell; and the entire record in this proceeding.

Summary of the Evidence

DEP Direct Testimony

Witness Bednarcik

Witness Bednarcik provided an overview of the federal and state regulatory requirements applicable to DEP's coal ash basins and landfills, including the CCR Rule and CAMA. Witness Bednarcik testified that all of the coal ash remediation actions taken by DEP for which it is seeking cost recovery were required by applicable statutes and regulations and were performed in a prudent and reasonable manner. Tr. vol. 12, 31-33.

Witness Bednarcik explained the closure options available for the Company's low-risk impoundments, including the Company's original plans to close those basins by cap-in-place. With assistance from experienced, professional engineering firms, the Company developed and submitted Closure Options Analysis Reports (COA Reports) to DEQ in fourth quarter of 2018 for the four sites. *Id.* at 37-41. On April 1, 2019, DEQ ordered Duke Energy to excavate all remaining coal ash impoundments in North Carolina, including the low risk impoundments at Mayo and Roxboro. *Id.* at 42. With the exception of preliminary closure plan development, the Company had not begun implementing cap-in-place closure at any of the sites covered by the order. *Id.* Next, witness Bednarcik discussed the unique closure activities that the Company has undertaken at each of its sites, itemizing the associated costs thru June 2019 related to compliance and closure of its CCR basins: Mayo ($22,520,499), Roxboro ($16,845,265), Asheville ($99,274,167), Sutton ($102,560,125), Cape Fear ($41,690,655), H.F. Lee ($86,609,666), Weatherspoon ($25,674,837), and Robinson ($20,762,298). *Id.* at 45-50, 54-55.

In Witness Bednarcik further testified that in 2014 Duke Energy executed contracts with Charah, LLC (Charah), to dispose of coal ash from DEC's Riverbend plant and DEP's Sutton, Cape Fear, H.F. Lee, and Weatherspoon plants. She stated that the contracts required Duke to provide a minimum amount of coal ash and that due to changing circumstances caused by CAMA amendments, Duke did not provide the minimum amount of coal ash to Charah. *Id.* at 51-52. As a result, Duke incurred a fulfillment charge of $80 million, of which $33,670,054 had been allocated to DEP. Witness Bednarcik testified that the Company could not have foreseen the CAMA amendment, and therefore acted reasonably and prudently when it executed the Charah contract, thereby authorizing it to acquire the necessary mines and develop infrastructure needed to transport and store the Company's coal ash.

Public Staff

Witness Lucas

Public Staff witness Lucas discussed in his testimony[2] a set of historical documents that he testified showed "an evolving body of scientific knowledge over more than 50 years concerning the risks of environmental contamination resulting from storing coal ash in unlined impoundments, and alternative methods of coal ash management." Tr. vol. 15, 1477-78. According to witness Lucas these documents demonstrated that, "by the early 1980s, the electric generating industry knew or should have known that the wet storage of CCR in unlined surface impoundments posed a serious risk to the quality of surrounding groundwater and surface water." *Id.* at 1478. He argued that given the state of knowledge at the time, "DEP should have installed comprehensive groundwater monitoring well networks in the 1980s to determine if the risk was materializing." *Id.* at 1480-81. Witness Lucas testified that DEP has accumulated significant environmental

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[2] The live testimony of witnesses Bednarcik, Wells, Williams, Hart, Quarles, Wilson, Garrett, Moore, Riley, Junis, and Maness in Docket No. E-7, Sub 1214 was copied into the record in the current docket as if given orally from the stand, pursuant to the September 28, 2020 Amended Joint Stipulation Regarding Admission of Certain Live Testimony and Exhibits (Amended Stipulation) entered into by DEP, the Public Staff, the Attorney General's Office, and the Sierra Club. The Amended Stipulation stated the following: "The Stipulating Parties recognize that Public Staff witness Junis appeared in the DE Carolinas case, but is not appearing in the DE Progress case, and that his place in the DE Progress case is being assumed by Public Staff witness Jay Lucas. Accordingly, in this instance, the "same" witness as Charles Junis in the DE Progress case is understood to be Public Staff witness Lucas." Amended Stipulation at 3, n 2. Therefore, during the hearing, witness Lucas adopted the live testimony of Public Staff witness Junis in Docket No. E-7, Sub 1214, and witness Maness' live testimony in Docket No. E-7, Sub 1214 was likewise copied into the record. Tr. vol. 15, 1633-34. Citations in this Order to Tr. vol. 15, pages 1639-1817 reference the stipulated live testimony from Docket No. E-7, Sub 1214 of witnesses Junis and Maness.

violations associated with its coal ash impoundments, including unauthorized seeps in violation of its NPDES permits and 7,411 groundwater exceedances in violation of the state's 2L rules. Regarding seeps, he explained that while almost all earthen dams have seeps, DEP's dams impound coal ash wastewater, which cannot be lawfully discharged without a permit. *Id.* at 1485-88. He also explained that "engineered" or "constructed" seeps are those that were deliberately constructed. *Id.* at 1485. Witness Lucas described Special Orders by Consent (SOCs) entered into between DEP and DEQ for seeps at the Asheville, Cape Fear, H.F. Lee, Mayo, Roxboro, and Weatherspoon plants.

Witness Lucas testified that the deliberately constructed seeps have been included in the Company's renewed or modified NPDES permits but argued that including these seeps in DEP's permits "does not retroactively condone them." *Id.* at 1487. Witness Lucas stated that despite the knowledge that groundwater monitoring is "necessary to provide convincing proof of a safe disposal practice," DEP did not begin groundwater monitoring at some of its facilities until decades later. *Id*. at 1491-92. Witness Lucas testified that it is notable that the Company's number of groundwater standard violations has increased by 4,554, or 159%, since his testimony in the last DEP rate case. *Id*. at 1508.

Witness Lucas argued that while the Company calls such costs "compliance costs" for meeting the requirements of CAMA and the CCR Rule, "they also reflect DEP's non-compliance with longstanding environmental regulations." *Id*. at 1494. Witness Lucas opined that the evidence shows DEP would have incurred substantial corrective action costs under the state's 2L rules even in the absence of CAMA and the CCR Rule. . He stated, however, that there were instances in which DEP's actions were prudent, that separating out the imprudent costs would be complex, and that the calculation of some costs of imprudence would be speculative. *Id*. at 1506-08, 1821-23. Witness Lucas concluded that "[d]ue to its environmental violations, DEP has a great deal of culpability for the compliance costs related to remediation and ash basin and storage unit closures, and would likely have incurred substantial coal ash corrective action costs even without the CCR Rule and CAMA, whereas ratepayers are not culpable at all for those costs." *Id*. at 1510. Therefore the Public Staff recommended an equitable sharing, with 50% of the CCR costs being paid by shareholders and 50% by ratepayers. *See also id*. at 1761-62.

Witness Lucas summarized the details of the 2019 Settlement Agreement, reached by DEC, DEP, DEQ, and several environmental parties, which addressed CCR impoundments at DEP's Mayo and Roxboro plants and DEC's Allen, Belews Creek, Cliffside, and Marshall plants, and which, among other things requires Duke Energy to excavate a majority of the coal ash and place it in a lined landfill. The 2019 Settlement Agreement also indicated some relief for the closure deadlines for the Buck, H.F. Lee, and Cape Fear plants.

Witness Lucas also testified that the Public Staff's recommended disallowance of the costs to provide bottled water, water connections to municipal or county systems, and water treatment systems; for the period of September 2017 through December 2019, the costs amounted to $395,005, $1,087,612, and 2,774,583, respectively, on a system basis. Tr. vol. 15, 1503-05. In his supplemental testimony, witness Lucas updated the

Public Staff's position to include the costs of municipal water supplies and water filtration systems that the Company incurred in January and February 2020. *Id.* at 1529-30.

Witnesses Garrett and Moore

Witnesses Garrett and Moore, each principals in and founding members of Garrett & Moore, Inc., which provides environmental engineering and consulting services to power and waste industries, proposed three distinct prudence-based disallowances to the Company's CCR costs.

First, witness Garrett proposed a disallowance of $33,670,054 which represented DEP's allocation of the fulfillment fee the Company paid to Charah related to the disposal of ash from the Sutton, Cape Fear, H.F. Lee, and Weatherspoon plants at the Brickhaven structural fill site. Tr. vol. 15, 1222, 1235-36. Witness Garrett also testified that he believed any consideration of fees paid for land acquisition at the Sanford Mine pursuant to the Charah Master Contract should be excluded because no ash was ever transferred from any DEP site to the Sanford mine. *Id.* at 1236.

Second, witness Garrett proposed a disallowance of $50,238,630 related to the hauling costs for disposal of ash from the Asheville plant to the R&B landfill in Homer, Georgia. *Id.* at 1222, 1252. In support of his recommended disallowance, he argued that there were two lower cost alternatives to disposal at the R&B landfill: (1) transportation of ash to Cliffside; and (2) depositing ash in an onsite landfill. *See also id.* at 1261-62.

Third, witness Moore proposed a disallowance of $130,348,392, representing a portion of the costs related to the beneficiation units at the H.F. Lee and Cape Fear sites. *Id.* at 1183. Specifically, witness Moore testified that the costs incurred by subcontractor Zachry Industrial Inc. (Zachry) for Engineering, Procurement, and Construction (EPC) at the Cape Fear and H.F. Lee beneficiation sites were not reasonable and prudent because they were higher than the estimate for each project that was included in contractor The SEFA Group, Inc.'s (SEFA) response to the Company's Request for Information (RFI). *Id*. at 1195. Witness Moore testified to many other steps that the Company should have taken to mitigate the high cost, including re-bidding the contract, entering into three separate construction contracts, obtaining an amendment to CAMA, or obtaining guidance from DEQ. *Id.* at 1205-06.

Witnesses Garrett and Moore otherwise testified that they found the Company's requested recovery for CCR costs incurred at the Mayo, Roxboro, Sutton, and Robinson plants to be reasonably and prudently incurred. *Id*. at 1184-85,1264-65.

Witness Maness

Witness Maness discussed the three coal ash cost adjustments being proposed by the Public Staff: (1) the disallowances recommended by witnesses Lucas, Moore and Garrett; (2) an amortization period of 25 years; and (3) the reversal of DEP's inclusion of coal ash costs in rate base.

Witness Maness testified that the Public Staff believes there should be an equitable sharing of the coal ash costs between ratepayers and shareholders. Tr. vol. 15, 1560-65, 1579. He explained that an equitable sharing can be achieved by, first, excluding the coal ash costs from inclusion in DEP's rate base and, second, using a longer amortization period. Witness Maness testified that the five-year amortization period proposed by DEP is too short. He stated that the CCRs are the result of decades of generating electricity by coal and that associated costs should be amortized over a similarly lengthy period. The Public Staff, therefore, recommends an amortization period of 25 years. *Id.* at 1560-61, 1627. Witness Maness also gave several reasons why, independent of culpability, the magnitude and general nature of the CCR costs in this case justified equitable sharing. *Id.* at 1563-65.

With respect to DEP's future coal ash costs, witness Maness testified that the Public Staff agrees that DEP should be allowed to defer its future costs in a regulatory asset and accrue a return on the deferred balance at the net-of-tax overall return authorized by the Commission for DEP during the deferral period. *Id*. at 1587-89.

AGO

AGO Witness Hart

In the current rate case witness Hart discussed the CCR Rule, CAMA, the 2L rules, and other environmental guidelines applicable to coal ash basins. Witness Hart testified that unlined coal ash basins cause groundwater contamination. Tr. vol. 13, 570-72. He explained that the metals present in the coal ash leach out of the ash, enter a dissolved state, and become coal ash "leachate," and that because a hydraulic head is maintained in the basin the metals-laden water in the basin migrates downward into underlying soil. *Id*. at 575-86. Witness Hart discussed several industry and government studies and reports, similar to those noted by other witnesses, *see id.* at 588-602, that he opined placed the electric utility industry on notice of the potential leaching of coal ash metals into groundwater.

Witness Hart provided the details of the coal ash basins and groundwater monitoring at each of DEP's coal plants. In addition, he included graphs for each plant showing the most prominent coal ash constituents. *Id*. at 624-85. Witness Hart concluded that prior to the Dan River coal ash spill DEP did not take reasonable and prudent actions to address groundwater contamination at its coal ash basins and to close the basins. *Id.* at 685-93. Witness Hart testified that DEC's inaction increased its present coal ash remediation costs because the Dan River spill prompted accelerated remediation actions, which are always more costly. Witness Hart stated that earlier prudent action by DEP would have resulted in cost recovery while the coal plants were still in use, and beginning in 1992, 1996, or 2009, DEP's system coal ash closure costs would have been reduced by $291 million, $275 million, or $218 million, respectively. *Id.* at 693-703.

Sierra Club

Witness Quarles

Sierra Club witness Mark Quarles previously testified in Sub 1142 about coal ash and evaluated the methods by which DEP proposed to close existing CCR surface impoundments in-place by leaving wastes in existing disposal areas (i.e., “closure-in-place”) at its Mayo and Roxboro coal plants. That testimony evaluated whether and opined that the Company could not meet the closure-in-place performance standards established by EPA in its CCR Rule due to site characteristics and hydrogeologic conditions at the Mayo and Roxboro sites, and that groundwater contamination would continue into the foreseeable future.

In the current rate case witness Quarles focused in his testimony on “determining *when* the Company knew or should have known that groundwater or surface water contamination was likely due to storage and disposal of CCRs in unlined areas located near — and even sometimes within — rivers and streams and where the ash is saturated with groundwater.” Tr. vol. 12, 591. Witness Quarles also concluded that DEP’s total coal ash clean-up costs could have been lower if the Company had switched to dry disposal in lined landfills sooner and testified that the risks of groundwater contamination from unlined coal ash ponds were understood as early as the late 1970s. *Id.* at 594.

Witness Quarles testified to the history of DEP’s use of unlined ponds at each plant, noting that DEP constructed surface impoundments from the 1950s through 1980s and expanded some as recently as 2001 (Weatherspoon) and 2002 (Robinson). Witness Quarles also testified that DEP began “required” groundwater monitoring at Sutton in 1984, Roxboro in 1986, and Weatherspoon in 1989. The earliest instances of “voluntary” monitoring were at Cape Fear and H.F. Lee in 2007 and Mayo in 2008. Some of these sites went unmonitored for over 50 years. Witness Quarles opined that this decades-long operation without monitoring was unreasonable, given the known risks and that the Company itself knew of leaching at Sutton in the early 1980s. *Id.* at 606.

In addition to DEP’s knowledge of the leaching at Sutton, Witness Quarles pointed to several other records which showed the Company investigated potential groundwater contamination as early as the 1970s, including a groundwater study at Sutton which concluded that the new basin should be built with a liner and a 1979 study of the Mayo site which evaluated the geologic and hydrologic conditions; that study concluded that “at least a one-foot layer of clay beneath the proposed pond was necessary to protect groundwater, but even with such clay lining, not all metals would be filtered, and the duration of the filtering would be limited.” *Id.* at 607-08. Witness Quarles also noted that DEP itself concluded in 2014 that its “coal ash is impacting groundwater at all locations” and that groundwater protection standards had been exceeded for each site for one or more of the following: arsenic, cobalt, lithium, molybdenum, selenium, thallium, and total radium, with migration off-site at several of the sites. *Id.* at 612. “[R]ather than initiating corrective actions to eliminate or mitigate the contamination, Duke Energy companies have responded by purchasing affected properties or providing alternative drinking water sources" including at Sutton and H.F. Lee. *Id.*

For these and other reasons witness Quarles recommended that the Commission conclude that DEP's continued operation of unlined basins after the industry recognized the risks, that operation of unlined coal ash basin after the 1980s, and that the Company's failure to operate adequate groundwater monitoring around its disposal areas until the 2000s, were each unreasonable.

CUCA

Witness O'Donnell

Witness O'Donnell contended that Duke management's specific decisions caused the Dan River spill and cited an early draft of CAMA and statements by legislators to support his contention that Duke's environmental violations caused the General Assembly to enact CAMA, and, therefore, DEP should not be permitted to recover from customers any coal ash costs above those that DEP would have incurred under the CCR Rule. Tr. vol. 14, 168-79.

DEP Rebuttal Testimony

Witness Bednarcik

Witness Bednarcik responded to the Public Staff's recommended 50/50 equitable sharing disallowance, pointing out that the recommendation is not tied to any finding of unreasonableness or imprudence but to culpability for environmental degradation requiring expensive remediation and the enormity of the costs. Tr. vol. 17, 136. She noted Public Staff witness Lucas' admission of the impossibility of conducting a prudency audit of the Company's historical CCR activities, and she stated that the Commission has rejected this equitable sharing approach three times. *Id*. at 137-38.

Witness Bednarcik also responded to the contentions of witnesses Lucas, Hart, and Quarles that the Company's CCR practices lagged behind those of industry, contending that the Company's historical CCR practices were in line with those of industry and similarly situated utilities in neighboring states. *Id.* at 138. In response to the historical documents cited by witnesses Lucas, Hart, and Quarles, witness Bednarcik argued that this "small handful of papers" would not have given a utility adequate reason to change its CCR practices. *Id.* Witness Bednarcik also stated that the intervenor witnesses were viewing these issues "through the filter of a 21st century lens when no such clarity existed in real time." *Id*. at 138-39. Witness Bednarcik also challenged the recoverability of the costs to build new lined impoundments to retire existing coal ash impoundments before the enactment of the CCR Rule and CAMA. *Id.* at 140-43.

Witness Bednarcik addressed the recommended disallowance of AGO witness Hart, arguing against his suggestion that the Company could have reduced costs by beginning closure at an earlier date. Witness Bednarcik stated that it was impossible to predict with any certainty what type of approach DEP would have pursued historically with respect to its coal ash basins given the then-existing regulatory landscape, available technology, evolving industry best practices, and other factors. *Id.* at 142-45. Witness Bednarcik also testified that DEQ instructed DEP as late as 2009 that initiating closure of inactive basins was not necessary. *Id.* at 143-45.

Witness Bednarcik also discussed and rebutted the specific prudence-based and culpability-based disallowances recommended by the Public Staff and AG, including: (1) payment of the fulfillment fee to Charah ($36,670,054), *id.* at 87-89, 92-99; (2) payment of a purported $30.42 per ton cost to transport CCR from the Asheville plant to the R&B landfill in Homer, Georgia ($50,238,630), *id.* at 104-06, 113-16; (3) construction costs at the H.F. Lee and Cape Fear Beneficiation plants ($130,384,392), *id.* at 116-28; (4) expenditures for groundwater extraction and treatment at the Asheville and Sutton plants, as well as the purchase of land at the Mayo plant which allowed the Company to mitigate potential exposure pathways ($1,240,328 on a system basis), *id.* at 132-33; and (5) costs incurred to connect eligible residential properties to permanent water supplies or install and maintain water treatment systems as required by CAMA. *Id.* at 144-45.

Witness Bednarcik also filed supplemental testimony responding to the Commission's July 23, 2020 Order Requiring Duke Energy Carolinas, LLC and Duke Energy Progress, LLC to File Additional Testimony on Grid Improvement Plans and Coal Combustion Residual Costs. Witness Bednarcik discussed the Settlement Agreement the Company reached with DEQ and environmental groups on December 31, 2019, as well as the Company's estimate of the future costs of excavating, rather than capping-in-place, remaining ash at the Company's designated "low-risk" CCR impoundments. *Id.* at 148-55.

Witnesses Wells and Williams

Witnesses Wells and Williams argued that there were flaws in intervenors' theories, namely that they: (1) applied modern environmental standards to historical practices, (2) ignored the discretion afforded to the Company's environmental regulators, and (3) cherry-picked data points to draw unreasonable inferences regarding the Company's knowledge or actions, also dismissing scientific conclusions and regulatory *decisions* that did not fit their narrative. *See* Tr. vol. 19, 140. Witnesses Wells and Williams, together, provided a Company-specific, overall industry, and historical regulatory perspective of coal ash management practices over the past five decades.

Witness Williams, who worked for the EPA for 17 years and served as Director of the Office of Solid Waste until 1988, testified in depth regarding the history of coal ash regulations and the evolution of the CCR Rule. *Id.* at 205-12. She stated that owners and operators of coal ash basins in North Carolina faced significant uncertainty regarding regulatory requirements until adoption of the CCR Rule and CAMA, and based on these uncertainties, owners and operators of coal ash basins acted prudently by waiting for adoption of the CCR Rule and CAMA to take specific actions to upgrade or close coal ash basins. She discussed several factors that compound uncertainty in EPA regulation, and she opined that DEP did not act imprudently by waiting for regulatory clarity so long as it continued to work with regulatory agencies to address site specific environmental risks.

Witness Williams explained that DEP's initial construction and continued use of unlined ash basins even after 2014 was consistent with industry standards and applicable federal and state environmental regulations. Even as late as 2010, when EPA proposed its CCR Rule, witness Williams testified that according to EPA, 74% of existing units were unlined, and 40% of "new" (meaning constructed during the 1990s or thereafter) units were unlined. *Id.* at 422. Witness Wells also explained that DEP's environmental regulators issued permits to DEP which specifically authorized the Company to sluice fly ash and bottom ash to unlined basins and then discharge the sluice water to surface waters after settling occurred. *Id.* at 141-42. He testified that neither the utility industry nor environmental regulators believed that unlined basins posed significant environmental risk, and therefore discontinuing use of unlined impoundments during their useful life was neither prohibited nor even discouraged. *Id.* at 144.

Witness Wells testified that studies performed by EPA, the industry, and DEP in the late 1970s and throughout the 1980s that were applicable to DEP's ash basins consistently demonstrated that harm to groundwater quality from its unlined impoundments was nonexistent or insignificant. *Id.* at 144-45. He stated that even today, groundwater and surface water monitoring has demonstrated that DEP's ash basins have not caused significant harm to the environment or public health. *Id.* at 388. Witnesses Wells and Williams further testified that these studies culminated in EPA's 1988 Report to Congress, which concluded "that current waste management practices [including unlined ash basins] appear to be adequate for protection of human health and the environment." *Id.* at 162, 223.

Witness Wells testified in detail about the Company's implementation of groundwater monitoring at its Sutton plant in the 1980s and its Weatherspoon plant in the 1990s. *Id.* at 152-58, 162. In addition, he testified that DEP also began monitoring groundwater at Roxboro in conjunction with its construction of an ash landfill. Later in the mid-2000s, DEP voluntarily participated in the USWAG Action Plan, which resulted in monitoring networks being developed at all of its sites. He stated that it was not until 2010 that DEQ required DEP to monitor groundwater at all of its sites. *Id*. at 165. Witness Williams testified that DEP's groundwater monitoring efforts over time reveal a company that was "way ahead" of the industry as a whole. *Id.* at 361.

Regarding seeps, witness Wells asserted that the existence of seeps at ash basins is not evidence that the ash basins were mismanaged. He stated that DEQ was long aware of the existence of seeps but that DEQ exercised regulatory restraint and did not view them as a priority for inclusion of NPDES permits due to the low concentrations of constituents. *Id.* at 186. Witness Wells also faulted witness Lucas for relying on the "new" exceedances since the last rate case, explaining that there were flaws in the Public Staff's analysis. *Id.* at 190-93.

In sum, witnesses Wells and Williams testified that witnesses Lucas, Quarles, and Hart each failed to consider all relevant information, including selectively using information from studies and reports without considering the broader set of available knowledge on the subject, did not give appropriate weight to environmental regulations, and failed to assess in detail industry practices in CCR and other waste management. Further, witness Williams asserted that they also failed to give appropriate weight to the role of DEQ in overseeing DEP's actions. *Id.* at 321-24. Given the Company's forthcoming and cooperative relationship with its regulators, witnesses Wells and Williams concluded that it was unreasonable and unfair for intervenors to cast DEP's CCR management practices in a negative light. *See also id.* at 347-51.

Witness Bonaparte

Witness Bonaparte testified about his observations and findings regarding CCR management strategies and closure planning of CCR surface impoundments in the Southeast region where DEP operates, including the states of Georgia, North Carolina, South Carolina, and Virginia. Tr. vol. 11, 119-20. He summarized:

- Information was reviewed for 93 CCR impoundments at the 40 generating stations. Of these, only three (3.2%) CCR impoundments were identified as having engineered closure plans and/or engineering-related closure planning in the 2009-2011 timeframe, or earlier. A few additional impoundments had received a layer of non-engineered fill above the CCR impoundment or had vegetation growing on the surface of the impoundment.

- Of the 93 CCR impoundments reviewed, 85 (91%) were either directly reported or interpreted as being unlined; most of the CCR impoundments reviewed were reported as being active in the 2009-2011 timeframe; and of the active impoundments the majority were reported as receiving sluiced CCR at the time of the USEPA dam safety assessment reports.

- Only 1 of the 57 CCR Rule closure plans had any indication of closure planning for the subject CCR impoundment for the 2009-2011 timeframe, or earlier.

Id. at 121; DEP Bonaparte Rebuttal Ex. 2 at 9.

Witness Lioy

Witness Lioy challenged AGO witness Hart's methodology from an accounting perspective as flawed and unreliable, including witness Hart's misunderstanding of the "time value of money" concept. *Id.* at 157-64. Witness Lioy also testified that witness Hart failed to consider a number of necessary factors that he would need to determine what DEP would have spent in 1992, 1996, or 2009. *Id.* at 165.

Setting aside witness Hart's misapplication of the time value of money concept, witness Lioy also opined that witness Hart made numerous other errors that render his testimony unreliable. Witness Lioy testified that AGO witness Hart failed to consider a number of factors in his attempt to quantify the amount that DEP would have spent as of the earlier time periods in his analysis (1992, 1996, or 2009) in order to quantify alleged imprudently incurred costs. *Id.* at 165-67. Witness Lioy also concluded that witness Hart's calculations were not prepared in accordance with normal conventions and are unreliable and speculative. *Id.*

Witnesses Doss, Spanos, and Riley

Witness Doss testified that the Company opposes the Public Staff's equitable sharing proposal and witness Maness's recommendations to lengthen the amortization for CCR cost recovery and disallow a return during the amortization period. Witness Doss did not agree with witness Maness's characterization of coal ash ARO related costs as deferred expenses. Tr. vol. 16, 340-41. Witness Doss further disagreed with witness Maness's assertion that the Company can choose whether it will defer coal ash ARO-related costs. *Id.* at 363-65; Tr. vol. 17, 45-46. Lastly, witness Doss disagreed with witness Maness's argument that coal ash ARO costs are not characteristic of assets recorded as used and useful property, arguing instead that the costs incurred (relating to the deferred depreciation and accretion) are used and useful as those costs are reasonable and prudently incurred and are intended to provide utility service in the present or in the future through achieving their intended purpose: environmental compliance, the retirement of the ash impoundments and the final storage location for the residuals from the generation of electricity. Tr. vol. 16, 344.

Witness Riley provided testimony on two FASB codified GAAP standards applicable to the Company: ASC 980 and ASC 410. According to witness Riley, ASC 980 addresses requirements specific to regulated entities. In so doing, it provides a linkage between costs and revenues that does not exist for nonregulated companies, and also places a primary emphasis on regulatory ratemaking in the determination of appropriate accounting treatment.

Witness Riley also discussed the requirements of ASC 410, which beginning in 2003 required companies like DEP to assess whether it had a present legal obligation to remove, dispense, or remediate a long-lived capital asset. Tr. vol. 13, 354. Witness Riley noted that receiving less than a full return (which would be at the Company's weighted average cost of capital) would constitute a cost disallowance. *Id.* at 404-06. Witness Riley also provided testimony on the manner in which CCR removal costs are accounted for in depreciation studies. He opined that it was not general industry practice to include those costs in depreciation studies prior to the EPA's adoption of its CCR Rule.

DEP Settlement Testimony

Witness De May

In support of the January 25, 2021 CCR Settlement witness De May testified that the CCR Settlement represents a balanced solution that resolves the coal ash cost recovery debate in North Carolina, providing both immediate and long-term savings for customers and long-term certainty for the Company and its investors and allowing all parties to move forward towards the desired cleaner energy future. He concluded that the CCR Settlement is in the public interest and should be approved.

Witness De May provided an overview of the CCR Settlement. He testified that it resolves among the CCR Settling Parties, subject to Commission approval, CCR cost recovery issues in both DEP's and DEC's current rate cases and the Companies' prior cases in a comprehensive manner for the period beginning January 1, 2015 (when the Company first incurred such costs) through February 28, 2030 — a period of over fifteen years. Witness De May contended that the CCR Settlement requires the Company to reduce the amount of coal ash-related costs to be recovered from customers and grants the Company the ability to earn a return upon the recovered costs at a negotiated cost of equity lower than the Company's allowed ROE. The CCR Settlement also provides customers with immediate and future rate reduction — DEP and DEC together will absorb approximately $1.1 billion (on a North Carolina system basis) through February 2030. Witness De May testified that on a North Carolina retail basis, the net present value of the cost savings to customers (including applicable financing costs) is in excess of $900 million. Importantly, witness De May noted, a large portion of the rate reduction will occur over the near term, during a period in which many customers are suffering severe economic hardship from the COVID-19 pandemic.

Witness De May also summarized the benefits of the CCR Settlement to the Company. He explained that it "validates and affirms the reasonableness and prudence of [each] Company's ash basin closure strategy," provides more certainty and stability regarding cost recovery, and — by preserving the Companies' ability to recover financing costs, albeit at a reduced rate — preserves their access to much needed capital on reasonable terms, also benefitting customers. Finally, the CCR Settlement — in settling the legacy issue — allows the collective focus to shift to the future to cleaner sources of energy, while maintaining the Company's drive to keep electricity affordable and reliable.

Witness De May explained that the CCR Settlement appropriately balances the need for rate relief with the impact of such rate relief on customers. He stated that the Company is pleased that its rates are competitive and below the national average and will remain so under the CCR Settlement, noting that providing safe, reliable, and increasingly clean electricity at competitive rates is key. Witness De May stated that, particularly in light of the current economic conditions faced by customers due to the COVID-19 pandemic, the Company believes the CCR Settlement fairly balances the needs of customers with the Company's need to recover substantial investments made to continue to comply with regulatory requirements and safely provide high quality electric service. And he concluded that given the size of the necessary capital and compliance expenditures the Company faces it is essential that DEP maintain its financial strength and credit quality for the benefit of its customers.

Witness Smith

Witness Smith similarly testified that the Company believes that the CCR Settlement represents a fair, just and reasonable, and balanced solution that provides immediate and long-term savings for customers as well as the long-term certainty the Company and its investors need. Thus, the Company requests that the Commission approve of the CCR Settlement in its entirety. The effect of the CCR Settlement on the Company's requested recovery of CCR costs is shown on Smith CCR Settlement Exhibit 1, page NC-1102CA. As set forth therein, the CCR Settlement provides for DEP to recover $138,134,625 of actual coal ash basin closure and compliance costs plus financing costs of $53,443,112.

Witness Smith testified that, if the Commission approves the CCR Settlement and the First and Second Partial Stipulations with the Public Staff, the Company's revised request for a revenue increase in base rates is reduced to $344 million. She explained that Smith CCR Settlement Agreement Exhibit 2 showed that the Company's revised request for a revenue increase, combined with the Company's request to reduce customer rates by $137 million through its two proposed EDIT riders and the RAL-1 rider, results in a net proposed increase in revenue of $207 million — a $257 million reduction from the amount proposed in the Company's Application. She further noted that these amounts assume the Commission accepts the Company's position on the remaining unsettled revenue issues, mainly depreciation rates. The other nonrevenue issues concern various forward-looking studies and rate designs.

Public Staff Settlement Testimony

Witness Maness

Witness Maness testified that the CCR Settlement would comprehensively resolve the following CCR cost recovery issues: (1) issues pending before the Commission on remand in the 2018 Rate Cases; (2) issues pending before the Commission in the present rate case proceedings; (3) the treatment of CCR costs incurred by DEC from February 1, 2020, through January 31, 2030, and by DEP from March 1, 2020, through February 28, 2030, along with associated financing costs; and (4) how any proceeds received from insurance litigation related to CCR costs would be shared by ratepayers, DEC, and DEP.

In addition, witness Maness explained that from the perspective of the Public Staff, the most important ratepayer benefits of the CCR Settlement are: (1) DEC's and DEP's agreement to forego the combined recovery of CCR costs and associated financing costs in excess of $900 million, on a present value basis, resulting in a significant reduction in the proposed revenue increase in this case; (2) the allocation of the proceeds of CCR insurance litigation; and (3) the avoidance of protracted litigation over CCR costs and financing costs into 2030. Accordingly, witness Maness stated that the Public Staff believes the CCR Settlement is in the public interest and should be approved.

Witness Boswell

Witness Boswell provided updated schedules showing the impact of the CCR Settlement. She noted that some final adjustments will have to be made after the Commission's issues its order resolving the remaining unsettled issues.

Public Witness Testimony and Consumer Statements of Position

Over the course of the five public witness hearings held in the instant case, during which a total of 58 public witnesses provided testimony to the Commission, many of the witnesses expressed concerns to the Commission regarding the environmental impact of, the handling of, and the costs associated with CCRs.[3] Similarly, many of the written consumer statements of position filed in this proceeding addressed the issues of the environmental impact of, the handling of, and the costs associated with CCRs.

Discussion and Conclusions

The Commission is required to set just and reasonable rates for public utilities. N.C.G.S. § 62-130(a). Just and reasonable rates are those that provide the utility an opportunity to earn a fair return on its property and are fair to the utility's customers. *State ex rel. Utils. Comm'n v. Piedmont Nat. Gas Co.*, 254 N.C. 536, 119 S.E.2d 469 (1961); *State ex rel. Utils. Comm'n v. Duke Power Co*., 285 N.C. 377, 206 S.E.2d 269 (1974). To achieve just and reasonable rates, the utility's revenue must be sufficient to cover the utility's cost of service, plus allow the utility the opportunity to earn a reasonable return on its rate base but must be fair to customers. To this end, the North Carolina Supreme Court has counseled:

> [T]he fixing of "reasonable and just" rates involves a balancing of shareholder and consumer interests. The Commission must therefore set rates which will protect both the right of the public utility to earn a fair rate of return for its shareholders and ensure its financial integrity, while also protecting the right of the utility's intrastate customers to pay a retail rate which reasonably and fairly reflects the cost of service rendered on their behalf.

State ex rel. Utils. Comm'n v. Nantahala Power & Light Co., 313 N.C. 614, 691, 332 S.E.2d 397, 474 (1985), *rev'd on other grounds*, 476 U.S. 953, 90 L.Ed.2d 943 (1986), *appeal after remand*, 324 N.C. 478, 380 S.E.2d 112 (1989) (*Nantahala*).

The burden of proof to show that rates are just and reasonable is on the utility. N.C.G.S. § 62-134(c). However, according to the North Carolina Supreme Court,

> [i]n spite of the fact that North Carolina utilities have the burden of proving that the costs upon which their rates are based are reasonable and prudent,

[3] Raleigh (14/16 witnesses), Wilmington (13/14), Snow Hill (3/5), and Asheville (12/23). No public witnesses appeared at the hearing conducted in Rockingham.

> the reasonableness and prudence of those costs is "presumed" unless the Commission or an intervenor adduces sufficient evidence to cast doubt upon their reasonableness or prudence, at which point the burden to make an affirmative showing of the reasonableness of the costs in question shifts to the utility. *State ex rel. Utils. Comm'n v. Intervenor Residents of Bent Creek/Mt. Carmel Subdivisions*, 305 N.C. 62, 76, 286 S.E.2d 770, 779 (1982) (*Bent Creek*). In order to satisfy this burden of production, an intervenor must offer affirmative evidence tending to show that the expenses that the utility seeks to recover "are exorbitant, unnecessary, wasteful, extravagant, or incurred in abuse of discretion or in bad faith or that such expenses exceed either the cost of the same or similar goods or services on the open market or the cost similar utilities pay to their affiliated [utilities] for the same or similar goods or services." *Id.* at 76–77, 286 S.E.2d at 779. If a utility expense is "properly challenged," "[t]he Commission has the *obligation* to test the reasonableness of such expenses." *Id*. at 76, 286 S.E.2d at 779.

State ex rel. Utils. Comm'n v. Stein, 375 N.C. 870, 908, 851 S.E.2d 237, 261-62 (2020) (second and third alterations in original) (*Stein*). The Supreme Court thereafter held that "the record contain[ed] ample evidentiary support for the Commission's determination in the Duke Energy Carolinas proceeding that the intervenors had failed to elicit sufficient evidence to satisfy the burden of production imposed upon them in *Bent Creek*." *Id*. at 911, 851 S.E.2d at 263.

Finally, the Commission's orders must be based on competent, material, and substantial evidence in the record of the instant proceeding. N.C.G.S § 62-65(a). Where settlement has been reached by less than all of the parties in a case, as with the CCR Settlement in this case, that settlement should be accorded full consideration and weighed by the Commission along with all other evidence presented in reaching its decision: "The Commission may even adopt the recommendations or provisions of the nonunanimous stipulation as long as the Commission sets forth its reasoning and makes 'its own independent conclusion' supported by substantial evidence on the record that the proposal is just and reasonable to all parties in light of all the evidence presented." *CUCA I*, 348 N.C. at 466, 500 S.E.2d at 703.

The issues related to the recovery of costs incurred to comply with CAMA and the CCR Rule have been highly contentious in the last several electric utility rate cases. The parties to the proceedings have proffered pages and hours of testimony reviewing the history of coal-fired generation and the handling of coal ash throughout the history of the utilities serving North Carolina consumers, comparing the past coal ash handling practices of these utilities to others across the region and the country, debating what different decisions perhaps should have been made and when, and attempting to quantify the impact of such decisions on the CCR costs now sought to be recovered from customers. Additionally, the Commission has received significant testimony from public witnesses on these issues. Indeed, coal ash — including environmental impact and associated cost — was the predominant topic at the public witness hearings held in the instant case.

As noted above, the Public Staff has argued that responsibility for these costs (not otherwise imprudently incurred) should be shared equally between the utility and its customers. Other parties have argued that the utility should bear all or substantially all of the costs of compliance with the recently adopted state and federal requirements. After careful consideration, the Commission determined in the 2018 Rate Cases that the costs incurred, with one exception, were reasonable and prudent but imposed a management penalty in each case, which ultimately reduced the return that each Company would recover during the five-year amortization period.

Upon appeal of the Commission's 2018 Rate Case orders on this issue, the North Carolina Supreme Court remanded the cases to the Commission for further proceedings to consider the Public Staff's equitable sharing proposal. In summary, the Court concluded

> that the Commission did not err by: (1) allowing the inclusion of a large majority of the utilities' coal ash costs in the cost of service used for the purpose of establishing the utilities' North Carolina retail rates; (2) interpreting N.C.G.S. § 62-133(d) to authorize the Commission, in the exercise of its discretion, to allow a return on the unamortized balance of the deferred operating expenses . . . . On the other hand, we hold that the Commission erred by rejecting the Public Staff's equitable sharing proposal without properly considering and making findings and conclusions concerning "all other material facts" as required by N.C.G.S. § 62-133(d). As a result, we affirm the Commission's decisions, in part, and reverse and remand the Commissions' decisions for further proceedings not inconsistent with this decision, in part.

Stein, 375 N.C. at 946-47, 851 S.E.2d at 286.

The Court's opinion was issued on December 11, 2020 — after the close of the evidentiary record in the instant case. Subsequent to the issuance of the opinion, the CCR Settling Parties — each of which had offered evidence on the issue of CCR cost recovery in the rate cases and had participated in the appeals of the Commission's 2018 Rate Case orders — worked to reach a compromise on the issues. The CCR Settlement seeks to resolve not only the current DEP rate case but the current DEC rate case, the 2018 Rate Cases that have been remanded back to the Commission, and future costs to be incurred through January 2030 for DEC and February 2030 for DEP.

On February 12, 2021, upon joint motion of the CCR Settling Parties, the Commission issued an order reopening the evidentiary records, allowing testimony or comments on the CCR Settlement, and allowing requests for hearing by any party. The order made clear that a party's choice not to file a request for a hearing would be deemed by the Commission as a waiver by that party of its right to cross-examine the witnesses who provided testimony regarding the CCR Settlement. No testimony or comments were filed by any party, and no party requested a hearing. Thus, all parties waived their rights to introduce additional testimony or to cross-examine DEP's or the Public Staff's witnesses on their settlement testimony. The Commission will accept the CCR Settlement and the subsequently filed testimony in support of the CCR Settlement into the record of evidence in this case.

The Commission recognizes that the CCR Settlement is the product of give-and-take between the CCR Settling Parties — DEP, DEC, the Public Staff, the AGO, and the Sierra Club. The settlement and supporting testimony by the parties offer an immediate and longer-term resolution of the ratemaking treatment of CCR costs in lieu of the positions previously advocated by the parties. The settlement aims to resolve contentious issues in this and other DEP and DEC rate cases, including the 2018 Rate Cases, and strikes a balance between the Companies and their customers that all of the CCR Settling Parties found to be appropriate. The Company explains that the CCR Settlement provides benefit to customers through both immediate and future rate reduction — DEP and DEC together will absorb approximately $1.1 billion (on a North Carolina system basis) in CCR-related costs over the time period covered by the CCR Settlement, reducing the amounts they would otherwise seek to recover from customers. On a North Carolina retail basis, the net present value of the savings to customers from forgone CCR cost recovery (including applicable financing costs) amounts to more than $900 million. Importantly, a large portion of the rate reduction will occur over the near term, during a period in which many customers are suffering severe economic hardship from the COVID-19 pandemic. De May Settlement Testimony at 4:11-20. The Commission takes note that the Public Staff generally supports this position, asserting that the settlement obligates DEP and DEC to forego recovery of costs in excess of $900 million (combined DEP and DEC), resulting in a significant reduction in the proposed revenue increase in this case. Maness Settlement Testimony at 5:14-19.

The Commission recognizes that for purposes of this proceeding DEP agrees in the CCR Settlement to reduce the balance of deferred CCR costs to be recovered in this rate case by $261 million. DEP will cease to accrue financing costs on this amount as of December 31, 2020, resulting in additional savings to customers. Additionally, the CCR Settlement provides that DEP will recover the remaining balance of its deferred costs over a five-year amortization period, plus reduced financing costs during the amortization period calculated based on (1) DEP's cost of debt set forth in the Second Partial Stipulation, adjusted as appropriate to reflect the deductibility of interest expense, (2) an ROE 150 basis points lower than the 9.60% ROE set forth in the Second Partial Stipulation, and (3) a capital structure of 48% debt and 52% equity set forth in the Second Partial Stipulation.

For purposes of future rate case proceedings, DEP has agreed to reduce the balance of CCR costs to be recovered by $162 million and agrees that this amount shall cease to accrue financing costs as of December 31, 2020, which provides additional savings to customers. DEP has agreed to recover financing costs during the amortization period established in future proceedings at a reduced rate.

Finally, the Commission notes that the CCR Settling Parties have agreed to waive their rights to challenge future CCR costs on the basis that the Company's historical coal ash management practices were inadequate and led to unreasonable CCR costs being incurred or led to CCR costs being unreasonably higher than otherwise would have been incurred. The CCR Settling Parties reserve their rights only to propose an adjustment to future CCR costs on the grounds that the costs were otherwise unreasonable or were imprudently incurred.

Thus, the CCR Settling Parties in the CCR Settlement settle the ratemaking treatment of CCR costs in this rate case and future rate cases. The settlement aims to reduce costs that are passed on to customers, to avoid additional protracted litigation over the Companies' historical management practices, and to provide some closure to the debate that has been waged for many years. Indeed, the parties to the Companies' rate cases have extensively litigated these contested issues since at least the filing of the 2018 Rate Cases, and the CCR Settlement seeks to resolve comprehensively certain issues for CCR Costs incurred by DEP from January 1, 2015, through February 28, 2030.

While the CCR Settlement is a nonunanimous settlement, the Commission places significant weight on the fact that the Public Staff and the AGO, each of which has litigated the issues associated with CCR cost recovery vigorously in these cases and advocated zealously for consumers, are parties to the CCR Settlement. Moreover, beginning with the 2018 Rate Cases, the CCR Settling Parties have advocated for significantly different ratemaking treatment for CCR costs, particularly as to how much cost should be borne by customers versus by the Companies. Thus, the Commission recognizes the extent of the compromise and give and take that was necessary to achieve consensus on the ratemaking issues. As noted by Public Staff witness Maness, "among the most important benefits provided by the CCR Settlement are: (1) the agreement of DEC and DEP to forego recovery of CCR Costs and associated Financing Costs in excess of $900 million (combined DEC and DEP), on a present value basis, over the period from January 1, 2015, through January 31, 2030 (DEC), and February 28, 2030 (DEP), resulting in a significant reduction in the proposed revenue increase in this case; (2) the agreement to allocate any proceeds of CCR insurance litigation; and (3) the avoidance of protracted litigation over CCR and Financing Costs into 2030 among the parties to the CCR Settlement and possibly the appellate courts." Maness Settlement Testimony at 5:10-6:3. For these reasons, the Public Staff concludes that the CCR Settlement is in the public interest. Similarly, as noted by Company witness De May, the settlement "represents a balanced solution" that provides both immediate and long-term savings for customers while providing the certainty the Company requires to meet its business needs. Further, witness De May explains that the settlement allows the Company and the CCR Settling Parties to put the debate behind them and move forward to focus on a cleaner energy future. De May Settlement Testimony at 3:8-16. For these reasons, the Company concludes that the CCR Settlement is in the public interest.

CUCA is the one party to the proceeding that presented evidence regarding DEP's CCR costs but did not join the CCR Agreement.[4] CUCA witness O'Donnell testified that the North Carolina legislature passed CAMA in 2014 in response to the Dan River spill and that CAMA is more stringent than the CCR Rule. He recommended that DEP not be allowed to recover CCR costs associated with any plant that is not subject to the CCR Rule but that is subject to CAMA. He further recommended that to the extent any site is no longer receiving coal ash, remediation costs should not be paid for by ratepayers in this case or any future cases. CUCA's position was refuted by the Company in this case. In addition, CUCA's position was previously rejected by the Commission in DEC's 2018 Rate Case. It was similarly raised by CUCA, refuted by the Company, and rejected by the Commission in the DEP's 2018 Rate Case. These Commission determinations were upheld by the North Carolina Supreme Court in *Stein*. As was the case in the 2018 proceeding, CUCA witness O'Donnell did not quantify any amount that should not be recovered based on the contention that CAMA was enacted in response to the Dan River spill or that CAMA has resulted in the Company's incurring identifiable incremental costs. Rather, he testified simply that consumers should not pay for all of the Company's costs incurred and that the costs should be split equally among the Company and its customers, similar to the recommendation of the Public Staff. However, the Commission notes that the Commission's adoption of the CCR Settlement provides CUCA with its requested relief of a sharing of CCR costs.

In its Order Declining to Adopt Proposed Settlement Rules, the Commission emphasized that "settlements should be encouraged, and that the Commission should do all it lawfully and reasonably can to facilitate the parties' efforts to reach a full and fair settlement." *Rulemaking Proceeding to Consider Proposed Rule Establishing Procedures for Settlements and Stipulated Agreements*, No. M-100, Sub 145, at 10 (N.C.U.C. Mar. 1, 2017). In the instant proceeding, after years of litigation before this body and the courts, the CCR Settling Parties have worked to achieve a settlement of their views and what they perceive to be a full and fair resolution of their disparate positions. In recognition of the foregoing, and in light of the evidence in the record, the Commission is persuaded that the compromise embodied in the CCR Settlement is in the public interest. The CCR Settlement appropriately resolves the issues involving the ratemaking treatment of the costs incurred in connection with DEP's management, handling, and remediation of CCRs, including the financing costs incurred while those costs are deferred and while they are being recovered. In addition, the CCR Settlement provides benefits to customers, including a significant reduction in the amount of costs to be recovered by the Company, certainty as to the application of insurance proceeds for customers' benefit, and the avoidance of protracted and expensive litigation regarding the Companies' historical handling of CCRs. The CCR Settlement, which provides significant savings to customers in the near term, also appropriately balances the need for rate relief with the impact of such rate relief on customers in light of the current economic conditions faced by customers due to the COVID-19 pandemic.

[4] The Commission notes that CUCA is indicated as "not objecting" to the CCR Settlement and did not request an opportunity to present additional evidence on the CCR Settlement or cross-examine the witnesses of the Company or the Public Staff on the CCR Settlement.

At the four public witness hearings conducted by the Commission in this proceeding in which public witnesses appeared and testified before the Commission, a majority of those witnesses who testified expressed concerns regarding the costs and impacts of coal-fired electricity generation. At those hearings, the Commissioners heard first-hand the many perspectives and opinions of customers as to the clean-up of coal ash and the associated costs. Specifically, the following witnesses provided testimony expressing that customers should not bear responsibility for paying for the clean-up of CCRs: (1) in Raleigh 14 out of the 16 public witnesses, including Adamsky, Hutchby, Springer, Seelam, Thompson, Huang, Reibold, Duvall, Black, Moriarty, Cain, Owens, Guckert, and Weston; (2) in Wilmington 13 out of the 14 public witnesses, including Harton, Vlasits, Reber, Willis, Buckles, Sordellini, Endo, Holder, Dicks-Maxwell, Wright, and Peterson ; (3) in Snow Hill three out of the five public witnesses, including Jones, Herring, and Lanier; and (4) in Asheville 12 out of the 23 public witnesses, including Scales, Biziewski, Strawderman, Holt, Jones, Saulsbury, Mandler, Moore, Mattox, Brame, Noyes, and Resnick. Tr. vol. 2, 19-30, 32-37, 45-68; tr. vol. 3, 19-24, 36-48, 56-68; tr. vol. 4, 15-18, 32-36; tr. vol. 5, 23-25, 27-31, 40-43, 51-55, 61-70, 74-78. In addition, those who wrote to express concern emphasized many of the same perspectives. Of the numerous statements of consumer position filed in the docket a majority expressed that customers should not bear responsibility for costs associated with the clean-up of coal ash. *See generally*, Docket No. E-2, Sub 1219CS. Thus, based on the perspectives and concerns consistently expressed by witnesses at the public hearings and in the statements of consumer position filed in the docket, the Commission concludes that the history and legacy of coal-fired electricity generation by the Company is an issue of significant importance to its customers, and their perspectives must be given weight in the Commission's decision-making process. While the CCR Settlement may not go as far as many customers advocated, it strikes a fair balance for customers that the Commission determines will reduce costs (and rates) associated with CCRs, particularly in the near term, and furthers the Company's financial health and access to capital at a reasonable cost.

For these reasons, the Commission concludes that the CCR Settlement is in the public interest and should be approved. Moreover, the Commission concludes that the ratemaking treatment of CCR costs, set forth in the CCR Settlement, in conjunction with the other decisions contained within this Order, results in just and reasonable rates for DEP's customers.

Finally, the Commission asked a number of questions at the hearing in this case, including requests for late-filed exhibits analyzing the issue, regarding the possibility to recovering future CCR costs contemporaneously with the expense as an alternative to deferral and amortization, as proposed by the Company in its previous rate case. The Commission notes that the CCR Settlement does not involve such a cost recovery mechanism, opting instead to follow the "spend-defer-recover" method. In accepting and adopting the CCR Settlement, the Commission is not deciding that a cost recovery mechanism that would allow the Company to recover contemporaneously as costs are incurred is without merit. Rather, given the greater certainty that exists with respect to annual costs to be incurred, the Commission sees merit in such an approach, particularly if structured to result in savings to customers. The Commission directs the Company to consider the proper extent to which a contemporaneous cost recovery mechanism could be joined with the "spend-defer-recover" method prior to the next general rate case.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 24-26

ARO Accounting

The evidence supporting these findings of fact is found in the verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

There has been substantial discussion devoted to the subject of "ARO accounting" in the current proceeding as well as prior DEP proceedings. The Commission will not discuss in detail here the testimony presented by the various parties but will summarize the pertinent facts.

In June 2001 the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards 143, Accounting for Asset Retirement Obligations (SFAS 143), which addressed financial accounting and reporting requirements associated with an entity's legal requirement to retire a long-lived asset. Specifically, SFAS 143 required an entity to recognize the fair value of a liability for an asset retirement obligation (ARO), in the period in which it is incurred if a reasonable estimate of the fair value can be determined. Additionally, upon initial recognition of a liability for an ARO, an entity was required to capitalize an asset retirement cost (ARC) by increasing the carrying amount of the related long-lived asset by the same amount as the liability. SFAS 143 was later codified as Accounting Standards Codification 410, Asset Retirement and Environmental Obligations (ASC 410).

In response to the issuance of SFAS 143, on October 30, 2002, the FERC issued a Notice of Proposed Rulemaking to revise the USOA so that FERC accounting requirements would be consistent with those used by FERC regulated entities for financial reporting purposes. On April 9, 2003, the FERC issued an order amending the USOA. *Accounting, Financial Reporting, and Rate Filing Requirements for Asset Retirement Obligations*, Order No. 631, 103 FERC ¶ 61,021, *reh'g denied*, Order No. 631-A, 104 FERC ¶ 61,183 (2003). Specifically, FERC added new balance sheet and income statement accounts. The FERC ruled that no FERC-regulated entity with formula rate tariffs could include ARO costs in their billing determinations without prior approval. As a FERC-regulated entity DEP must comply with the USOA. In addition, Commission Rule R8-27 states that the Commission adopted the FERC USOA as the accounting rules applicable to electric utilities under its jurisdiction subject to certain exceptions and conditions. One such exception is that electric utilities under the jurisdiction of this Commission are required to seek approval to record any items in FERC account 182.3 - Other Regulatory Assets.

On December 23, 2002, in response to FASB's issuance of SFAS 143, DEP filed a petition in Docket No. E-2, Sub 826 for authority to place certain ARO costs in a deferred account. A request for deferral accounting was necessary so that adoption of SFAS 143 "would have no impact on [DEP's] operating results or return on rate base for North Carolina retail regulatory purposes" such that DEP's "North Carolina retail rate base, net operating income, and regulatory return on common equity" would be the same as they would have been absent the implementation of SFAS 143. Order Granting Motion for Reconsideration and Allowing Deferral of Costs, *Petition for Authority to Place Certain Asset Retirement Obligation Costs in a Deferred Account*, No. E-2, Sub 826, at 11-12 (N.C.U.C. Aug. 12, 2003) (Sub 826 Order).

In its Sub 826 Order the Commission required DEP to make a filing setting forth the journal entries it recorded when initially implementing SFAS 143. Further, DEP was required to file annual reports reconciling the account balances in the Company's annual report filed pursuant to Commission Rule R1-32 and the annual North Carolina retail cost of service studies filed with the Commission.

On January 20, 2004, DEP filed the required journal entries. As shown therein, at the time of implementation of SFAS 143 the only ARO recorded by DEP was for decommissioning of its nuclear plants. A review of subsequent reconciliation reports shows that it was not until DEP filed its reconciliation report for 2014, after the enactment of CAMA, that there was an ARO associated with coal ash removal. After the enactment of the CCR Rule, the report for 2015 showed a significant increase in the ARO coal ash removal.

DEP's Chief Financial Officer, Brian Savoy, wrote a letter to the Commission dated December 21, 2015 (Savoy letter), explaining that due to both CAMA and the CCR Rule, the ARO recorded on DEP's books as of November 30, 2015, was approximately $2.13 billion but noted that actual costs to comply with CAMA and the CCR Rule could be materially different. The Company stated that it was not seeking further specific accounting approval at that time but was simply providing an explanation of its accounting for ash basin closure and compliance costs for the Commission's information. DEP stated that only actual costs resulting in cash outlays by the Company related to ash basin closure, plus carrying charges, would result in amounts for which the Company would seek accounting and rate treatment in future filings. In the current proceeding, DEP witness Riley explained this concept when he testified that ARO assets and liabilities are presented on a company's balance sheet as a result of accounting journal entries, not from investor or customer contributions, and therefore are not considered for ratemaking purposes until actual costs are expended. Tr. vol. 23, 131.

DEP made such a petition for an accounting order on December 30, 2016, in Docket No. E-2, Sub 1103. In that filing DEP requested approval to defer, in a regulatory asset, costs incurred after January 1, 2015, to comply with federal and state regulations and a return on those costs at the Company's approved weighted cost of capital, until the approval of new rates in the Company's next base rate case. DEP stated that from January 2015 through November 2016, the Company had incurred $291.9 million of expenses for state and federal compliance. On July 10, 2017, the Commission issued an Order consolidating DEP's request with its then pending general rate case proceeding, Sub 1142.

Prior to seeking rate recovery, the Company's requests and the Commission's decisions were simply intended to ensure that DEP complied with GAAP and FERC accounting requirements but also that such compliance did not impact North Carolina retail ratemaking. When DEP requested recovery in rates of deferred ash basin closure costs the issue before the Commission was no longer one of accounting but rather of ratemaking.

The approval by the Commission of a five-year amortization period for deferred costs in Sub 1142 did not change the Company's requirement to comply with GAAP and FERC. The Company must still record AROs and ARCs; however, for financial reporting purposes those amounts will be adjusted for amounts approved for recovery in rates. This is shown on DEP Late Filed Exhibit No. 24 where the amount recorded in Account 182.3 Regulatory Assets "theory" will be transferred to Account 182.3 Regulatory Assets "spend". The same accounting was set forth in Public Staff Late Filed Exhibit No. 4.

The Commission reiterates that it will not discuss in detail the various testimony surrounding ARO accounting, ARO-related accounting, deferred expenses, or capitalized costs. The nomenclature applied to the costs which DEP has incurred and will continue to incur in order to comply with both CAMA and the CCR Rule is not pertinent to the ratemaking treatment of such costs. The Commission determined in Finding of Fact No. 50 in the Sub 1142 Order that the Company's request to defer in a regulatory asset account certain costs incurred in connection with compliance with federal and state environmental requirements was reasonable and appropriate. The Commission also determined in Finding of Fact No. 51 that DEP expects to incur substantial costs related to coal ash remediation in future years, and that it was just and reasonable to allow deferral of those costs, with a return at the net-of-tax overall cost of capital approved in the 2018 DEP Rate Order, and that the ratemaking treatment of those costs would be addressed in future rate proceedings. The instant proceeding is such a proceeding. The only determination required of the Commission in this proceeding is the prudence of the Company's expenditures and the appropriate amortization period for recovery of such prudently incurred costs. These questions are addressed elsewhere in this Order.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 27-32

Capital Structure, Cost of Capital, and Overall Rate of Return

The evidence supporting these findings of fact is found in the verified Application and Form E-1; the stipulations entered into between DEP and several parties; the testimony and exhibits of DEP witnesses D'Ascendis, Newlin, Young, and Fetter, Public Staff witnesses Woolridge and Hinton, AGO witness Baudino, Commercial Group witness

Chriss, CIGFUR witness Phillips, and CUCA witness O'Donnell; and the entire record in this proceeding.

A. Rate of Return on Equity Capital

Summary of the Evidence

In his direct testimony witness D'Ascendis recommended an ROE of 10.50%; however, in its Application, as a rate mitigation measure, the Company requested approval for its rates to be set using an ROE of 10.30% and an overall rate of return of 7.41%. The Company later stipulated to an ROE of 9.75% in individual settlement agreements with Harris Teeter, the Commercial Group, CIGFUR, Vote Solar, NCSEA and NCJC et al., which is a decrease from the 9.90% ROE and overall rate of return of 7.09% authorized by the Commission in the Company's last rate case, Sub 1142. Subsequently, the Company and the Public Staff executed the Second Partial Stipulation that provides for an ROE of 9.60%. As a result, the HT Stipulation, CG Stipulation, CIGFUR Stipulation, Vote Solar Stipulation, and NCSEA/NCJC et al. Stipulation were each amended as previously described to provide that if the Commission enters a final order in this docket approving a rate of return of 9.60% to be applied to a common equity component of the ratemaking capital structure consisting of 52% equity and 48% long-term debt, those parties would agree that the provisions of their settlement agreements concerning the ROE and capital structure have been fulfilled.

Witnesses for the Public Staff, CIGFUR, the AGO, the Commercial Group, and CUCA also filed direct testimony on the appropriate ROE to be established in this rate case. This evidence was followed by the Public Staff First and Second Partial Stipulations and the other intervenor settlements, supplemental testimony of witness Baudino, rebuttal, supplemental rebuttal, and settlement testimony of witness D'Ascendis, settlement testimony of witness Woolridge, and finally testimony of witnesses D'Ascendis, Baudino, and O'Donnell at the consolidated hearing in this matter. In addition to this expert testimony the Commission received the testimony of a number of public witnesses on DEP's proposed rate increase as well as numerous statements of consumer position. All of this evidence is summarized below.

DEP Direct Testimony

Company witness D'Ascendis recommended in his direct testimony an ROE of 10.50%, which was the midpoint of his recommended range of 10.00% to 11.00%. Tr. vol. 11, 250. Witness D'Ascendis stated that the ROE, or the cost of equity, is the return that investors require to make an equity investment in a firm. That is, investors will provide funds to a firm only if the return that they *expect* is equal to, or greater than, the return that they *require* to accept the risk of providing funds to the firm. From the firm's perspective, that required return represents the cost of equity capital. Witness D'Ascendis testified that the cost of equity is neither directly observable nor a contractual obligation. Rather, equity investors have a claim on cash flows only after debt holders are paid; the uncertainty (or risk) associated with those residual cash flows determines the cost of equity. Since the cost of equity cannot be directly observed, it must be estimated or inferred based on market data and various financial models. Witness D'Ascendis testified that each of those models is subject to specific assumptions, which may be more or less applicable under differing market conditions. *Id*. at 260-61.

Witness D'Ascendis noted that, as all financial models are subject to various assumptions and constraints, equity analysts and investors tend to use multiple methods to develop their return requirements. *Id*. at 251. He therefore relied on three widely accepted approaches to develop his ROE determination: (1) the Constant Growth and Multi-Stage forms of the Discounted Cash Flow (DCF) model; (2) the Capital Asset Pricing Model (CAPM); and (3) the Bond Yield Plus Risk Premium approach. *Id*. He noted, however, weaknesses in the Constant Growth DCF Model, namely that those results are far removed from the returns recently authorized in other jurisdictions and fail to adequately reflect evolving capital market conditions and therefore discounted those results. *Id*. at 252. The Constant Growth DCF Model produced ROE results ranging from a low of 8.78% to a high of 9.85% and the Risk Premium-based approaches, including the CAPM, Empirical CAPM, and Bond Yield Plus Risk Premium methods, produced results ranging from a low of 8.44% to a high of 10.93% in connection with one variant of the Empirical CAPM. *Id*. at 258. Finally, the Expected Earnings analysis, which is used to assess the reasonableness of the DCF, CAPM, and Bond-Yield Plus Risk Premium results, produces an ROE estimate with a mean of 10.47% and a median of 10.54%. *Id*. at 259. Witness D'Ascendis noted that FERC uses the Expected Earnings analysis to determine the "zone of reasonableness." *Id*. at 272.

Witness D'Ascendis provided extensive testimony concerning the capital market environment and addressed the effect those market conditions have on the return investors require in order to commit their capital to equity securities. Witness D'Ascendis also focused upon capital market conditions as they affect the Company's customers in North Carolina. *Id*. at 299-309. Specifically, his analysis found that the North Carolina and national economies continue to be highly correlated with one another. *Id*. at 300-01. He concluded therefore that North Carolina conditions "continue to be reflected in the models and data used to estimate the Cost of Equity." *Id*. at 301.

In addition to his econometric models and evaluation of capital market risks, witness D'Ascendis also considered Company-specific business risks in arriving at his final ROE recommendation. These included (1) the risks associated with certain aspects of the Company's generation portfolio, and (2) the Company's significant capital expenditure plan. *Id*. at 283-84.

Regarding economic conditions in North Carolina, witness D'Ascendis noted that North Carolina and the counties comprising DEP's service area "continue to steadily emerge from the economic downturn that prevailed during 2009-2010 and have experienced significant economic improvement during the last several years." *Id*. at 308.

Public Staff Testimony

Witness Woolridge performed DCF and CAPM analyses for both his and witness D'Ascendis' proxy groups of electric utilities. Tr. vol. 15, 528-29. Witness Woolridge developed his DCF growth rate after reviewing growth rate measures including historic and projected growth rate measures and evaluating growth in dividends, book value, earnings per share (EPS), and growth rate forecasts from Yahoo, Reuters, and Zack's. *Id*. at 589-90. Witness Woolridge applied the DCF model and CAPM that yielded the following results:

Discounted Cash Flow (DCF) – Electric Proxy Group
- 8.15% Equity Cost Rate

DCF – D'Ascendis Proxy Group
- 8.40% Equity Cost rate

CAPM – Electric Proxy Group and D'Ascendis Proxy Group
- 6.70% Equity Cost Rate

Id. at 616.

In witness Woolridge's CAPM analysis he used for the risk-free interest rate the top end of the range of yields on 30-year U.S. Treasury bonds over the 2013-2020 time period, 3.50%. *Id*. at 602. He used the Value Line Investment Survey betas of 0.55 for both his and witness D'Ascendis' proxy groups. *Id*. at 604. Witness Woolridge's market risk premium was 5.75%, which gave the most weight to the market premium estimates of KPMG, CFO Survey, Duff & Phelps, the Fernandez survey, and Damodaran. *Id*. at 614-15. He testified that his 5.75% value is a conservatively high estimate of the market risk premium. *Id*. at 615.

Witness Woolridge concluded that the appropriate equity cost rate for companies in his and witness D'Ascendis' proxy groups is in the 6.70% to 8.40% range. *Id*. at 616. However, witness Woolridge took into account the fact that his range was below the authorized ROEs for electric utilities nationally and made a primary recommendation of a 9.00% ROE, assuming a 50% common equity ratio. *Id*. at 617. Witness Woolridge also provided an alternative recommendation of an 8.40% ROE based on the Company's originally requested capital structure of 53% equity and 47% debt. *Id*.

Witness Woolridge did not perform an ECAPM analysis. He testified that the ECAPM is an ad hoc version of the CAPM. *Id*. at 653.

Witness Woolridge also testified as to current capital market conditions as of the date of his testimony in April 2020. He stated that although the Federal Reserve increased the Federal Funds rate between 2015 and 2018, interest rates and capital costs remain at low levels. *Id*. at 538, 542. Witness Woolridge also pointed out that in 2019 interest rates fell dramatically with moderate economic growth and low inflation, while the Federal

Reserve cut the federal fund rate in July, September, and October and the 30-year yield traded at all-time low levels. *Id*. at 540. He noted that from January 1, 2020, through March 18, 2020, the yield on the benchmark 30-year Treasury bond had declined from 2.0% to 1.6%, even trading as low as 0.9%, an all-time low. *Id*. at 672-73. He found that the volatility in the markets since mid-February suggested a state of disequilibrium such that analyses using current market data would not provide reliable estimates of the cost of equity capital. Instead, he relied on data from the first week of February 2020. *Id*. at 685.

Witness Woolridge responded to witness D'Ascendis' assessment of the economic conditions in North Carolina prior to the COVID-19 pandemic. He generally agreed with witness D'Ascendis' general conclusion that economic conditions in North Carolina had improved since the Company's last rate case. Witness Woolridge stated that "[a]s highlighted by the correlations between U.S. and North Carolina economic data . . . economic conditions have improved with the overall economy over the past decade." Tr. vol. 15, 667. He argued, however, that although economic conditions generally had improved in North Carolina, other conditions such as a higher unemployment rate in the DEP service territory than the national average, a median household income in North Carolina that is lower than the national figure and the greater than 100 basis point difference in DEP's requested ROE and the average authorized ROEs for electric utilities in 2018-2019, do not support the Company's proposed ROE. *Id*. at 667-68.

AGO Testimony

Witness Baudino proposed an ROE of 9.00% based on a capital structure comprising 51.50% equity and 48.50% long-term debt. Witness Baudino's recommendation was based upon his DCF-based market approaches along with the CAPM approach. Tr. vol. 13, 444-45. Witness Baudino later provided prefiled Supplemental Direct Testimony where he updated interest rates and market data "since the beginning of March 2020 when concerns about the COVID-19 pandemic began to roil financial markets with extreme volatility." *Id*. at 511. Witness Baudino testified regarding the recent volatility in the markets, including "sharp increase in betas for the companies in the proxy group." *Id*. at 520. His analysis resulted in an updated DCF ranging from 8.29 to 9.28, an increase from his initial DCF range of 8.21 to 9.02. *Id*. at 518; tr. vol. 2, 128. Likewise, witness Baudino testified that nationally the real GDP "declined in the first quarter of 2020 by -5.0%, according to the Bureau of Economic Analysis." Tr. vol. 13, 523. Nevertheless, he continued to recommend a 9.00% ROE in his supplemental direct testimony. *Id*.

Witness Baudino further testified that his 9.00% ROE recommendation was "reasonably close to recently allowed ROEs." Tr. vol. 13, 480. As a reference point to determine "reasonably close" he relied upon average public utility commission allowed ROEs during 2016, 2017, 2018, and 2019, *see* Tr. vol. 2, 135-37, which he calculated as 9.60%, 9.68%, 9.56%, and 9.57%, respectively. Tr. vol. 13, 478-79.

CUCA Testimony

Witness O’Donnell proposed an ROE of 8.75%, primarily based upon DCF modeling and CAPM methodologies, as well utilizing a comparable earnings approach. Tr. vol. 14, 229. Witness O’Donnell's DCF analysis results ranged from 7.0% to 10.0% with a midpoint of 8.50%, his CAPM analysis ranged from 5.0% to 7.0% with a midpoint of 6.50%, and his comparable earnings analysis ranged from 9.25% to 10.25% with a midpoint of 9.75%. *Id*. He believed that the midpoint of his DCF was the most accurate representation of market conditions as supported by his CAPM analysis but chose a return in the upper end of his DCF range based on allowed returns from other jurisdictions. *Id*.

Commercial Group Testimony

Although he did not provide an ROE analysis in his testimony, witness Chriss testified that the Company’s proposed ROE was significantly higher than rates previously approved by the Commission from 2016 to present. Tr. vol. 14, 86-87. Likewise, witness Chriss indicated that the Company’s proposed ROE is significantly higher than most reported ROE decisions by utilities commissions from 2016 to the present. *Id*. at 87-88. He testified that according to S&P Global Market Intelligence, 154 decisions were rendered over that time frame, with results ranging from 8.40% to 11.95%, and the median authorized ROE was 9.60%. *Id*. at 87. Removing distribution-only utilities and distribution service rates from the analysis, he testified that the average ROE for vertically integrated utilities authorized from 2016 through the time of his direct testimony filing was 9.74%, and the trend in these averages has been relatively stable. *Id*. at 87-88. As previously noted, the Commercial Group subsequently entered into a settlement agreement where the parties agreed to a 9.75% ROE that was subsequently amended to provide that if the Commission authorized a 9.60% ROE, the parties agree that the provisions of their agreement on ROE and capital structure shall have been fulfilled.

CIGFUR Testimony

CIGFUR witness testified that DEP’s requested ROE of 10.30% is unreasonable and should be rejected. Tr. vol. 16, 316-17. He presented evidence that the national average authorized ROE for vertically integrated electric utilities is currently 9.73%. *Id*. at 317. He recommended that a reasonable ROE for DEP should not exceed the current national average for vertically integrated electric utilities. *Id*. Similar to the Commercial Group, CIGFUR subsequently entered into a settlement agreement where the parties agreed to a 9.75% ROE that was subsequently amended to provide that if the Commission authorized a 9.60% ROE, CIGFUR would agree that the provisions of its agreement on ROE and capital structure shall have been fulfilled.

DEP Rebuttal Testimony

Witness D’Ascendis responded to and discussed in detail the intervenor witnesses’ criticisms of his ROE conclusions and recommendations. He indicated that “none of their arguments caused me to revise my conclusions or recommendations." Tr. vol. 1, 46. Witness D'Ascendis stated that "financial models are important tools in determining returns and understand[s] that because all [models] are subject to assumptions, no one method is most reliable at all times, or under all conditions" and therefore it "remains critically important to apply reasoned judgment to determine where the Cost of Equity falls within that model's range of results." Tr. vol. 11, 355.

Generally, witness D'Ascendis advised that over the last five years nearly all authorized ROEs for vertically integrated electric utilities have been above the intervenor witnesses' recommendations. *Id*. at 353. Witness D'Ascendis also included as Chart 1 of his Rebuttal Testimony a comparison of authorized ROEs for other vertically integrated utilities from 2015 through January 2020 that he testified shows that the intervenor witness recommendations[5] are far below the ROEs available to other such utilities. *Id.* at 354.

Witness D'Ascendis indicated that the "significant departure" represented by the recommendations of witnesses Baudino and O'Donnell raises two concerns. First, DEP must compete with other companies, including utilities, for the long-term capital needed to provide safe and reliable utility service, and such competition means that the Company would be at a disadvantage in the capital markets if the Commission were to approve an ROE in the ranges recommended by witnesses Baudino and O'Donnell. As a result, he testified a likely outcome would be increasing reluctance on the part of investors to provide capital at reasonable costs and terms. Witness D'Ascendis also noted that while they are not exclusively relied upon, authorized ROEs provide observable and measurable benchmarks against which return recommendations may be assessed. *Id*. at 354-55.

Witness D'Ascendis criticized the growth rates witness Baudino applied to the Constant Growth DCF model and his reliance on the Constant Growth DCF model to determine the Company's ROE, the Market Risk Premium witness Baudino used in the CAPM, witness Baudino's statements concerning the relevance of the ECAPM analysis, as well as the reasonableness of his Bond Yield Plus Risk Premium analysis, among other factors. *Id*. at 487. He responded to each and concluded that none of witness Baudino's arguments resulted in the revision of witness D'Ascendis' conclusions or recommendations.

Witness D'Ascendis also challenged witness O'Donnell's application of the Constant Growth DCF and subsequent recommendation for an ROE of 8.75%. *Id*. at 529. Witness D'Ascendis explained that the reliance on historical growth rates by witnesses O'Donnell and Baudino as part of their Constant Growth DCF modeling does not adequately encapsulate how the model is a forward-looking measure of investors' expectations and there is support that future growth is superior to that of historically oriented growth measures. In response to Witness O'Donnell's contention that the DCF

[5] The chart prepared by witness D'Ascendis reflects witness Woolridge's original 9.00% ROE recommendation.

approach is far superior to all the models now used by practitioners, witness D'Ascendis contended that no support was offered for that assertion. In response to witness O'Donnell's use of the Retention Growth Model, witness D'Ascendis tested the relationship between retention ratios and future growth rates and demonstrated that earnings growth actually *decreased* as the retention ratio increased. Tr. vol. 11, 540. Witness D'Ascendis testified that the CAPM addresses comparable risk in a way that the DCF-based methods do not; the Beta coefficient reflects "systematic" risk, which provides a direct measure of relative risk. *Id*. at 549.

Additionally, witness D'Ascendis testified that the intervenor witnesses fail to recognize the risks faced by the Company and their recommended ROEs do not appropriately reflect the capital market environment. *Id*. at 351. To illustrate his point that an ROE in the range recommended by Baudino and O'Donnell would risk devaluing the Company's equity and, thus, its ability to compete for capital, witness D'Ascendis provided an example of a recent rate decision for CenterPoint Energy Houston Electric in which the financial community responded negatively to an adverse regulatory outcome. *Id*. at 527.

Witness D'Ascendis also prefiled supplemental rebuttal testimony to update his ROE models and respond to the prefiled supplemental direct testimony of AGO witness Baudino regarding current and expected capital markets and their effect on the cost of equity.

Witness D'Ascendis noted that even though the North Carolina and U.S. economies have contracted, economic conditions in North Carolina continue to be highly correlated to conditions nationally, and, therefore, continue to be reflected in the analyses used to determine the ROE. Tr. vol. 11, 614. In addition, evidence was presented that shows that the current level of volatility, which is 50% higher than normal levels, is expected to persist until at least the end of 2021. *Id*. at 612.

Witness D'Ascendis updated his ROE analyses based on market data as of June 30, 2020, resulting in a DCF ranging from 7.76% to 9.67%, a CAPM ranging from 10.19% to 15.70%, an ECAPM ranging from 10.94% to 15.70%, a Bond Yield Risk Premium ranging from 9.96% to 10.25%, and an Expected Earnings ranging from 5.50% to 13.56%. *Id*. at 594-95; D'Ascendis Supplemental Rebuttal Exs.1-6.

Stipulations

As discussed above, in separate stipulations with CIGFUR, the Commercial Group, and Harris Teeter, the Company stipulated to an ROE of 9.75%. Subsequently, the Company and the Public Staff executed the Second Partial Stipulation which among other things provided for an ROE of 9.60%. Thereafter, the other intervenor settlements were amended to provide that if the Commission enters a final order in this docket approving a rate of return of 9.60% to be applied to a common equity component of the ratemaking capital structure consisting of 52% equity and 48% long-term debt, those parties would agree that the provisions of their settlement agreements concerning the ROE and capital structure have been fulfilled.

DEP Settlement Testimony

Witness D'Ascendis provided testimony supporting the Second Partial Stipulation reached between the Public Staff and the Company, explaining that though the stipulated ROE of 9.60% is somewhat below his recommended range, he recognized that the settlement represents negotiation between the parties of otherwise contested issues and that the Company believes that the Second Partial Stipulation's ROE and capital structure "would be viewed by the rating agencies as constructive and equitable." Tr. vol. 11, 619-20. Witness D'Ascendis also testified that economic conditions in North Carolina, which deteriorated in the first half of 2020 as a result of the COVID-19 pandemic, remain highly correlated to the overall conditions nationwide. *Id*. at 626. Witness D'Ascendis noted that "[f]rom January 2016 through June 2020, the average authorized ROE for vertically integrated electric utilities was 9.74 percent, 14 basis points above the Stipulated ROE. Of the 107 cases decided during that period, 64 (i.e., nearly 60.00 percent) included authorized returns of 9.60% or higher." Tr. vol. 11, 621. He concluded that the 9.60% stipulated ROE is "a reasonable resolution of an otherwise contentious issue." *Id*. at 620.

Public Staff Settlement Testimony

Witness Woolridge testified that he found the cost of capital components reasonable within the context of the overall settlements and in resolution of most of the issues in the proceeding. Tr. vol. 15, 691-92. He noted that the stipulated ROE was a compromise for each party, a reduction from the Company's last authorized ROE of 9.90%, below the 9.67% average authorized ROE for vertically integrated electric utilities during the first half of 2020, and the lowest ROE authorized for a vertically integrated investor-owned electric utility in North Carolina in at least the last 30 years. *Id*. at 695.

Hearing Testimony

Under cross-examination by the AGO witness D'Ascendis noted that measures of volatility had fallen since March but remained high and were expected to continue to remain high. Consolidated Tr. vol. 2, 43-44. Witness D'Ascendis further testified that the North Carolina economy's response to the pandemic was highly correlated with that of the country but that the effect had been somewhat less severe and the recovery had been somewhat more rapid. He concluded that North Carolina was somewhat less effected by the recession than the nation as a whole. Consolidated Tr. vol. 1, 125-26.

Public Witness Testimony and Consumer Statements of Position

The Commission also received numerous statements of consumer position regarding this docket, many of which expressed concern about DEP's proposed rate increase. The Commission held five evening hearings throughout the Company's North

Carolina service territory to receive public testimony. A total of 58 individuals testified and several testified that the rate increase was not affordable for many customers, including those on fixed incomes, the elderly, person with disabilities, the unemployed and underemployed, and the impoverished.

Law Governing the Commission's Decision on ROE

The ROE is often one of the most contentious issues to be addressed in a rate case, even in a case such as this one in which the Second Partial Stipulation and the other intervenor settlements have been reached. In the absence of a settlement agreed to by all the parties, the law of North Carolina requires the Commission to exercise its independent judgment and arrive at its own independent conclusion as to the proper ROW. *See, e.g., CUCA I,* 348 N.C. at 466, 500 S.E.2d at 707. In order to reach an appropriate independent conclusion regarding the ROE, the Commission must evaluate the available evidence, particularly that presented by conflicting expert witnesses. *State ex rel. Utils. Comm'n v. Cooper*, 366 N.C. 484, 491-93, 739 S.E.2d 541, 546-47 (2013) (*Cooper I*).

The baseline for establishment of an appropriate ROE are the constitutional constraints established by the decisions of the United States Supreme Court in *Bluefield Water Works & Improvement Co. v. Public Service Commission,* 262 U.S. 679 (1923) (*Bluefield*), and *Federal Power Commission v. Hope Natural Gas Co.,* 320 U.S. 591 (1944) (*Hope*), which establish:

> To fix rates that do not allow a utility to recover its costs, including the cost of equity capital, would be an unconstitutional taking. In assessing the impact of changing economic conditions on customers in setting [an ROE], the Commission must still provide the public utility with the opportunity, by sound management, to (1) produce a fair profit for its shareholders, in view of current economic conditions, (2) maintain its facilities and service, and (3) compete in the marketplace for capital.

2018 DEC Rate Order at 50; s*ee also, State ex rel. Utils. Comm'n v. Gen. Tel. Co.*, 281 N.C. 318, 370, 189 S.E.2d 705, 738 (1972) (*General Telephone*). As the North Carolina Supreme Court held in *General Telephone*, these factors constitute "the test of a fair rate of return declared" in *Bluefield* and *Hope*. *Id.*

The ROE is, in fact, a cost. The return that equity investors require represents the cost to the utility of equity capital:

> [T]he cost of capital to the utility is synonymous with the investor's return, and the cost of capital is the earnings which must be generated by the

> investment of that capital in order to pay its price, that is, in order to meet the investor's required rate of return.

Morin, Roger A., *Utilities' Cost of Capital* 19-21 (Public Utilities Reports, Inc. 1984). "The term 'cost of capital' may [also] be defined as the annual percentage that a utility must receive to maintain its credit, to pay a return to the owners of the enterprise, and to ensure the attraction of capital in amounts adequate to meet future needs." Phillips, Charles F., Jr., *The Regulation of Public Utilities* (Public Utilities Reports, Inc. 1993), at 388.

Long-standing decisions of the North Carolina Supreme Court have recognized that the Commission's subjective judgment is a necessary part of determining the authorized ROE. *State ex rel. Utils Comm'n v. Public Staff-N.C. Utils. Comm'n,* 323 N.C. 481, 490, 374 S.E.2d 361, 369 (1988) (*Public Staff*). Likewise, the Commission has observed as much in exercising its duty to determine the ROE, noting that such determination is not made by application of any one simple mathematical formula:

> Throughout all of its decisions, the [United States] Supreme Court has formulated no specific rules for determining a fair rate of return, but it has enumerated a number of guidelines. The Court has made it clear that confiscation of property must be avoided, that no one rate can be considered fair at all times and that regulation does not guarantee a fair return. The Court also has consistently stated that a necessary prerequisite for profitable operations is efficient and economical management. Beyond this is a list of several factors the commissions are supposed to consider in making their decisions, but no weights have been assigned.
>
> The relevant economic criteria enunciated by the Court are three: financial integrity, capital attraction and comparable earnings. Stated another way, the rate of return allowed a public utility should be high enough: (1) to maintain the financial integrity of the enterprise, (2) to enable the utility to attract the new capital it needs to serve the public, and (3) to provide a return on common equity that is commensurate with returns on investments in other enterprises of corresponding risk. These three economic criteria are interrelated and have been used widely for many years by regulatory commissions throughout the country in determining the rate of return allowed public utilities.
>
> In reality, the concept of a fair rate of return represents a "zone of reasonableness." As explained by the Pennsylvania commission:

> There is a range of reasonableness within which earnings may properly fluctuate and still be deemed just and reasonable and not excessive or extortionate. It is bounded at one level by investor interest against confiscation and the need for averting any threat to the security for the capital embarked upon the enterprise. At the other level it is bounded by consumer interest against excessive and unreasonable charges for service.
>
> As long as the allowed return falls within this zone, therefore, it is just and reasonable . . . . It is the task of the commissions to translate these generalizations into quantitative terms.

Charles F. Phillips, Jr., *The Regulation of Public Utilities,* 3d ed. 1993, 381-82. (Notes omitted.)

Order Granting General Rate Increase, *Application of Carolina Power & Light Co., d/b/a Progress Energy Carolinas, Inc., for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, No. E-2, Sub 1023, at 35-36 (N.C.U.C. May 30, 2013), *aff'd*, *State ex rel. Utils. Comm'n v. Cooper*, 367 N.C. 444, 761 S.E.2d 640 (2014) (2013 DEP Rate Order).

Moreover, in setting rates the Commission must not only adhere to the dictates of both the United States and North Carolina Constitutions, but as has been held by the North Carolina Supreme Court, it must set rates as low as possible consistent with constitutional law. *Public Staff,* 323 N.C. at 490, 374 S.E.2d at 370. Further, the North Carolina General Assembly has provided that the Commission must also set rates employing a multi-element formula set forth in N.C.G.S. § 62-133. The formula requires consideration of elements beyond just the ROE element, and it inherently necessitates that the Commission make many subjective determinations, in addition to the subjectivity required to determine the ROE. The subjective decisions the Commission must make as to each of the elements of the formula can and often do have multiple and varied impacts on all of the other elements of the formula. In other words, the formula elements are intertwined and often interdependent in their impact to the setting of just and reasonable rates.

The fixing of a rate of return on the cost of property used and useful to the provision of service (as determined through the end of the historic 12-month test period prior to the proposed effective date of a requested change in rates and adjusted for proven changes occurring up to the close of the expert witness hearing) is but one of several interdependent elements of the statutory formula to be used in setting just and reasonable rates. *See* N.C.G.S. § 62-133. North Carolina General Statute § 62-133(b)(4) provides, in pertinent part, that the Commission shall:

> [f]ix such rate of return on the cost of the property . . . as will enable the public utility by sound management [1] to produce a fair return for its shareholders, *considering changing economic conditions and other factors* . . . [2] to maintain its facilities and services in accordance with the reasonable requirements of its customers in the territory covered by its franchise, and [3] to compete in the market for capital funds on terms that are reasonable and that are fair to its customers and to its existing investors. [Emphasis added.]

The North Carolina Supreme Court has interpreted the above-emphasized language as requiring the Commission to make findings regarding the impact of changing economic conditions on customers when determining the proper ROE for a public utility. *Cooper I*, 366 N.C. at 495, 739 S.E.2d at 548. The Commission must exercise its subjective judgment so as to balance two competing ROE-related factors — the economic conditions facing the Company's customers and the Company's need to attract equity financing on reasonable terms in order to continue providing safe and reliable service. 2013 DEP Rate Order at 35-36. The Commission's determination in setting rates pursuant to N.C.G.S. § 62-133, which includes the fixing of the ROE, always takes into account affordability of public utility service to the using and consuming public. The impact of changing economic conditions on customers is embedded in the analyses conducted by the expert witnesses on ROE, as the various economic models widely used and accepted in utility regulatory rate-setting proceedings take into account such economic conditions. 2013 DEP Rate Order at 38. Further,

> [t]he Commission always places primary emphasis on consumers' ability to pay where economic conditions are difficult. By the same token, it places the same emphasis on consumers' ability to pay when economic conditions are favorable as when the unemployment rate is low. Always there are customers facing difficulty in paying utility bills. The Commission does not grant higher rates of return on common equity when the general body of ratepayers is in a better position to pay than at other times . . . .

Id. at 37. Economic conditions existing during the modified test year, at the time of the public hearings, and at the date of the issuance of the Commission's order setting rates will affect not only the ability of the utility's customers to pay rates but also the ability of the utility to earn the authorized rate of return during the period the new rates will be in effect. However, in setting the ROE, just as the Commission must assess the impact of economic conditions on customers' ability to pay for service, it likewise must assess the effect of regulatory lag[6] on the Company's ability to access capital on reasonable terms.

[6] Regulatory lag can cause a utility's realized, earned return to be less than its authorized return, negatively affecting the shareholder's return on investment as other expenses and debts owed are paid ahead of investor return.

The Commission sets the ROE considering both of these impacts taken together in its ultimate decision fixing a utility's rates.

Thus, in summary and in accordance with the applicable law, the Commission's duty under N.C.G.S. § 62-133 is to set rates as low as reasonably possible to the benefit of the customers without impairing the Company's ability to attract the capital needed to provide safe and reliable electric service and recover its cost of providing service.

Discussion and Application of Law to the Facts

The Commission has examined the Company's Application and supporting testimony and exhibits and Form E-1 filings seeking to justify its requested increase. DEP's updated request prior to entering into the Stipulations and including the May 2020 Updates was a retail revenue increase of approximately $569.7 million in annual revenues. DEP and the Public Staff, who in this docket represents all users and consumers of the Company's electric service, entered into a stipulation on ROE and capital structure that resulted in reducing the retail revenue increase sought by the Company by $59.3 million. Smith Second Settlement Ex. 3. CIGFUR, the Commercial Group, and Harris Teeter each entered into a separate stipulation that, as amended, accepted a 9.60% ROE, subject to certain conditions. As with all settlement agreements, each party to the stipulations gained some benefits that it deemed important and gave some concessions for those benefits. Based on DEP's Application, it is apparent that the stipulations tie the 9.60% ROE to substantially agreed upon concessions made by DEP. As noted above, since the AGO and CUCA, as well as other parties that did not provide testimony on ROE, did not agree to the settlements the Commission is required to examine the Stipulations and exercise its independent judgment to arrive at its own independent conclusion as to the proper ROE.

The starting point for an examination of what constitutes a reasonable ROE begins with the various economic and financial analyses provided by the parties' expert witnesses. In this proceeding those analyses were provided in the testimonies of six different witnesses. These testimonies, as summarized above, provide a relatively broad range of methods, inputs, and recommendations regarding the proper ROE determination for DEP. For example, witness D'Ascendis relied in his direct testimony on multiple analyses to arrive at his ROE recommendation. These analyses were a Constant Growth DCF Analysis, a Capital Asset Pricing Model analysis, an Empirical Capital Asset Pricing Model, a Bond Yield Plus Risk Premium analysis, and an Expected Earnings analysis. By way of comparison, Public Staff witness Woolridge and AGO witness Baudino relied upon DCF analyses and CAPM analyses in reaching their conclusions; however, the inputs utilized by these witnesses in their analyses are different from those utilized by witness D'Ascendis. Commercial Group witness Chriss recommended that the Commission look at the proposed ROE in light of recent ROEs approved by the Commission and by commissions nationwide. Similarly, CIGFUR witness Phillips looked at the average allowed ROEs for both vertically integrated and distribution-only electric utilities of 9.73% and recommended that average as a cap to the allowed ROE. Finally, CUCA witness

O'Donnell proposed an ROE of 8.75% using the DCF and CAPM methodologies, as well as a comparable earnings approach.

These varying analyses, as is typical, produced varying results. Witness D'Ascendis' analyses prompted him to propose an ROE range of 10.00% to 11.00% with a specific ROE recommendation of 10.50%. Witness Woolridge's analyses resulted in a recommended ROE range of 6.70% to 8.40% with a primary recommendation of a 9.00% ROE with a 50% common equity and 50% debt capital structure and a secondary recommendation of an 8.40% ROE if DEP's proposed capital structure of 47.00% long-term debt and 53.00% common equity was approved. AGO witness Baudino proposed an ROE of 9.00%. Finally, as noted above, witness O'Donnell recommended a ROE of 8.75%, and witness Phillips a cap on ROE of 9.73%.

The Commission finds the cost of equity analyses helpful in reaching its conclusion on an appropriate ROE for DEP but notes that the outputs of the various analyses span a range from 6.70% to 15.70% and the specific ROE (primary) recommendations of the witnesses span a range from 8.75% on the low end to 10.50%[7] on the high end.

The Commission finds that the updated DCF, Bond Yield Risk Premium, and Expected Earnings analyses of DEP witness D'Ascendis, the Second Partial Stipulation, and the other intervenor settlements are credible, probative, and entitled to substantial weight.

DEP witness D'Ascendis in his supplemental rebuttal testimony provided his constant growth DCF analyses, as shown on Supplemental Rebuttal Ex. DWD-1, pages 1 and 2 as follows: 30-day dividend yield high ROE mean 9.67%, median 9.42%; and 90-day dividend yield high ROE mean 9.57%. The Commission finds witness D'Ascendis' constant growth DCF analyses mean and median ROE results credible, probative, and entitled to substantial weight.

DEP witness D'Ascendis' updated Bond Yield Plus Risk Premium, as shown on Supplemental Rebuttal Ex. DWD-5, using the current 30-year Treasury yield of 1.47%, the near term projected 30-year Treasury yield of 1.72%, and the long-term projected Treasury yield of 3.40% and applying it to the approved ROEs in 1,630 electric utility rate proceedings between January 1980 and June 30, 2020, results in ROEs of 10.25%, 10.08%, and 9.96%, respectively. While in the past, the Commission has generally approved the use of current interest rates rather than projected near-term or long-term interest rates in this particular case disequilibrium in the current markets as discussed by witness Woolridge give the Commission reason to look beyond the current Treasury yields and give some weight to projected rates. The Commission finds witness D'Ascendis' updated Bond Yield Plus Risk Premium analyses using the current and

[7] As noted *infra*, DEP witness D'Ascendis recommended an ROE of 10.50% but DEP requested a lower ROE of 10.30% to mitigate the impact of the rate increase on customers.

projected 30-year Treasury yields to be credible, probative, and entitled to substantial weight.

DEP witness D'Ascendis' Expected Earnings approach produced a range from 5.50% to 13.56% with a mean of 10.18% and a median of 10.55%. Supplemental Rebuttal Ex. DWD-6. In prior cases, the Commission has given weight to this methodology, which stands separate and apart from the market-based methodologies (e.g., the DCF or CAPM) also used by ROE experts. *See, e.g.*, 2013 DEC Rate Order at 36. The Commission chooses to do so again in this case.

In this case the Commission is concerned that the ROE recommended by CUCA witness O'Donnell, and to a lesser extent the ROE recommended by AGO witness Baudino, would, when translated into rates and holding all other things equal, fail the *Hope* "end results" test. This is shown graphically in Chart 1 of D'Ascendis' Rebuttal Testimony. Tr. vol. 11, 354. The Commission agrees with witness D'Ascendis that this could result in investors receiving a lower return with greater risk than would be available from other utilities, thereby making it more costly to raise capital. The Commission agrees with witness D'Ascendis that the ROE recommendations of witnesses Baudino and O'Donnell are unduly low, places great weight upon this observation, and therefore finds the Baudino and O'Donnell ROE recommendations to be unpersuasive. In doing so, the Commission emphasizes that it is referencing the data concerning other authorized ROEs as a means to test the ROE recommendations of witnesses Baudino and O'Donnell, and not as a reference to or reliance upon the doctrine of "gradualism." *See Cooper II*, 367 N.C. at 443.

Witnesses Baudino and O'Donnell recommended ROEs of 9.00%, and 8.75%, respectively. These recommendations are below the band of authorized ROE results set out in D'Ascendis' Chart 1. These recommendations are also below the stipulated 9.90% ROE from the Company's previous rate case or 10.20% from the rate case prior to that. The recommendations of witnesses Baudino and O'Donnell are also inconsistent with those recently authorized in North Carolina. The Commission has most recently authorized an ROE of 9.75% for Dominion Energy North Carolina; 9.90% for the Company and DEC in their prior rate cases, 9.70% for Piedmont Natural Gas, and 9.40% for Aqua America. Witness D'Ascendis indicated, and the Commission agrees, that these witnesses' recommendations are far below the average and median ROE for vertically integrated electric utilities in jurisdictions rated in the top third by Regulatory Research Associates, which range from 9.37% to 10.55%. Witnesses Baudino and O'Donnell's recommendations are below those of other vertically integrated utilities similarly rated from 2015 through 2020, while the settled ROE of 9.60% does fall within that ROE range.

In his direct testimony, witness Baudino testified that his 9.00% ROE recommendation was "reasonably close to recently allowed ROEs", using a 9.68% average ROE determination by commissions in 2017 as "recently allowed ROEs." Witness Baudino contended on cross-examination that "[this 68-point differential] was reasonable." Tr. vol. 2, 136. The differential between the stipulated ROE (9.60%) and witness Baudino's 9.00% ROE recommendation is 60 basis points – less than the 68 basis points witness Baudino deemed "reasonable."

There are other aspects of these witnesses' analyses that the Commission finds lacking. For example, the Commission finds questionable witness Baudino's failure to adjust his ROE recommendation in his supplemental direct testimony considering the recent volatility in the markets, increase in betas for the companies in the proxy group, and the higher DCF results in his supplemental testimony. Additionally, the Commission agrees with witness D'Ascendis' criticism of witness Baudino's growth rates applied to the Constant Growth DCF model, and his reliance on the Constant Growth DCF model to determine the Company's ROE, as well as the reasonableness of his Bond Yield Plus Risk Premium analysis among other factors. Finally, the Commission also gives no weight to witness Baudino's CAPM approach as witness Baudino himself disregarded its unreasonably low results.

Regarding the ROE recommendation of CUCA witness O'Donnell, like with witness Baudino, his reliance on historical growth rates in his DCF analysis does not adequately encapsulate how the model is a forward-looking measure of investors' expectations. Further, the Commission finds compelling witness D'Ascendis' test of the relationship between retention ratios and future growth rates demonstrating that earnings growth actually *decreased* as the retention ratio increased, thereby undermining the premise underlying witness O'Donnell's use of the Retention Growth Model. As for witness O'Donnell's Comparable Earnings Approach, his forward-looking 2019 and 2022–2025 analysis yielding ROE estimates of 10.0% to 10.6% for his proxy group was similar to witness D'Ascendis' updated Expected Earnings analysis of 10.18% to 10.55%. Overall, it seems that witness O'Donnell's 8.75% ROE estimate is at odds with the data he presented.

Additionally, witness D'Ascendis testifies that the intervenor witnesses fail to recognize the risks faced by the Company and do not appropriately reflect the evolving capital market environment. Tr. vol. 11, 351. A significant departure from the authorized ROEs of other similarly situated utilities impacts the Company's ability to compete with other companies for long-term capital to provide safe and reliable utility service. The Commission notes the risk that an ROE in the range recommended by witnesses Baudino and O'Donnell could impact the Company's ability to compete for capital, as illustrated by witness D'Ascendis in his discussion of a recent rate decision in which the financial community responded negatively to an adverse regulatory outcome for CenterPoint Energy Houston Electric.

In sum, and in light of all of the factors discussed in this Order, the Commission places minimal weight upon the ROE recommendations of witnesses O'Donnell and Baudino. Rather, the Commission finds the stipulated ROE to be reasonable and appropriate, as well as supported by the substantial weight of the evidence presented. As witness D'Ascendis notes in his second settlement testimony, the average authorized ROE for vertically integrated electric utilities from 2016 to June 2020 was 9.74%, 14 basis points above the stipulated ROE.

The Commission, of course, does not blindly follow ROE results allowed by other commissions. The Commission determines the appropriate ROE based upon the evidence and particular circumstances of each case. However, the Commission believes that the ROE trends and decisions by other regulatory authorities deserve some consideration, as (1) they provide a check or additional perspective on the case-specific circumstances, and (2) the Company must compete with other regulated utilities in the capital markets, meaning that an ROE significantly lower than that approved for other utilities of comparable risk would undermine the Company's ability to raise necessary capital, while an ROE significantly higher than other utilities of comparable risk would result in customers paying more than necessary. Both of those outcomes are undesirable and would result in unjust and unreasonable rates. The fact that the approved ROE falls 14 basis points below the average and within the range of recently approved ROEs for other vertically integrated electric utilities lends additional support to the Commission's approval.

DEP witness D'Ascendis in his supplemental rebuttal testimony provided his constant growth DCF analyses, as shown on Supplemental Rebuttal Ex. DWD-1, pages 1 and 2: 30-day dividend yield high ROE mean 9.67%, median 9.42%; and 90-day dividend yield high ROE mean 9.57%. Although the Commission does not approve of witness D'Ascendis' using only analysts' predicted earnings per share to determine the DCF growth rate, the Commission finds witness D'Ascendis' constant growth DCF analyses mean and median ROE results to be credible, probative, and entitled to substantial weight.

DEP witness D'Ascendis' updated Bond Yield Plus Risk Premium, as shown on Supplemental Rebuttal Ex. DWD-5, using the current 30-year Treasury yield of 1.47%, the near term projected 30-year Treasury yield of 1.72%, and the long-term projected Treasury yield of 3.40% and applying it to the approved ROEs in 1,630 electric utility rate proceedings between January 1980 and June 30, 2020, results in ROEs of 10.25%, 10.08%, and 9.96%, respectively. While in the past the Commission has generally approved the use of current interest rates rather than projected near-term or long-term interest rates, in this particular case current disequilibrium in the market gives the Commission reason to look beyond the current Treasury yields and give some weight to projected rates. The Commission finds witness D'Ascendis' updated Bond Yield Plus Risk Premium analyses using the current and projected 30-year Treasury yields to be credible, probative, and entitled to substantial weight.

The record contains substantial evidence supporting the reasonableness of the stipulated ROE of 9.60%. The Commission notes generally that this ROE is well within the range of recommended returns by the economic experts in this docket of 8.75% to 10.50%. More specifically, an ROE of 9.60% falls within D'Ascendis' range under his constant growth DCF analyses and his Expected Earnings Analysis. Supplemental Rebuttal Ex. DWD-6. In prior cases, the Commission has given weight to this methodology, which stands separate and apart from the market-based methodologies (*e.g.,* the DCF or CAPM) also used by ROE experts. *See, e.g.*, 2013 DEC Rate Order at 36. The Commission chooses to do so again in this case. Moreover, 9.60% falls squarely within the range and very close to the average of recently allowed ROEs for vertically integrated electric utilities nationally. Lastly, the Commission notes that the stipulated ROE is 70 basis points lower than the ROE the Company requested in its Application. As such, the Commission concludes that 9.60% is within the “zone of reasonableness” that leading commentators and the North Carolina Supreme Court have indicated is presumptively just and reasonable. *See State ex rel. Utils. Comm’n v. Gen. Tel. Co. of the Southeast*, 285 N.C. 671, 681 (1974) (a “zone of reasonableness extending over a few hundredths of one percent” exists within which the Commission may appropriately exercise its discretion in choosing a proper ROE).

As the Supreme Court made clear in *CUCA I* and *CUCA II*, the Commission should give full consideration to a nonunanimous stipulation itself, along with all evidence presented by other parties, in determining whether the stipulation’s provisions should be accepted. In this case, insofar as expert ROE testimony is concerned, both witness D’Ascendis and witness Woolridge support an ROE at 9.60%. Tr. vol. 11, 620 (D’Ascendis); tr. vol. 15, 695-96 (Woolridge). The Commission notes that the other intervenor settlements, as amended, also supported the use of an ROE of 9.60%. Only witness Baudino questioned the settlement ROE. Tr. vol. 2, 133. But, as discussed above, the Commission places very little weight upon his ROE recommendation. Thus, the Commission finds and concludes that the Second Partial Stipulation, the other intervenor settlements as amended, along with the expert testimony of witnesses D’Ascendis and Woolridge, is credible evidence of the appropriate ROE and is entitled to substantial weight in the Commission’s ultimate determination of this issue.

In summary, the Commission concludes there is substantial evidence supporting the reasonableness of an ROE of 9.60%.

However, to meet its obligation in accord with the holding in *Cooper I*, the Commission will next address the impact of changing economic conditions on customers. In this case, all parties had the opportunity to present the Commission with evidence concerning changing economic conditions as they affect customers. The testimony of witnesses D’Ascendis, Woolridge, and Baudino, which the Commission finds entitled to substantial weight, addresses changing economic conditions at some length. Witness D’Ascendis provided detailed data concerning changing economic conditions in North Carolina, as well as nationally, and concluded that the North Carolina-specific conditions are “highly correlated” with conditions in the broader nationwide economy. As such, witness D’Ascendis testified that changing economic conditions, both nationally and specific to North Carolina, are reflected in his ROE estimates.

Public Staff witness Woolridge agreed with DEP witness D’Ascendis that as of the time of the filing of his testimony, economic conditions had improved in North Carolina. He pointed out that at the time of the filing of his testimony that while the unemployment rates in North Carolina and DEP’s service territory have fallen since their peaks in the 2009-2010 period, they are both above the national average of 3.90%. Witness Woolridge also noted that while North Carolina’s residential electric rates are below the national average, its median household income is more than 10% below the U.S. norm.

Yet subsequent to the filing of this case, and as a result of the COVID-19 pandemic, economic conditions deteriorated in North Carolina and across the country during the first half of 2020. The Commission gives weight to the testimony of witness Baudino regarding the national decline of the GDP in the first quarter of 2020 by 5.0% as unemployment rose to 12.90% and 13.30% in in May in North Carolina and the US, respectively. The Commission likewise gives weight to the testimony of witness D'Ascendis regarding the national and State unemployment rates in July of 10.2% and 8.5%, respectively, reflecting a quick rebound of at least some of the economic activity lost during the downturn.

As the Commission has noted, customer impact due to changing economic conditions is embedded in ROE expert witness analyses. For example, Witness D'Ascendis' analysis, which the Commission credits and to which the Commission gives weight, also indicates that even though the North Carolina and U.S. economies have contracted, economic conditions in North Carolina continue to be highly correlated to conditions nationally, and, therefore, continue to be reflected in the analyses used to determine the allowed ROE. Witness D'Ascendis' testimony regarding correlation between U.S. and North Carolina GDP growth for the fifteen years and four quarters ended March 2020, and employment in the US and DEC's service territories from February to May 2020, demonstrate these high correlations. The Commission also observes that witness D'Ascendis' testimony that North Carolina's economy had been affected somewhat less severely than the national economy and its economic recovery had been somewhat more rapid.

Therefore, the Commission determines that the econometric data relied upon by ROE expert witnesses sufficiently captures the effects and impacts of changing economic conditions upon customers.

Based upon the general state of the economy and the need for the continuing affordability of electric utility service, and after weighing and balancing factors affected by the changing economic conditions in making the subjective decisions required, the Commission concludes that the stipulated ROE of 9.60% will not cause undue hardship to customers even though, the Commission acknowledges, some customers will struggle to pay for electric utility service.

Many of the adjustments to the Company's proposed rate increase reduce ratepayer responsibility and equity investor returns in compliance with the Commission's responsibility to establish rates as low as reasonably permissible without transgressing constitutional constraints, and thus, inure to the benefit of consumers' ability to pay their bills in this economic environment.[8] For example, to the extent the Commission made

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[8] The Commission notes that consumers pay "rates," a charge in cents per kilowatt-hour (kWh) for the electricity they consume. They do not pay a "rate of return on common equity," though it is a component of the Company's cost of providing service, which is built into the charge per kWh. Investors are compensated by earning a return on the capital they invest in the business. Per the Commission determination of the ROE in this matter, investors will have the opportunity to be paid in dollars for the dollars they invested at the rate of 9.60%.

downward adjustments to rate base, disallowed test year expenses, increased test year revenues, or reduced the equity capital structure component, the Commission reduced the rates consumers will pay during the future period when rates will be in effect. In this case, the Commission has ordered negative adjustments to many expenses sought to be included in the Company's revenue requirement. Because the compensation owed to investors for investing in the Company's provision of service to consumers takes the form of return on investment, downward adjustments to rate base, disallowances of test year expenses, increases to test year revenues, or reduction in the equity capital structure component will reduce investors' return on investment irrespective of the determination of ROE.

The Commission has also approved herein an annual $2.5 million shareholder contribution to the Neighbor Energy Fund in 2021 and 2022, as provided in the Second Partial Stipulation, and an annual contribution of $3 million, in conjunction with DEC, to the Helping Home Fund in 2021 and 2020, for a total contribution of $11 million of the Company's shareholder funds for energy assistance to low-income customers. NCSEA/NCJC et al. Stipulation, § IV. These decisions directly benefit customers with the least ability to pay in the current economic environment. The Commission takes these facts into account when approving the 9.60% ROE.

The Commission also recognizes that the Company is in a significant construction mode, and much of the associated investment is for generation, transmission, and distribution infrastructure to benefit DEP's customers, as well as in response to recent increases in environmental compliance costs and other operating expenses. The need to invest significant sums to serve its customers requires the Company to maintain its creditworthiness in order to compete for large sums of capital on reasonable terms. The Commission must weigh the impact of changing economic conditions on DEP's customers against the benefits that those customers derive from the Company's ability to provide safe, adequate, and reliable electric service. Safe, adequate, and reliable electric service is essential to the well-being of the people, businesses, institutions, and economy of North Carolina. Thus, the Commission finds and concludes that such capital investments by the Company provide significant benefits to all of DEP's customers.

The Commission concludes in the exercise of its independent judgment and discretion that a 9.60% ROE is supported by the greater weight of the evidence and should be adopted. The hereby approved ROE appropriately balances the benefits received by DEP's customers from DEP's provision of safe, adequate, and reliable electric service in support of the well-being of the people, businesses, institutions, and economy of North Carolina (which benefits are symbiotically linked to the Company's ability to compete in the equity capital market to access capital on reasonable terms that will be fair to ratepayers) with the difficulties that some of DEP's customers will experience in paying DEP's adjusted rates. The Commission further concludes that a 9.60% ROE will allow DEP to compete in the market for equity capital, providing a fair return on investment to its investor-owners, and that the lowering of the rate from the requested 10.30% to 9.60% has the effect of lowering the cost of service which forms the basis of the rates the ratepayers must pay for service. Accordingly, the Commission concludes, accounting for changing economic conditions and their impact on customers, that the approved ROE will result in the lowest rates constitutionally permissible in this proceeding.

Finally, in approving the 9.60% ROE, the Commission gives significant weight to the stipulations and the benefits that they provide to DEP's customers, which the Commission is obliged to consider as an independent piece of evidence under the Supreme Court's holding in *CUCA I*.

As a result, the Commission concludes that the 9.60% stipulated ROE is reasonable and appropriate and is supported by the greater weight of the substantial evidence in the record.

B. Capital Structure

Summary of the Evidence

In DEP's Application witness Newlin proposed using a capital structure of 53% members' equity and 47% long-term debt. Tr. vol. 11, 633. Witness Newlin testified that the Company's "specific debt/equity ratio will vary over time, depending on a variety of factors, including among other things, the timing and size of capital investments and payments of large invoices, debt issuances, seasonality of earnings, and dividend payments to the parent company." *Id.* at 648. As of December 31, 2019, DEP's capital structure was 52% common equity and 48% long-term debt. *Id.* at 661.

In his direct testimony CUCA witness O'Donnell recommended that the Commission reject the Company's capital structure proposal and instead advocated for a 50/50 capital structure. Tr. vol. 14, 133. Witness O'Donnell's analysis supporting his 50/50 capital structure recommendation was based on his comparison of capital structures of publicly traded holding companies, not operating utility companies. *Id*. at 237-38.

Public Staff witness Woolridge testified that the Company's proposed capital structure included more common equity than the average of the proxy group he used in conducting his analysis. Tr. vol. 15, 563. He stated that it is appropriate to use the common equity ratios of the parent holding companies and that the high debt ratio and low equity ratio of DEP's parent company, Duke Energy, is credit negative for DEP as evaluated by Moody's. *Id*. at 566-67. He noted, however, that because DEP is a regulated business, it is exposed to less business risk and can carry relatively more debt in its capital structure than most unregulated companies, like Duke Energy. *Id*. at 569. Witness Woolridge further testified that DEP should take advantage of its lower business risk to employ cheaper debt capital at a level that will benefit its customers through lower revenue requirements. *Id*. at 569. Therefore, witness Woolridge recommended a 50/50 capital structure based on a 9.00% ROE. *Id*. at 571. Witness Woolridge also made an alternative capital structure recommendation of the Company's proposed structure of 47% long-term debt and 53% common equity based on an 8.40% ROE. *Id*. at 572.

AGO witness Baudino recommended that the Commission reject the Company's requested ratio and instead recommended the Commission approve the Company's December 2018 capital structure, which includes a common equity of 51.50%. Tr. vol. 13, 445, 511. As noted above, witness Baudino's recommendation is lower than the Company's recent actual capital structure of 52% equity and 48% long-term debt.

In rebuttal witness Newlin pointed out that CUCA witness O'Donnell utilized data showing capital structures that were inappropriate to use because they do not differentiate between various types of utility companies, which present different risk profiles. Tr. vol. 11, 661. Witness D'Ascendis testified that parent and operating companies do not necessarily have the same capital structures because financing at each level is driven by "the specific risks and funding requirements associated with their individual operations." *Id*. at 469. He noted the Commission's previous rejection of the use of parent company structures as opposed to operating company structures in determining the operating utility's appropriate equity/debt ratio. *See* Order Accepting Stipulation, Deciding Contested Issues, and Granting Partial Rate Increase, *Application by Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, No. E-2, Sub 1142, at 87-88 (Feb. 23, 2018) (2018 DEP Rate Order), *aff'd in part, and remanded in part*, *State ex rel. Utils. Comm'n v. Stein*, 375 N.C. 870, 851 S.E.2d 237 (2020); Order Granting General Rate Increase and Approving Amended Stipulation, *Application of Duke Energy Carolinas, LLC, for an Increase in and Revisions to Its Rates and Charges Applicable to Electric Utility Service in North Carolina*, No. E-7, Sub 909, at 27-28 (Dec. 7, 2009) (2009 DEC Rate Order).

In addition witness D'Ascendis noted the use of the operating subsidiary's actual capital structure – that is, the capital actually funding the utility operations that provide service to customers – is entirely consistent with precedent of the Federal Energy Regulatory Commission (FERC), so long as three criteria are met: the operating subsidiary (1) issues its own debt without guarantees; (2) has its own bond rating; and (3) has a capital structure within the range of capital structures for comparable utilities. *Id*. at 483-84. Witnesses Newlin and D'Ascendis testified that DEP, which issues its own debt and has its own bond rating, has a capital structure that is generally consistent with that of other operating companies, especially vertically integrated companies. *Id*. at 673 (Newlin); *id*. at 568 (D'Ascendis). Further, in response to witness O'Donnell, witness D'Ascendis testified that by excluding equity ratios authorized in jurisdictions that include non-investor supplied capital in the capital structure, witness O'Donnell's review demonstrated an average and median authorized equity ratio in 2019 of 52.08% and 52% for vertically integrated utilities. *Id*. at 568. Thus, he noted that the stipulated 52% equity ratio is consistent with authorized equity ratios. *Id*. at 624. DEP witness Newlin also pointed out that witness O'Donnell considers jurisdictions in which non-investor supplied capital is included in the capital structure, thus biasing his review. *Id*. at 660.

Subsequent to the filing of testimony, the Company reached several stipulations with the Public Staff, CIGFUR, the Commercial Group, Harris Teeter, Vote Solar, NCSEA and NCJC et al. agreeing that the rates in this proceeding should be set using a capital structure of 52% common equity and 48% long-term debt, including in the Public Staff's

Second Partial Stipulation. The 52% equity capital structure agreed to in these settlement agreements represent a compromise between the Company's 53% equity position and the intervenors' recommendations ranging from a 50% to a 51.50% equity capital structure.

In their testimony supporting the stipulations Company witness Newlin and Public Staff witness Woolridge testified that the capital structure reflected in the Second Partial Stipulation represents a compromise by both parties in an effort to reach agreement and is in the public interest. Witness De May's second settlement testimony also supported the stipulated 52% equity capital structure. Tr. vol. 11, 794.

Discussion and Conclusions

In evaluating the evidence on capital structure in this proceeding the Commission first notes that the equity/debt ratios reflected in the Second Partial Stipulation and the stipulations with CIGFUR, the Commercial Group, Harris Teeter, Vote Solar, NCSEA and NCJC et al. of 52% equity and 48% long-term debt are consistent with and within the prior decisions of the Commission.[9] That consistency is not a determinative factor from the Commission's perspective but the prior decisions do provide some context supporting the reasonableness of the stipulated capital structure.

Based upon its own review and independent analysis of the evidence the Commission concludes that a capital structure of 52% equity and 48% long-term debt, as is reflected in Section III.B of the Second Partial Stipulation and the stipulations with CIGFUR, the Commercial Group, Harris Teeter, Vote Solar, NCSEA and NCJC et al. is just and reasonable and appropriate for use in this proceeding on several grounds.

First, this capital structure is the same capital structure authorized for DEP in its last rate case. Second, this capital structure was accepted by the Public Staff, CIGFUR, the Commercial Group, Harris Teeter, Vote Solar, NCSEA and NCJC et al. in separate stipulations. Third, the Commission gives great weight to Company witness Newlin's testimony that the stipulated capital structure is reasonable and appropriate when viewed in the context of the overall Second Partial Stipulation. Fourth, the Commission places great weight as well on witness Woolridge's conclusion that the end result of the settlement is fair and reasonable with respect to both ratepayers and shareholders, and that customers will benefit from lower rates as a result of a negotiated settlement. Fifth, the Commission also gives weight to the Second Partial Stipulation and the benefits that it provides to DEP's customers, which the Commission is obliged to consider as an independent piece of evidence under *CUCA I* and *II*. Each party to the Second Partial Stipulation gained some benefits that it deemed important and gave some concessions for those benefits. Based on the Application and prefiled testimony, it is apparent that the

[9] *See* DENC Sub 532 Order (51.75% common equity and 48.25% debt); PSNC Sub 565 Order (52.0% common equity, 44.62% long-term debt, 3.38% short-term debt); PNG Sub 743 Order (52.00% equity, 47.15% long-term debt, 0.85% short-term debt); DEC Sub 1146 Order (52% common equity and 48% long-term debt); DEP Sub 1142 Order (52% common equity and 48% long-term debt); DENC Sub 562 Order (52% common equity and 48% long-term debt).

Second Partial Stipulation ties the 52% equity and 48% long term debt capital structure to substantial concessions the Company made to reduce its revenue requirement. Sixth, and finally, the Commission gives weight to the stipulations with CIGFUR, the Commercial Group, Harris Teeter, Vote Solar, NCSEA and NCJC et al. as it did to the Second Partial Stipulation.

Accordingly, based on the matters set forth above and in the exercise of its independent judgment, the Commission finds that a preponderance of the evidence weighs in favor of the stipulated capital structure pursuant to Section III.B of the Second Partial Stipulation and the stipulations with CIGFUR, the Commercial Group, Harris Teeter, Vote Solar, NCSEA and NCJC et al. and that such capital structure is just, reasonable, and appropriate for use in setting rates in this docket.

C. Cost of Debt

DEP witness Newlin testified that the Company's long-term debt cost as of December 31, 2018, was 4.15%, which was the value used to determine the revenue requirement in the Company's Application. As part of Section III.B of the Second Partial Stipulation, DEP and the Public Staff agreed to use in determining the revenue requirement the May 2020 embedded cost of debt of 4.04%. The Commission finds for the reasons set forth herein that 4.04% cost of debt is just and reasonable.

In his direct testimony Public Staff witness Woolridge initially proposed a cost of long-term debt of 4.11%, DEP's long-term debt cost as of December 31, 2019, and DEP thereafter updated its cost of debt to 4.11% in supplemental testimony filed July 10, 2020. Tr. vol. 15, 696. As part of the give-and-take negotiations involved in the settlement process, DEP and the Public Staff agreed to a cost of long-term debt of 4.04%, DEP's long-term debt cost updated through May 2020. *Id.*

No intervenor offered any evidence to contradict the use of 4.04% as the cost of debt. The Commission therefore finds and concludes that the use of a debt cost of 4.04% per the terms of Section III.B of the Second Partial Stipulation is supported by the greater weight of the substantial evidence and is just and reasonable to all parties in light of all the evidence presented.

D. Credit Metrics

Summary of the Evidence

DEP Direct Testimony

Witness Newlin

DEP witness Newlin testified that his responsibilities as Senior Vice President, Corporate Development and Treasurer for Duke Energy include managing Duke Energy and its subsidiaries' credit ratings and interactions with major credit rating agencies. His testimony addressed DEP's financial objectives, capital structure, cost of capital, credit ratings, and forecasted capital needs. Witness Newlin emphasized the importance of DEP's continued ability to meet its financial objectives. He stated that the Company's proposed rate increase will allow it to recover prudently incurred costs, compete in the capital markets for needed capital, and preserve its financial standing with both debt and equity investors, as well as the credit rating agencies, to the long-term benefit of its customers. Tr. vol. 11, 628-631.

Witness Newlin testified that DEP has substantial capital needs over the next several years and that financial strength and access to capital at all times are necessary for DEP to provide service to its customers. To maintain its financial strength and flexibility, including its strong investment grade credit ratings, DEP has specific objectives including: (1) maintaining at least 53 percent common equity; (2) ensuring timely recovery of prudently incurred costs; (3) maintaining sufficient cash flows to meet obligations; and (4) maintaining a sufficient return on common equity to fairly compensate shareholders. *Id*. at 631.

Witness Newlin explained credit quality and credit ratings and how they are determined by the two major credit ratings agencies, Standard & Poor's (S&P) and Moody's Investor Service (Moody's). In assessing credit quality, these agencies consider many qualitative and quantitative factors in assigning credit ratings. Qualitative factors may include DEP's regulatory climate, its track record for delivering on commitments, strength of management, its operating performance, and the economic vitality and customer profile of its service area. Quantitative measures are primarily based on operating cash flow and focus on the level at which DEP maintains financial leverage in relation to its generation of cash and its ability to meet its fixed obligations based on internally generated cash, such as its debt to capital ratio. Witness Newlin also provided the credit ratings by S&P and Moody's on DEP's outstanding debt, as of October 30, 2019, which show that DEP carries a credit rating compatible with strong, investment-grade securities, subject to low risk for an investor. *Id*. at 634-35.

However, according to his testimony the ratings agencies have identified several challenges that DEP faces in maintaining its current credit ratings. These include downward pressure on credit metrics due to regulatory lag in the recovery of coal ash basin closure costs, reduced cash flows due to federal tax reform, and elevated capital expenditures. He elaborated that the Federal Tax Cut and Jobs Act of 2017 (Tax Act) resulted in electric utilities, including DEP, and their holding companies losing some of their cash flow from deferred taxes on an ongoing basis. He testified that this loss of cash flow would reduce DEP's funds from operations to debt ratio (FFO/Debt), a key credit metric. Because DEP's EDIT are customer-supplied funds, he testified that DEP proposes to flow the EDIT, not subject to a statutory required flowback period, over twenty years. In his opinion, a twenty-year period balances both the interest of customers and the financial strength of the Company and would smooth out the reduction in cash flow to DEP as it returns the EDIT to customers. *Id*. at 637-45.

Public Staff Testimony

Witness Hinton

Public Staff witness Hinton testified to address concerns raised by Company witnesses Newlin and De May with regards to the credit metrics and the risk of a downgrade of DEP's credit ratings. He also testified in support of the Public Staff's recommended flowback of unprotected EDIT over a five-year period. Tr. vol. 17, 324.

Witness Hinton testified that DEP had provided the Public Staff with projected FFO/Debt credit metrics using both the five-year flowback period for unprotected EDIT recommended by the Public Staff and the twenty-year flowback recommended by DEP. He noted that in Moody's March 28, 2019, Credit Opinion for DEP, an FFO/Debt metric that is between 21% to 23% qualifies for an "A" rating. He testified that the FFO/Debt metric would only be below 21% in 2020 with a five-year flowback. In his opinion, a temporary decrease in FFO/Debt would not likely lead to a downgrade of the Company's "Aa3" ratings on its first mortgage bonds or its "A2" senior unsecured bonds. Based on his analyses, he believed that unexpected financial developments would have to occur that reduced DEP's cash flow from operations or caused the Company to issue more debt to trigger a downgrade. In addition, he testified that Moody's and S&P place weight on factors other than credit metrics and that DEP has other means to finance the EDIT flowback over the five-year period, such as equity. Finally, witness Hinton testified that even if DEP were to be downgraded by one notch to "A3," it is reasonable to expect that the investor-required bond yield would increase by 10 basis points under current market conditions. *Id*. at 324-31.

DEP Rebuttal Testimony

Witness Newlin

In rebuttal DEP witness Newlin testified that he disagreed with Public Staff witness Hinton's advocacy for a five-year flowback of unprotected EDIT instead of the twenty-year period proposed by the Company. He stated that reducing the Company's cash flow through a more accelerated flowback of unprotected EDIT at the same time that DEP is investing in large capital projects and refinancing obligations will negatively impact its credit metrics, which must be taken into account. Witness Newlin noted that in March 2020, Moody's in its Credit Opinion of DEP identified tax reform as one of the several factors that could adversely impact the Company's financial metrics (specifically, cash flow coverage ratios). Tr. vol. 11, 678-79.

Witness Newlin testified that it is reasonable that customers should benefit from the Tax Act. However, he submitted that without the Commission's thoughtful consideration regarding all aspects of the Tax Act, particularly through a reduction in cash flow, the Company's credit quality could be adversely affected. He stated that an accelerated return of EDIT over an arbitrary five-year period would adversely impact the Company's cash flow and FFO/Debt ratio. Furthermore, witness Hinton's analysis focuses on EDIT flowback in isolation and does not consider the cumulative impact of other credit negative proposals by the Public Staff including a lower return on equity, a more leveraged capital structure, disallowance of a return on coal ash costs, and other recommendations for ratemaking that would reduce cash flows and increase debt. *Id*. at 680-82.

Witness Newlin also testified that witness Hinton's estimate of a 10-basis point increase in debt cost as a result of a downgrade is based on capital market conditions reflecting historically low interest rates and near record tight credit spreads. He testified that credit spreads can widen significantly during periods of uncertainty and market volatility. Witness Newlin noted that Moody's mentions a downgrade would occur if FFO/Debt is below 20% on a sustained basis. However, witness Newlin testified that an upgrade would require significantly higher metrics and would require approximately $250 million in incremental annual cash flows on a sustained basis with no additional leverage to achieve a 25% FFO/Debt ratio which would likely require significant rate increases over prolonged periods. *Id*. at 685-87.

Witness Young

DEP witness Steven Young, Executive Vice President and Chief Financial Officer for Duke Energy, testified in rebuttal on the financial needs of Duke Energy investors, the impact of utility regulation on the Company's credit profile and investors, the benefits to customers of having a financially healthy utility, the Company's concerns with some of the proposals offered by intervenors in this proceeding (and with the Commission's recent Dominion Energy North Carolina Order issued in Docket No. E-22, Sub 562 and Sub 566), and the reasons those proposals should not be adopted by the Commission in this proceeding. Tr. vol. 11, 702-03.

Witness Young testified that neither Duke Energy nor DEP has access to any established "reserves" to pay the carrying costs of unavoidable debt (and supply equity) needed to support utility operations. He testified that having to simply absorb those carrying costs could have significant negative implications to the financial stability of the enterprise as a whole. Witness Young explained that energy utility operations are often cash flow negative due to the need to serve a growing customer base, repair and maintain existing infrastructure, and immediately respond to all service interruptions such as those caused by major storms. Duke Energy's ability to fund these investments is based upon investor confidence that customer rates will be set at levels that allow all prudent utility operating and financing costs to be recovered. *Id*. at 705-07.

Witness Fetter

DEP rebuttal witness Fetter, a consultant of DEP, testified mainly in response to the Public Staff's recommendation for an equitable 50/50 sharing of CCR compliance costs. Utilizing his past experience as a state utility commission chairman and head of the utility rating practice at Fitch, Inc., he discussed how the adoption of such a recommendation would be inappropriate and viewed negatively by the credit rating agencies and investors. Tr. vol. 26, 74.

Witness Fetter testified that DEP corporate issuer credit ratings span between the middle level (A2, Stable outlook at Moody's) and the lowest level (A-, Stable outlook at S&P) of the "A" category. He testified that a regulated utility should endeavor to hold no lower than Baa1 (Moody's) to BBB+ (S&P), with a longer-term goal of moving into or maintaining the A category. *Id*. at 51.

Witness Fetter testified that the most qualitative factors used by rating agencies are regulation, management, and business strategy, along with access to energy, gas, and fuel supply with timely recovery of associated costs. He testified that credit rating agencies look for the consistent application of sound economic and regulatory principles by utility regulators. *Id*. at 53-54.

Witness Fetter testified that the financial community's view of the Commission has been relatively positive. He testified that Regulatory Research Associates (RRA) currently rates the North Carolina regulatory environment, which goes beyond the Commission to also include legislative and executive branch policies, as Average 1, among the top one-third of the 53 regulatory jurisdictions currently rated by RRA. He testified that RRA's view of North Carolina's regulation as overall relatively constructive from an investor viewpoint serves as a positive factor in the credit rating analytical process *Id*. at 58-59.

Witness Fetter testified that Moody's cautions that a DEP credit downgrade could occur if there is a decline in the credit supportiveness of DEP's regulatory relationships, particularly with regards to coal ash remediation recovery in North Carolina. *Id. at* 59. He stated that the Public Staff's sharing recommendation undercuts both the quantitative and qualitative factors that are positives in the credit rating agencies' assessment of DEP's ratings. The equitable 50/50 sharing proposal, in his opinion, is inconsistent with the core regulatory principle that prudently incurred costs should be allowed for recovery in customer rates. He testified that principle is fundamental to the regulatory compact that undergirds investor willingness to provide needed funding to public utilities, in exchange for a fair return or investment. Based upon his background, he believes that a stark movement away from traditional ratemaking principals, which would also be a clear break away from past Commission precedent, would shake the perception of investors and increase the costs of both equity and debt capital, an impact that ultimately lands at the doorstep of the customer. Accordingly, he recommended that the Company should seek to achieve excellent operating performance going forward and that the Commission should sustain the ongoing constructive regulatory environment, which together should maintain the Company's credit ratings no lower than their current levels within the "A" category. *Id. at* 74-75.

Discussion and Conclusions

The Commission notes that the parties submitted a considerable amount of testimony explaining credit metrics, quality, and ratings. The Company, in particular, shared its views on the potential impact of the Commission's decisions on several issues in this proceeding regarding possible future credit ratings changes and investor perceptions. The Commission found such testimony to be informative and appreciates the efforts of the parties in this regard.

The Commission recognizes and acknowledges that its decisions on important issues in general rate cases are part of the regulatory climate of a public utility operating within North Carolina and are critically reviewed by credit rating agencies. So too are the statutory framework and appellate court decisions. Ultimately, utility management is responsible for managing credit metrics and ratings and investor perceptions. It is they who have levers, such as timing and selection of future capital project spending, issuances of securities and dividend policy, managing daily operations efficiently, and even the provision of a convincing evidentiary record when prudency issues are raised in a proceeding such as this one.

North Carolina General Statutes Section 62-133 sets forth the factors to be considered by the Commission in setting rates for public utilities, stating:

> In fixing rates for any public utility subject to the provisions of this Chapter, . . . the Commission shall fix such rates as shall be fair to both the public utilities and to the consumer.

N.C.G.S. § 62-133(a). The statute further provides that "[t]he Commission shall consider all other material facts of record that will enable it to determine what are reasonable and just rates." N.C.G.S. § 62-133(d).

The statute does not require that the Commission consider the utility's credit ratings or stock prices when fixing rates, a fact that was conceded by DEP witnesses. However, the Commission must set rates that are reasonable and fair to both its customers and existing investors and should allow the utility to compete in the capital markets on reasonable terms.

The Commission has decided the issues in this proceeding based upon the requirements of N.C.G.S. § 62-133. The Commission has given the evidence on credit metrics due consideration. The rates fixed by this Order are supported by the greater weight of the evidence, are fair to both the public utilities and customers, produce just and reasonable rates, and should allow the utility, through prudent management, to access the capital markets on reasonable terms. Indeed, as to the last point the Commission views the ROE and capital structure approved herein to be investor and credit supportive.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 33

Cost of Service Adjustments

The evidence supporting this finding of fact is found in the verified Application and Form E-1; the Public Staff First and Second Partial Stipulations; the testimony and exhibits of DEP witnesses Smith, Metzler, Angers, Hatcher, Henderson, and Pirro, and Public Staff witnesses Dorgan, Metz, Saillor, and Maness; and the entire record in this proceeding.

Summary of the Evidence

As previously discussed, DEP and the Public Staff reached partial settlements with respect to some of the revenue requirement issues presented by the Company's Application, including those arising from the supplemental and rebuttal testimonies and exhibits. Section III of the First Partial Stipulation outlines a number of accounting adjustments to which DEP and the Public Staff have agreed, as does Section III.J through III.L of the Second Partial Stipulation. The revenue requirement effects of the agreed-upon issues are set out in detail in Smith Partial Settlement Ex. 3, Smith Second Settlement Ex. 3, Maness Stipulation Ex. 1, Schedule 1, and Maness Second Stipulation Ex. 1, Schedule 1 (the Partial Stipulation Revenue Requirement Exhibits). The accounting adjustments that are not specifically addressed in other findings and conclusions are discussed in more detail below.

Executive Compensation and Incentive Compensation

In its Application the Company removed 50% of the compensation of the five Duke Energy executives with the highest level of compensation allocated to DEP in the test period. Witness Smith explained that while the Company believes these costs are reasonable, prudent, and appropriate to recover from customers, DEP has for purposes of this case made an adjustment to this item. Tr. vol. 13, 140.

Public Staff witness Dorgan recommended an additional adjustment to remove 50% of the benefits associated with these top five Duke Energy executives. Tr. vol. 15, 741. He contended that this adjustment is consistent with the positions taken by the Public Staff and approved by the Commission in past general rate cases involving investor-owned electric utilities serving North Carolina retail customers and that Public Staff believes that it is appropriate and reasonable for the shareholders of the larger electric utilities to bear some of the cost of compensating those individuals who are most closely linked to furthering shareholder interests. *Id*. at 742. Witness Dorgan also recommended disallowance of incentive compensation related to earnings per share (EPS) and total shareholder return (TSR). *Id.* at 744-45. He asserted that incentive compensation tied to EPS and TSR metrics should be excluded because it provides a direct benefit to shareholders only, rather than to customers. *Id.*

On rebuttal Company witness Metzler testified that the Public Staff's proposed adjustments are inappropriate and should be rejected by the Commission for a number of reasons. Tr. vol. 11, 106, 113-14. Witness Metzler also pointed out that no witness challenged the reasonableness of the level of compensation expenses reflected in the ratemaking test period for the Company. *Id.*

As part of the First Partial Stipulation "[t]he Company accept[ed] the Public Staff's proposed adjustment to executive compensation to remove 50 percent of the benefits associated with the five Duke Energy executives with the highest amounts of compensation, in addition to the 50 percent of their compensation removed in the Company's initial Application." First Partial Stipulation, § III.7. DEP also agreed to accept the Public Staff's adjustment with a modification to limit the incentives removed. This agreement is reflected in Section III.10 of the First Partial Stipulation, which provides that the Company's employee incentives should be adjusted to remove incentive pay related to EPS and TSR for the top levels of Company leadership.

Aviation Expenses

In its initial filing the Company removed 50% of the corporate aviation costs to account for flights that may not be related to provision of electric service. Tr. vol. 13, 144.

The Public Staff made a further adjustment after investigating the aviation expenses charged to DEP during the test year. Tr. vol. 15, 745. Public Staff witness Dorgan contended that based on his review of the flight logs, some of the flights appeared to be unrelated to the provision of utility services. *Id.* at 745-46. He also removed the DEP allocated portion of commercial international flights due to the Public Staff's determination that those flights were unrelated to the provision of utility service. *Id.* at 746.

On rebuttal Company witness Smith explained that all of the costs of the corporate aircraft have been allocated in accordance with the Company's cost allocation manual and that the Company's proposal to remove 50% of the costs is consistent with the Commission's order in Sub 1142. Tr. vol. 13, 190. She also pointed out that the Public Staff's recommendation would result in recovery of only 10% of corporate aviation costs. *Id.*

As part of the First Partial Stipulation the Company agreed to an adjustment that removes aviation expenses associated with international flights, in addition to the 50% of the Company's corporate aviation O&M expense removed in the Company's initial Application. First Partial Stipulation, § III.9.

Sponsorships and Donations

Public Staff witness Dorgan adjusted the Company's O&M Expenses to remove amounts paid to the chambers of commerce, and other donations, reasoning that they should be disallowed because they do not represent actual costs of providing electric service. Tr. vol. 15, 752.

In rebuttal Company witness Angers testified that Chambers of Commerce promote business and economic development, which in turn helps to retain and attract customers to DEP's service territory. Tr. vol. 11, 208. She explained that funds paid to Chambers of Commerce that are not specified as a donation or lobbying on the Chamber invoice are supporting business or economic development and are considered to be properly charged as a utility operating expense that should be included in the Company's cost of providing electric service to customers. *Id*.

As part of the First Partial Stipulation the Company agreed to accept the Public Staff's position on sponsorships and donations expense, which removed certain expenses related to the chambers of commerce and donations. First Partial Stipulation, § III.11.

Outside Services

The Public Staff reviewed costs for outside services associated with expenses that were indirectly charged to DEP by DEBS as well as those incurred by DEP directly and found certain expenses related to legal and non-legal invoices, which the Public Staff contended should not be charged to ratepayers. Tr. vol. 15, 746.

In rebuttal DEP witness Smith partially agreed with the items identified by the Public Staff related to certain outside services. Tr. vol. 13, 186. She agreed that certain outside services should be excluded; however, the Company maintains those costs have already been removed from the revenue requirement as mischarges due to human error. *Id*. at 186-87. She explained in her supplemental direct testimony that the Company proactively removed $0.2 million of system electric operating expenses from allocation to North Carolina retail electric expenses to cover any mischarges identified during the course of the rate case proceeding. *Id.* at 187. As such, the Company believes no additional adjustment to the proposed revenue increase is required for these costs. In addition, she stated that the Company disagrees with the Public Staff's removal of outside services charges of $42,000 for missing invoices explaining that the support for those charges, including invoices, was provided in response to Public Staff Data Request 105. She testified that it is the Company's understanding that the Public Staff agrees that this adjustment was an error. *Id.* She further testified that the Company also disagrees with the description on Line 1 of Dorgan Exhibit and Supplemental Exhibit 1 Schedule 3-1(k), "Remove items related to coal ash litigation." *Id.* Witness Smith explained that the costs that comprise this line item do not include items related to coal ash litigation.

As part of the First Partial Stipulation DEP and the Public Staff agreed that certain outside services expenses should be excluded. First Partial Stipulation, § III.11.

Rate Case Expenses

In its Application the Company requested to amortize the incremental rate case costs incurred for this docket over a five-year period. Tr. vol. 13, 144.

The Public Staff adjusted rate case expense to remove the unamortized portion of rate case expense in rate base, reasoning that the amortization of rate case expense should reflect a normalization of the costs associated with the filing of a rate case, based on a historical average of the number of years between rate case filings. Tr. vol. 15, 751-52. Public Staff witness Dorgan testified that the Public Staff takes the position that rate case expense does not rise to the level of being extraordinary in nature, and, therefore, does not require rate base treatment. *Id*.

In rebuttal witness Smith testified that the Company opposed the Public Staff's adjustment arguing that if the Public Staff had used the historical average costs and number of years between rate case filings since 2013, the amortization amount would have been $1.1 million, which is higher than the Company's proposed amortization amount. Tr. vol. 13, 191. Because the costs are known and measurable, the Company argues that inclusion of the costs in rate base is appropriate and that rate case expenses are incremental costs that have been incurred and funded by investors prior to new rates becoming effective. *Id*.

As part of the First Partial Stipulation DEP and the Public Staff agreed to amortize the rate case expenses over a five-year period but that the unamortized balance will not be included in rate base. First Partial Stipulation, § III.8.

Severance Costs

The Company made an adjustment to remove atypical severance and retention costs included in the test period and also requested to establish a regulatory asset to defer the North Carolina retail amount of $34.9 million of severance costs beginning when rates go in effect, to be amortized over a three-year period. Tr. vol. 15, 752; Application at 16.

Public Staff witness Dorgan adjusted the severance costs to reflect a normalized level over a five-year period, consistent with how the Public Staff has treated severance program costs in other utility rate cases. *Id.* at 752-53.

In rebuttal the Company opposed the Public Staff's adjustment arguing that the adjustment only changed the proposed amortization period and did not calculate a normalized five-year level of severance expense, which would have been greater than the Company's proposed amortization amount. Tr. vol. 13, 192-93.

As part of the First Partial Stipulation DEP and the Public Staff agreed that the severance expenses should be amortized over a three-year period but that the unamortized balance will not be included in rate base. First Partial Stipulation, § III.12.

Lobbying Expenses

Public Staff witness Dorgan noted that the Company assigned some lobbying expenses from the test year to below-the-line accounts, and therefore those costs were not included in the cost of service. Tr. vol. 15, 746. He further adjusted O&M expenses to remove what he characterized as additional lobbying costs, including O&M expenses that he believed were associated with stakeholder engagement, state government affairs, and federal affairs that were recorded above the line. *Id*. at 746-47.

In rebuttal DEP witness Angers explained why the Company opposed this adjustment and disagreed with witness Dorgan's characterization of these expenses. Tr. vol. 11, 201-02. Witness Angers testified that the Company's lobbying expenses are below-the-line, and thus not included in rates. Witness Angers further testified that the amounts the Company has booked above the line align with an independent study performed by KPMG. *Id.* at 202-05.

Witness Angers also testified that it appeared that the Public Staff also removed a percentage of above-the-line expenses related to dues paid to Edison Electric Institute (EEI). *Id.* at 205. Witness Dorgan did not address this adjustment in his testimony, but the Company was able to confirm the adjustment through discovery. *Id.* at 205-06. Witness Angers explained that the Company already books any costs for EEI that are related to lobbying, political activities, or contributions to a charitable foundation, below the line. She further stated that EEI provides a Schedule of Expenses that details EEI's budgeted spend for lobbying and the Company uses that schedule to record the portion of the payment related to lobbying below-the-line. Thus, the Company believes the Public Staff made this adjustment in error. *Id*. However, if the adjustment was not a mistake, witness Angers testified that the Public Staff offered no explanation in testimony to exclude additional amounts over and above-those the Company has already recorded below-the-line. *Id.* The Public Staff acknowledged that the adjustment related to EEI dues was made in error, and the Company accepted the Public Staff adjustment to lobbying expenses, as adjusted and corrected in Smith Partial Settlement Exhibit 3.

As part of the First Partial Stipulation the Company agreed to accept the Public Staff's recommended adjustments to remove certain expenses, as adjusted and corrected, in Smith Partial Settlement Exhibit 3. First Partial Stipulation, § III.13.

Board of Director Expenses

Witness Dorgan made an adjustment to remove 50% of the expenses associated with the Board of Directors of Duke Energy that have been allocated to DEP. Tr. vol. 15, 743. He argued similarly to the adjustment the Public Staff made related to executive compensation, in that the Board of Directors has a fiduciary duty to protect the interests of shareholders, which may differ from the interests of ratepayers. *Id*. Accordingly, the Public Staff believed it was appropriate for the shareholders of the larger electric utilities to bear a reasonable share of the costs of compensating the Board of Directors, as well as the cost of insurance for these individuals.

Witness Metzler explained that the Company is required to have a Board of Directors and that the costs of being an investor-owned utility, including Board costs, are in fact costs of service. Tr. vol. 11, 116. She argued that it is not fair or reasonable to penalize the Company for being an investor-owned utility with attendant requirements to that corporate structure. *Id.*

As part of the First Partial Stipulation the Company agreed to accept the Public Staff's recommended adjustments to the Board of Directors' expenses. First Partial Stipulation, § III.13.

W. Asheville Vanderbilt 115kV Project

The Company recorded the Vanderbilt – W. Asheville 115kV transmission line project in the cost of service as a distribution project. Tr. vol. 15, 735. Public Staff witness Metz explained that the project involved reconductoring approximately two miles of the existing Vanderbilt to West Asheville 115 kV transmission line to accommodate power flows associated with generation additions in the Asheville area. *Id*. at 851. During the course of his review witness Metz discovered the Company had inadvertently booked this project to distribution plant rather than transmission plant; therefore, he believed the Company should reclassify and reallocate the costs accordingly. *Id.* Public Staff witness Dorgan thus made an adjustment to reflect a change in the allocation percentage to North Carolina retail to reflect that this project should have been recorded as transmission plant and not distribution plant.

In rebuttal DEP witness Smith testified that the Company opposes this adjustment because the Company had already made an adjustment in post-test year additions for this project in Smith Supplemental Exhibit 1. Tr. vol. 13, 194.

As part of the First Partial Stipulation the Company and Public Staff agreed to the adjustment to the W. Asheville Vanderbilt 115 kV project as reflected in Maness Stipulation Exhibit 1 and Smith Partial Settlement Exhibit 1 (subject to then unsettled jurisdictional and class allocation factor methodology differences). First Partial Stipulation, § III.14. The First Partial Stipulation also provided that the Company appropriately classified the line as transmission in its supplemental filing.

Credit Card Fees

In its Application DEP requested approval of a fee-free payment program for credit, debit, and ACH payment methods used by the Company's residential customers to pay their electric bills. Currently, customers are required to pay a $1.50 convenience fee, collected by a third-party vendor, for payments made by a credit card. Tr. vol. 11, 863. To offer this program, the Company proposes to pay these costs on behalf of its residential customers and recover these costs as part of its cost of service. *Id*. at 866. Company witness Smith described the Company's proposal to adjust its O&M expense for credit card fee expenses and, in her supplemental testimony, made an adjustment to reflect actual numbers of credit card transactions through February 2020. Tr. vol. 13, 146, 175.

Company witness Hatcher also testified to the value and need for the customer-driven program. Tr. vol. 11, 863-66. He explained that the requirement to pay a convenience fee when making a payment is one of the largest frustrations the Company's residential customers experience. *Id.* at 862. He stated that the Company's Customer Service department routinely receives inquiries about no-cost electronic payment options as evidenced by the Company's monthly residential transaction surveys. *Id.* at 864-65. According to witness Hatcher, customers have grown accustomed to paying for other products and services with a credit card or debit card without a separate, additional fee. *Id.* at 865. As such, many utility companies are now offering fee-free payment programs for their residential customers for all methods of payment. *Id*. at 863. Accordingly, witness Hatcher believes DEP residential customers should similarly benefit. *Id.* at 863. Duke Energy has seen 14% average year-over-year growth in credit/debit transactions over the past several years, and with this change the Company expects the growth rate to double – to 28% more transactions in 2019 than in 2018. *Id.* at 863-64.

While no party contested the value or benefits of the fee-free credit card program for residential customers, Public Staff witness Dorgan noted that the Company did not calculate any impacts to late payments or uncollectibles associated with the request to include credit card fees and has not removed the expenses related to the forms of payment that were utilized in the 2018 cost of service. Tr. vol. 15, 748. Therefore, the Public Staff made an adjustment to remove the O&M expenses included in the cost of service for 2018 associated with the increase in credit card transactions from the 2018 to 2019 period, to avoid double-counting costs associated with the same payments. *Id.*

In rebuttal witness Smith testified that the Company partially agreed with the Public Staff's adjustment and accepted the concept of the Public Staff's adjustment to remove O&M expense associated with the increase in fee-free program transactions from 2018 to 2019. Tr. vol. 13, 186. However, witness Smith testified that the Company has updated the calculation to reflect avoided transaction costs related to payment by check as reflected in Smith Rebuttal Ex. 1. *Id*.

As part of the First Partial Stipulation the Public Staff agreed to the Company's rebuttal position on credit card fees. First Partial Stipulation, § III.15.

End of Life Nuclear Materials & Supplies

Public Staff witness Metz testified that he reviewed the Company's Materials & Supplies (M&S) inventory. Based on that review, he recommended disallowance of $8.9 million in repair hold (RH) and quality assurance hold (QH) costs associated with inventory that has been in a hold status for four years or greater. Witness Metz stated that if inventory and its associated cost cannot be used for extended time periods, those parts (inventory) are unavailable for use, and ratepayers should not be burdened with those costs. Tr. vol. 15, 841-44. Witness Metz also proposed a positive salvage value of 10% be assigned to the M&S inventory, as opposed to the 0% value proposed by DEP. *Id.* at 847-49. Public Staff witness Dorgan made a corresponding adjustment to reflect the recommendation to remove certain items from inventory, as well as the application of a 10% salvage value to end-of-life (EOL) inventory. *Id.* at 748.

In rebuttal Company witness Henderson testified that DEP did not agree with the proposed adjustment regarding RH and QH M&S inventory. Witness Henderson explained that it is appropriate to include RH and QH items that are four or more years old in nuclear M&S inventory because such items ultimately benefit customers by ensuring adequate spare parts and material are available to support the safe and efficient operation of the plants. Tr. vol. 11, 146-47. Witness Henderson explained further that the Company balances priority and cost in order to maximize safety and reliable operation. *Id.* at 148. Witness Henderson described the Company's work to comply with the Commission's directive in the Sub 1142 Order to conform DEP's practices and procedures for managing nuclear and non-nuclear M&S to DEC's current practices and procedures to ensure that proper levels of inventory are maintained. *Id.* at 150. Regarding witness Metz's recommendation regarding EOL nuclear reserve, witness Henderson testified that, while DEP generally agrees that there will be some small amount of salvage value for nuclear M&S inventory at its end of life, this value will be offset because the Company had not applied inflation rates to the inventory values presented. Thus, DEP believed that current inventory value is a reasonable approximate of EOL value less any salvage amounts. *Id*. at 151.

As part of the First Partial Stipulation the Company accepted the Public Staff's adjustment to end-of-life nuclear M&S reserve expense, reduced as described in the direct testimony of Public Staff witness Metz. First Partial Stipulation, § III.16. Company witness Smith and Public Staff witness Maness supported this provision in their settlement supporting testimony. Tr. vol. 13, 231; tr. vol. 16, 29.

CertainTEED Payment Obligations

In the Application the Company included a conditional request for recovery of payment obligations related to a settlement agreement with CertainTEED Gypsum NC, Inc. (CertainTEED). Tr. vol. 13, 149. Recovery of these same expenses were also at issue in the Company's fuel and fuel-related charge adjustment proceeding in Docket No. E-2, Sub 1204 (Sub 1204), pending a determination of whether the costs are considered fuel costs under North Carolina law, such that they are recoverable through the fuel clause. The Company's Pro forma Adjustment No. 33 "Adjust for CertainTEED payment obligation" thus served as a placeholder in the event the Commission determined that the CertainTEED expenses were not eligible for recovery through the fuel clause. *Id*.

On November 25, 2019, the Commission issued its Order Approving Interim Fuel Clause Adjustment, Requiring Further Testimony, and Scheduling Hearing in Sub 1204, finding that the Company's payments to CertainTEED could be recovered as fuel-related costs pursuant to N.C.G.S. § 62-133.2(a1)(9) in the event that the Company's decisions and actions in connection with the settlement agreement were found to be reasonable and prudent. Tr. vol. 13, 176. Accordingly, on December 5, 2019, the Company filed a Letter Regarding Removal of CertainTEED Costs, indicating to the Commission its intent to remove the CertainTEED costs from its base rate request through its supplemental filing, which it subsequently made on March 13, 2020.

The Public Staff requested that the Commission remove the CertainTEED payment obligation from the Company's rate base but later agreed to withdraw this recommended adjustment because the Company had already removed the expense from this proceeding in its supplemental filing. Tr. vol. 15, 751; First Partial Stipulation, § III.19. The Public Staff and the Company therefore agreed that the CertainTEED Payment Obligation was appropriately removed from this proceeding.

May 2020 Updates

On July 2, 2020, the Company filed second supplemental direct testimony and exhibits updating certain material pro forma adjustments through May 31, 2020 (May 2020 Updates). The Company updated revenue requirements through May 2020 for the following pro forma adjustments: customer growth; post-test year additions to plant in service; accumulated depreciation; depreciation expense; property taxes; O&M non-labor expenses; O&M labor expenses; merger related costs; interest synchronization; cash working capital; and an adjustment to update and remove storm costs for securitization. Tr. vol. 13, 240-42.

Though the May 2020 Updates were initially opposed by the Public Staff, DEP and the Public Staff reached agreement regarding the May 2020 Updates in the Second Partial Stipulation, agreeing to include the adjustments, pending and subject to the Public Staff's audit of the updates. Second Partial Stipulation, §§ III.J., IV.A. DEP and the Public Staff also agreed to include updates for benefits and executive compensation. Second Partial Stipulation, § III.J. Finally, DEP and the Public Staff agreed to limit the updates on revenues to 75% of the difference between the May 2020 Updates and the Company's February 2020 update to recognize the uncertainty regarding the effects of COVID-19, with the 75% limitation applicable only if the net effect of the updates on revenues is a revenue requirement increase. *Id.*

After completing the aforementioned audit, on September 16, 2020, Public Staff witness Maness filed second supplemental and settlement testimony and exhibits updating and revising the Public Staff's calculation of its recommended revenue requirement, including the impacts of the Second Partial Stipulation and the accompanying review of the Company's May 2020 Updates. The Public Staff reviewed the Company's proposed updates to net plant, depreciation expense and accumulated depreciation, new depreciation rates, and revenues and related expenses (weather, and customer growth and usage). The Public Staff recommended certain adjustments to these items, and also recommended an adjustment to update certain employee benefits, the Asheville production displacement adjustment, O&M non-labor expense (inflation), and cash working capital, which are reflected in Maness Second Stipulation Ex. 1. Tr. vol. 16, 43-44. The adjustments to the revenue requirement for those items previously settled between the Company and the Public Staff (benefits, weather, customer growth and usage, Asheville production displacement, and inflation) totaled ($318,000), exclusive of the impact on cash working capital.

Lead-Lag Study

The Company submitted a new Lead-Lag Study as Angers Exhibit 3. DEP subsequently revised Angers Exhibit 3 as part of the supplemental testimony of witness Angers. In her direct testimony, Public Staff witness Dorgan proposed adjustments to cash working capital based on the Public Staff's review of the Lead-Lag Study. Witness Angers testified that the Company agreed with the Public Staff's adjustments to cash working capital and noted that the adjustments are consistent with the changes described in the supplemental testimony that is included in the revised Lead-Lag Study.

Weather Normalization, Customer Growth and Usage

DEP witness Pirro testified that he provided the retail sales and number of customers to DEP witness Smith for use in calculating the pro forma adjustment to growth in customers. Tr. vol. 11, 1082. He explained that to arrive at the appropriate number of customers served and the attendant annualized sales levels at the end of the test period, the Company used a combination of regression analysis and a customer-by-customer approach. *Id.* at 1083-84. In his supplemental testimony, witness Pirro testified that the Company had proactively modified its adjustments to annual revenues for customer growth, change in usage, and weather normalization based on Public Staff witness Saillor's recommended modifications in the DEC Rate Case in Docket No. E-7, Sub 1214, which the Company agreed with in principle. *Id*. at 1116-17.

As to customer growth and change in usage, those modifications included:

- Modifying DEP's customer-by-customer approach for openings in the test period by determining average monthly usage through taking the average of the 12 months of billing data following initial month of service;
- Modifying DEP's customer-by-customer approach for openings in the extended period (through February 29, 2020) by removing the initial month of service from the average usage calculation;
- Removing the Basic Customer Charge (BCC) revenues from the change in usage calculations;
- The removal of the change in usage revenue adjustment for the lighting rate class; and
- The inclusion of a change in usage adjustment for the general and industrial rate classes.

Regarding weather normalization, those modifications included: the removal of BCC revenues from the calculations of average customer class rates; and summing of the monthly NC retail kWh weather adjustments within the test period for each customer class in place of multiplying the test period system retail kWh weather adjustment times the annual NC retail-to-system sales ratio. *Id.* at 1117.

Public Staff witness Saillor testified similarly. Tr. vol. 15, 701-03. He also proposed two modifications to the end of test period methodology proposed by DEP: (1) summing the 12 months of billing data following the initial month of service and dividing by 12; and (2) replacing actual sales with weather-normalized sales in the adjustments for the SGS rate class. *Id.* at 708. He also explained his proposed modifications to the customer growth and change in usage adjustments and testified that the Company agrees with each modification except for the change to weather-normalized sales for the SGS rate classes, which was not addressed in witness Pirro's supplemental direct testimony. *Id*. at 709-10.

In rebuttal witness Pirro testified that the Company agreed with the formulaic changes suggested by witness Saillor. In addition, the Company inadvertently did not address witness Saillor's calculation methodology to weather normalize sales for the SGS rate class, with which the Company also agreed. Tr. vol. 11, 1125-26. However, the Company disagreed with witness Saillor's use of customer growth projections through February 2020 because of the significant reduction in its load and associated revenues experienced during the COVID-19 emergency, some of which, the Company believes, could become permanent. *Id.* at 1126. Thus, the Company asserted that reflecting these changes closer in time to the hearing would result in a more accurate depiction of the Company's load forecast. Witness Pirro also testified that there appeared to be a spreadsheet issue with the change in number of bills displayed in witness Dorgan's Supplemental Exhibit 1, Schedule 3-1(b) compared to the change in number of bills displayed in Saillor Supplemental Ex. 3. *Id*. at 1127. He testified that he understood that the Public Staff agreed that the number of bills displayed on Line 15 in Dorgan Supplemental Ex. 1, Schedule 3-1(b) should be 473,731, consistent with Saillor Supplemental Ex. 3.

In his second supplemental direct testimony, witness Pirro testified that the Company updated its customer growth adjustment through May 31, 2020, to incorporate certain known and measurable changes. Tr. vol. 11, 1143. He explained that the updated customer growth adjustment reflects a significant reduction in the Company's load and associated revenues as a result of many commercial and industrial customers as well as schools and colleges scaling back operations, as well as an increase in residential usage, during the COVID-19 pandemic. *Id.* at 1144. Witness Pirro's updated customer growth adjustment reflects the reduction in nonresidential load and increase in residential usage through May 31, 2020.

As noted above, the Second Partial Stipulation addressed the consideration of the May 2020 Updates, with the parties agreeing to include the adjustments, pending and subject to the Public Staff's audit of the updates, and also subject to a limit of the updates on revenues to 75% of the difference between the May 2020 Updates and the Company's February 2020 update to recognize the uncertainty regarding the effects of COVID-19 if the net effect of the updates on revenues is a revenue requirement increase. Witness

Pirro filed Pirro Second Settlement Ex. 4 to reflect the revised revenue requirement resulting from the Second Partial Stipulation and the Company's position on unsettled items.

Non-Labor O&M

The Company adjusted annual non-labor, non-fuel O&M costs, to reflect the increase in costs during the test year that occurred due to the effect of inflation as of December 31, 2018. Tr. vol. 15, 730. Public Staff witness Dorgan adjusted the Company's inflation adjustment to reflect the inflation factor through December, 31, 2019, and modified the Company's inflation adjustment to reflect the Public Staff's adjustment to include variable O&M expenses for changes in customer growth and the removal of aviation expenses, Board of Directors expenses, outside services expenses, uncollectibles, sponsorships and donations, and advertising. *Id.* at 740-41. In rebuttal Company witness Smith did not oppose the adjustment. Subsequently, in the May 2020 Updates, the Public Staff adjusted the amount of non-labor O&M expense included in the determination of the base to which the inflation rate is applied to include the Public Staff's recommended adjustment in non-fuel variable O&M expenses due to customer growth. The Company noted that it agreed with this adjustment. Tr. vol. 16, 49. The specific updated Public Staff adjustments discussed in witness Maness's testimony to which the Company agreed are as follows:

Plant in Service and Accumulated Depreciation

Public Staff witness Maness updated net plant for known and actual changes to depreciation expense and non-generation plant retirements recorded between the end of the test year and May 31, 2020. Tr. vol. 16, 46. Witness Maness also included adjustments recommended by Public Staff witness Metz removing costs related to the Company's Project Focal Point. *Id.* The impact of the removal of costs associated with Project Focal Point, which was part of the Public Staff's adjustments to the update of plant, depreciation expense, and accumulated depreciation, are included in the unsettled update to plant and accumulated depreciation as of May 31, 2020, listed on Schedule 1, Line 5 of Maness Second Stipulation Ex. 1. Although the Public Staff and the Company agreed the item should be removed from plant in service and accumulated depreciation, the item remains unsettled until the Commission determines the appropriate depreciation rates, which are included in the calculation of the adjustment. The Company agreed that these adjustments should be included in the calculation of the final revenue requirement determined in the present case.

Updated Revenues

Public Staff witness Maness updated the energy-related non-fuel variable O&M expense per kWh rate and the annual customer-related variable O&M expense per kWh rate to reflect the use of the SCP allocation methodology to calculate expense amounts used in the calculations and corrected a Public Staff formula error in the schedule. Tr. vol. 16, 47. Witness Maness also updated the customer growth and usage amounts per the recommendation of Public Staff witness Saillor. *Id.* at 47-48. The Company agreed with this adjustment.

Benefits

Public Staff witness Maness updated the benefits related to other post-employment benefits, pension, FASB 112, and non-qualified pensions to reflect the updated 2020 actuarial amounts that became available after the initial update period. The Company agreed with this adjustment. *Id.*

Nuclear Decommissioning Trust Fund

Public Staff witness Hinton testified that in this case DEP proposes a total Nuclear Decommissioning Trust Fund (NDTF) expense of approximately $19.6 million, the same level included in Sub 1142. Tr. vol. 15, 334. He explained that the $19.6 million approved decommissioning expense was based on the Company's 2015 Nuclear Decommissioning Studies. *Id*. He further explained that the Company filed a Nuclear Decommissioning Cost and Funding Report in 2015, which the Company made several updates and adjustments in Sub 1142. *Id*. at 336.

Witness Hinton testified that the Public Staff has concerns with the current use of a cost estimate filed in 2015, based on dollars from 2014. *Id*. at 336-37. DEP's Decommissioning Cost Analyses filed on March 12, 2020, in Docket No. E-100, Sub 56, estimated the cost to decommission DEP's four nuclear units as approximately 18% higher than estimated in the 2015 Cost Analyses. *Id*. Thus, the Public Staff recommends basing the decommissioning expense in this rate case on the 2020 Cost Analyses. *Id*. Witness Hinton testified that he found the Company's assumptions for calculating the Decommissioning expense to be reasonable, with the exception of DEP's proposed rates of return for its qualified trust fund (4.56% average projected long-run rate of return for DEP's qualified trust funds), which he testified "are unreasonable and overly conservative." *Id*. at 340. Relying on witness Woolridge's CAPM testimony regarding a reasonable expected rate of return for the Company's cost of equity, witness Hinton testified that he believes a 9.00% to 9.50% expected rate of return for these assets is reasonable. *Id*. He also provided Confidential Ex. 6, which showed the historical annual rates of return on the funds and testified that DEP's long-run rate of return of 4.56% is overly conservative based on his review of past performance after taxes and fees. He noted that the historical rates of return shown in Exhibit 6 reflected three recessionary periods that were followed by periods of positive growth in the value of DEP's qualified funds. *Id*. at 341. In addition, he argued that the Company's pension and decommissioning funds have similar asset allocations and annual earned rates of return but use a different overall rate of return on its overall fund investments. *Id*. at 342. Finally, witness Hinton testified that he considered other sources, such as Dominion Energy North Carolina's (Dominion) current decommissioning funding study that reflects Dominion's projection of its rate of return on its qualified funds filed in Docket No. E-100, Sub 56. Based on these factors and analysis, witness Hinton recommended use of an overall expected 6.00% rate of return for DEP's qualified trust funds and that the Commission reduce the Company's decommissioning expense to $0. *Id*. at 345.

In rebuttal DEP witness Doss provided an overview of the Commission's Guidelines for determining and reporting nuclear decommissioning costs and the process for determining the amount of nuclear decommissioning costs included in the Company's revenue requirement. Tr. vol. 16, 346-53. He explained that when the Company's Application was filed on October 30, 2019, the Company opted to keep the revenue requirement relating to nuclear decommissioning expense the same as the amount approved in the 2018 Rate Case given that a new study was expected by the end of 2019, and the Company would be going through the lengthy process of updating the cost and funding model in 2020, which was not anticipated to be complete prior to the close of this rate case. *Id*. at 354.

In response to Public Staff witness Hinton's recommendation that the Commission update the Company's decommissioning expense outside of the typical process witness Doss explained that the process of developing a cost and funding model is complicated and includes many inputs and assumptions. *Id*. at 356. He testified that "[s]imply put, there is a reason the Commission requires the Company to go through the exercise of developing a cost and funding model and that the Commission allows 210 days from the receipt of costs estimates for the Company to complete the funding report." *Id*. Witness Doss explained "that process is currently underway and should not be allowed to be short-circuited by the Public Staff." *Id*. Regarding witness Hinton's comparison to market returns relating to ROE as a basis for his recommended NDTF return, DEP witness D'Ascendis testified that witness Hinton's recommendation incorrectly assumes there is no distinction between expected returns assumed in NDTF funding assumptions and other managed asset funds such as pension funds and the required returns that are the subject of his and witness Woolridge's testimony. Tr. vol. 11, 577. Witness D'Ascendis explained that the investor-required return on the market is not equivalent to the expected market return estimates used by asset fund managers, and that one cannot be substituted for the other. *Id*. at 578. He explained that investors may use a more conservative required return estimate for asset fund management purposes than the required return that applies to individual equity investments. *Id*. He also explained that asset fund managers are concerned with investing funds at an expected return to meet expected liabilities over a finite period, while individual equity investors decide whether to commit capital to a given security based on the return that they require to be compensated for the risks associated with that security, in perpetuity. *Id*. at 579. Further, witness D'Ascendis testified that the Commission has previously recognized the distinction between expected returns and required returns. *Id*. at 579-80.

As part of the Second Partial Stipulation DEP and the Public Staff agreed to reduce the annual funding for the Company's NDTF by $8.7 million, and further agreed to support this funding amount in DEP's current cost and funding decommissioning Docket No. E-100, Sub 56. To the extent the Commission orders in that docket a different level of funding than the amount the parties agreed to in the Second Partial Stipulation, the parties agreed that the Company will defer the difference in a regulatory asset or liability to be considered in the next rate case. Second Partial Stipulation, § III.K.

Deferred Non-ARO Environmental Costs

Public Staff witness Maness testified that pursuant to the Commission's approval of the 2016 request for deferral filed in Docket No. E-2, Sub 1103, the Company is proposing to defer and amortize certain depreciation and return requirements related to certain capital projects placed into plant in service since the most recent rate proceeding. Tr. vol. 15, 1583. He explained that these projects are not classified by the Company as legal obligations associated with the retirement of coal ash facilities or the generating plants with which those facilities are associated; instead, they are intended to address coal ash issues related to the continuing operation of the applicable generating plants. *Id.* Although they are not part of the legal obligation that gives rise to DEP's coal ash asset retirement obligation (ARO), the Company and Public Staff agree that these costs are eligible for deferral pursuant to the terms of the Sub 1103 deferral accounting request, because they are needed to fulfill the Company's responsibilities under North Carolina's Coal Ash Management Act (CAMA) and the United States Environmental Protection Agency's Coal Combustion Residuals Rule (CCR Rule). *Id*. However, witness Maness testified that although he does not oppose deferral of the capital (return and depreciation) costs of the projects in this case, he does not agree with the five-year period proposed by the Company over which to amortize the deferred costs. He instead recommended an amortization period of ten years, which would lower the revenue requirement and substantially ease the annual impact of the deferral and amortization on the ratepayer, and that the reduction would not directly harm the Company in that the unamortized amount would earn a return through being included in rate base. *Id.* at 1584.

In rebuttal DEP witness Smith testified that the Company does not agree with witness Maness's recommendation to increase the amortization period for non-ARO related deferred capital expenditures. Tr. vol. 13, 209. She explained that the Public Staff has recommended extending amortization periods proposed by the Company when the amortization involves amounts to be collected from customers but recommends shortening the periods when the amortization involves amounts to be refunded to customers. *Id*. She explained that the Company considered annual rate impacts in its recommendation of the five-year amortization and considered the Commission's decision in the 2018 Rate Case in arriving at its proposed amortization period. *Id*.

As part of the Second Partial Stipulation DEP and the Public Staff agreed that amortization of deferred non-ARO environmental costs over an eight-year period is appropriate. Second Partial Stipulation, § III.L.

Asheville Combined Cycle Project

On March 28, 2016, the Commission approved a certificate of public convenience and necessity (CPCN) for the Asheville Combined Cycle (CC) units (Asheville CC Project), finding that its construction was needed to meet the projected growth in the

Company's Western Region and to meet DEP's total system needs. *See* Order Granting Application in Part, with Conditions, and Denying Application in Part, *Application of Duke Energy Progress, LLC, for a Certificate of Public Convenience and Necessity to Construct a 752-MW Natural Gas-Fueled Electric Generation Facility in Buncombe County Near the City of Asheville*, No. E-2, Sub 1089 (N.C.U.C. Mar. 28, 2016); Tr. vol. 11, 982.

At the time the Company filed its Application in this rate case the Asheville Steam Electric Generating Plant was anticipated to be retired in December 2019 with the new Asheville CC Project scheduled to be in service that same month. Company witness Turner testified that the Asheville CC Project comprises two 1x1 CC dual fuel units (power blocks), and that each power block contains a combustion turbine (CT) generator and steam turbine generator and has a capacity of 280 MW. Tr. vol. 11, 981.

As part of the Application the Company requested that the costs associated with the plant (depreciation, property taxes, incremental O&M and return) incurred from the time the facility is placed into service until the time the approved costs are to be reflected in the new rates, be deferred and amortized beginning with the effective date the Commission approves new rates in this proceeding. Application, at 19; Tr. vol. 13, 166. DEP witness Smith testified that without approval of the Company's request to defer the Asheville CC Project costs, the Company would face an earnings degradation of approximately 80 basis points. Tr. vol. 13, 166. She further explained that approval of the Company's accounting order request for the Asheville CC Project would be consistent with prior Commission practice regarding significant new generation plants and would better align costs with revenues. *Id.*

The Company made a pro forma adjustment to include the amortization of the deferred costs related to the Asheville CC Project that includes an annual level of amortization of deferred costs, including a return on investment, over a three-year period. Tr. vol. 15, 736. As part of this adjustment, DEP included a separate pro forma adjustment to include a proxy for the ongoing O&M expenses and M&S inventory for the Asheville CC Project. *Id*. The Company also included a pro forma adjustment to reflect Power Block 1, including the common plant, and a combustion turbine from Power Block 2 in plant additions as of December 31, 2019, which represented 480 MW of the 580 MW (nameplate capacity) Asheville CC facility that were placed in service as of December 31, 2019. *Id.*

In her supplemental testimony Company witness Smith testified that the Company had updated the Asheville CC deferred balance amortization to reflect the estimated deferred costs and associated regulatory asset established for the Asheville CC Project. Tr. vol. 13, 176-77. She explained that at the time of DEP's Application the plant was expected to be in service in late 2019 and, as of February 29, 2020, Units 5, 6, and 7 were placed in service with Unit 8 expected to be in service before the start of the evidentiary hearing, initially scheduled to commence on May 4, 2020. *Id*. at 177.

Public Staff witness Metz testified that three of the four units at DEP's Asheville CC Project had been placed in service and explained that the plant was only partially in service due to unexpected events that occurred during testing at one of the steam turbines, which required repairs and further testing. Tr. vol. 15, 823. Witness Metz encouraged DEP to continue negotiations with the original equipment manufacturer (OEM) to obtain a "no cost" extended warranty on at least the steam turbine and its associated generator that had experienced damage. *Id.* at 824-25. Additionally, he recommended the Commission require the Company to file a letter in this docket notifying the Commission when the Power Block 2 steam turbine was completed and available for full economic dispatch. Tr. vol. 15, 825-26. Witness Metz also proposed an adjustment to the Asheville CC Project to account for the time delay between the Company's request in this case and the time rates will actually go in effect and to establish an estimated amount of expected plant expenses. *Id.* at 849.

Witness Metz revised the Asheville CC Project O&M estimated expense to reflect a revised cost and change in the cost calculation methodology, both applying a weighted average (instead of simple average employed by DEP) of CC expense versus nameplate capacity and removing certain costs he found to be duplicative or incorrectly charged. *Id.* at 850-51. As a result, Public Staff witness Dorgan adjusted the annual O&M expenses utilized by the Company for the Asheville CC Project and testified that it was his understanding that the Company accepted the Public Staff's methodology for calculating a proxy for O&M expenses. *Id.* at 736-37. Further, witness Dorgan recommended that the deferred Asheville CC Project costs for North Carolina retail be recovered through a levelized amortization over a five-year period. *Id.* at 738. Witness Dorgan also explained that the Company made an adjustment to include 480 MW of the Asheville CC Project in service on December 31, 2019 and that, based on the Public Staff's understanding, the remaining 100 MW was placed in service on April 5, 2020 and would be addressed by the Company in a subsequent supplemental testimony filing. *Id*. at 737, 753-54. Finally, witness Dorgan testified that, with the net addition of kWh due to the Asheville CC Project, other DEP resources will operate less frequently or at lower levels of output and thus incur fewer non-fuel variable O&M expenses. *Id.* at 754. As such he reduced non-fuel variable O&M expenses in a displacement adjustment to prevent the inclusion in cost of service of more than the end-of-period level of these types of expenses.

NC WARN witness Powers testified the project cannot be considered used and useful because both phases were not online until April 5, 2020. *Id.* at 886.

In rebuttal and regarding witness Metz's recommendations DEP witness Turner noted that the repairs performed by the OEM restored the steam turbine generator component of Power Block 2 to new condition, and that the existing contract with the OEM provides for a two-year warranty on both power blocks. Tr. vol. 11, 984. Witness Turner stated that DEP's negotiations with the OEM regarding Power Block 2 are ongoing and include representatives from DEP's legal, supply chain, and project management organizations. *Id.* Regarding witness Metz's recommendation for a letter update, she testified that after completion of the repair to the Power Block 2 steam turbine, DEP submitted an update to the Commission in Docket No. E-2, Sub 1089, stating that the Power Block 2 steam turbine generator went into commercial operation on April 5, 2020. Witness Turner noted an exhibit to her rebuttal testimony, believing based on discussion with the Public Staff that DEP had satisfied the Public Staff's recommendation. *Id*. at 984-85.

Regarding the Public Staff's displacement adjustment for the Asheville CC Project, witness Turner testified that the adjustment is not warranted. She explained that the Asheville CC Project represents the addition of two new CC facilities to the DEP fleet that need to be operated and maintained. *Id*. at 983. In addition to meeting the Company's obligations under the Mountain Energy Act, she noted that these units will also serve a growing number of customers in the surrounding area and the associated growth of energy and peak demand requirements. *Id.*

In rebuttal Company witness Smith stated that DEP accepted the Public Staff's methodology for calculating annualized O&M for the Asheville CC Project but opposed the adjustment to use the annuity factor method to calculate amortization expense, removing the deferral and ADIT balances from the rate base, and disagreed with the dollar amount of the adjustment because it needed to be updated to include Unit 8, which went into service on April 5, 2020. *Id.* at 187, 193-94. In addition, she testified that DEP opposed the Public Staff's recommended amortization period of five years for the deferred costs. *Id.* at 194. Finally, she adjusted the deferred balance of the Asheville CC Project that went into service on April 5, 2020. *Id.* at 215.

In his supplemental testimony Public Staff witness Dorgan updated his adjustment to the Asheville CC Project to reflect DEP's actual costs as of February 2020, and incorporated adjustments to the levelization calculation to reflect that Power Block 2 came online on April 5, 2020, and the entire Asheville CC Project can be economically dispatched. Tr. vol. 15, 772.

The First Partial Stipulation settled the contested issues regarded the Project. Section III.17 of the First Partial Stipulation provided that the Asheville CC Project is complete, placed in service, and available for economic dispatch. It also provided that (a) the appropriate amortization period for the deferred expenses for the Asheville CC Project is four years with a levelized return; (b) the Company's non-fuel variable O&M expense related to the Asheville CC Project should be reduced to account for a production displacement adjustment; and (c) the amount of Asheville CC plant in service appropriate to include in rate base and used for the deferral calculation in this proceeding is the amount reflected in the Company's rebuttal testimony – subject to unsettled jurisdictional and class allocation factor methodology differences – and that the Public Staff reserves the right to review any actual reimbursements received from the EPC contractor in a subsequent rate case. Section III.20 provided to include annualized accumulated depreciation for the Asheville CC Project not previously included in supplemental or rebuttal filings.

In her settlement supporting testimony Company witness Smith explained that the Public Staff and DEP agreed to an adjustment to accumulated depreciation reserve related to the Asheville CC Project to correct an error in the Company's rebuttal filing. Tr. vol. 13, 232.

In his supplemental second settlement testimony Public Staff witness Maness stated that he updated the Asheville production displacement calculation as updated by the Company in its May 2020 update to reflect the calculation using the SCP allocation method, as agreed to by the parties in the Second Partial Stipulation. He stated that the Company had based the calculation on the SWPA allocation factors. Tr. vol. 16, 48.

NC WARN witness Powers testified that NC WARN did not support allowing DEP to recover costs related to the construction of its Asheville CC Project. NC WARN argued that the Asheville CC Project was not reasonable and prudent nor the least cost mix of generation. Witness Powers testified that there were several example of the lower-cost regional power supply that could have been contracted as an alternative to an expensive buildout at Asheville. Witness Powers described additional alternatives in her testimony. Tr. vol. 15, 883-84. Witness Powers additionally described how DEP could have utilized battery storage to reduce costs. She testified that Duke Energy has spent approximately $820 million building the Asheville combined cycle power plant – resulting in DEP's request in this rate case to recover approximately $770 million – that could have been avoided by simply allowing existing solar facilities in North Carolina to add battery storage at their own expense in return for reasonable payment for the added value of the storage capacity. *Id.* at 885.

Discussion and Conclusions

Based on the foregoing and the entire record, the Commission concludes that the provisions of the Public Staff Partial Stipulations on cost-of-service adjustments aptly demonstrate the efforts of the stipulating parties to reach compromise on many details of DEP's operating costs. Auditing a public utility's accounting records and formulating a position on the many cost of service items is a labor intensive and tedious job. The Commission appreciates the work of the Public Staff and the stipulating parties for coming together and working out many of these accounting issues. The Commission determines that the cost adjustment provisions are the result of give-and-take negotiations, and therefore the Commission places great weight on the cost adjustment provisions of Public Staff stipulations. As a result, the Commission concludes that the stipulated adjustments discussed herein are just and reasonable, and the portions of the Public Staff First and Second Stipulations on cost-of-service adjustments should be approved.

Turning specifically to NC WARN's challenge to the cost recovery related to the construction of DEP's Asheville CC Project, the Commission notes that no NC WARN witness conducted any independent analysis, using the information available at the time the Company's investment decisions were made, to support any contention that DEP's Asheville CC Project was unreasonable or imprudent. The Commission instead credits the testimony of Company witnesses Turner and Smith, and Public Staff witnesses Metz, Dorgan, and Maness, as summarized above. That evidence supports that the Company made reasonable and prudent investment decisions with the information available at the time. Additionally, the Commission observes that it already addressed the need for this generation when it issued the CPCN for the Project on March 28, 2016. For these reasons, the Commission rejects NC WARN's recommendation to disallow recovery of the expenses associated with DEP's construction of the two 280 MW combined-cycle natural gas plants at the Asheville Combined Cycle Power Plant.

Accordingly, and in light of all the evidence presented, the Commission finds and concludes it to be just and reasonable that the Asheville CC Project is complete, placed in service, and available for economic dispatch; the appropriate amortization period for the deferred expenses for the Asheville CC Project is four years with a levelized return; the Company's non-fuel variable O&M expense related to the Asheville CC Project should be reduced to account for a production displacement adjustment; the amount of Asheville CC plant in service appropriate to include in rate base and used for the deferral calculation in this proceeding is the amount reflected in the Company's rebuttal testimony (as adjusted by Public Staff witness Maness in his supplemental second settlement testimony); the Public Staff reserves the right to review any actual reimbursements received from the EPC contractor in a subsequent rate case; and annualized accumulated depreciation for the Asheville CC Project not previously included in supplemental or rebuttal filings should be included.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 34-39

Deferral of Grid Improvement Plan Capital Costs

The evidence supporting these findings of fact is found in the verified Application and Form E-1; the stipulations entered into between DEP and several parties; the testimony and exhibits of DEP witnesses Smith, Young, and Oliver, Public Staff witnesses David Williamson, Tommy Williamson, Maness, Thomas, and McLawhorn, NCSEA/NCJC et al. witnesses Stephens and Alvarez, CIGFUR witness Phillips, CUCA witness O'Donnell, Harris Teeter witness Bieber, and Vote Solar witnesses Nostrand and Fitch; and the entire record in this proceeding.

Summary of the Evidence

DEP Direct Testimony

DEP witness Kim Smith explained that DEP requests an accounting order that would allow DEP to defer its GIP capital costs starting with costs incurred in January 2020. She referenced witness Oliver's testimony that DEP's GIP costs meet the Commission's test for deferral because they are not simple, regularly occurring, inconsequential investments but rather are major nonroutine investments that produce substantial customer benefits. She asserted that absent deferral, if DEP pursued its proposed GIP spending, the Company would experience a significant adverse earnings impact that would grow to more than 100 basis points by 2022.

DEP witness Steven Young testified that investors are looking for modernized mechanisms that allow more timely recovery of investments. He stated that "now most of our investments are smaller in nature. They go in service quicker." He also stated that the Company must absorb the related depreciation, O&M, and interest expense, and the deferral mechanism helps to address the lag in both cash and in earnings. Consolidated Tr. vol. 3, 49-50.

DEP witness Jay Oliver testified that DEP developed its GIP to respond to these seven "megatrends":

(1) Population and business growth continue in North Carolina and is concentrated in urban and suburban areas.

(2) Distributed energy technology is advancing rapidly; there are new kinds of load and resources impacting the grid.

(3) New technologies offer new capabilities and functions for the grid.

(4) Customer expectations have changed.

(5) There are more environmental commitments at every level of government.

(6) Major weather events are more numerous and more severe.

(7) Physical and cyber threats to the grid are more sophisticated and are increasing.

Witness Oliver's Exhibit 10 provided an overview of DEP's GIP and showed that DEP seeks deferral accounting for the capital costs related to $987.8 million in capital spending on the following GIP programs during 2020 through 2022: (1) Self-Optimizing Grid; (2) Integrated Volt/VAR Control; (3) Transmission Hardening and Resiliency; (4) Targeted Undergrounding; (5) Distribution Transformer Retrofit; (6) Long Duration Interruptions/High Impact Sites; (7) Transmission Transformer Bank Replacement; (8) Oil Breaker Replacements; (9) Enterprise Communications; (10) Distribution Automation; (11) Transmission System Intelligence; (12) Enterprise Applications; (13) Integrated Systems and Operations Planning; (14) Distributed Energy Resource Dispatch Enterprise Tool; (15) Power Electronics for Volt/VAR Control; and (16) Physical and Cyber Security.

Public Staff Testimony

Public Staff witnesses David Williamson and Tommy Williamson (Williamsons) testified that DEP is currently working on thirteen of the GIP programs, that it had spent about $38 million on the programs during the 2018 test year on a system basis, and another $163.8 million in 2019, again on a system basis. In 2020, DEP spent another $36.9 million as of the end of February.

The Public Staff reviewed DEP's proposed GIP in order to identify programs that it believes are unique and extraordinary and hence appropriate to consider for deferral. They sought to identify those programs that would bring the grid up to new standards of operation and reliability. The Public Staff rejected for deferral those programs that are the kinds of activities that DEP engages in or should engage in on a routine and continuous basis. The Williamsons concluded that the following GIP programs are extraordinary: (1) The automation and control portion of the Self-Optimizing Grid; (2) the advanced distribution management system portion of Self-Optimizing Grid; (3) Transmission System Intelligence; (4) the Underground Automation portion of Distribution Automation; and (5) Integrated Systems and Operations Planning. The Public Staff said these initiatives are transformative and would provide significant new capabilities to the grid.

Public Staff witness Michael Maness testified that DEP intends to spend about $186 million on the GIP programs that the Williamsons identified as extraordinary. Witness Maness stated that, absent deferral, the return on equity impact of these programs would average about 14 basis points over the next three years, and under normal circumstances the Public Staff would not recommend deferral of an investment with a basis point impact of such a small nature.[10] He stated that in this case, however, the Public Staff took notice of the Commission's order from DEC's last rate case, which was issued June 22, 2018, in Docket No. E-7, Sub 1146 (2018 DEC Rate Order). Witness Maness asserted that in the 2018 DEC Rate Order the Commission appeared willing to be lenient regarding the magnitude of costs or financial impacts necessary to justify deferral for grid improvement investments. For that reason, he did not object to the Commission allowing deferral of the capital costs of the five programs identified by the Williamsons, so long as the Commission determined that the estimated basis point impact falls within the range of leniency that the Commission is willing to grant. Witness Maness further stated that such a deferral should be considered specific to this case and not be treated as precedent in any future general rate case proceeding or deferral request.

Public Staff witness Thomas reviewed the cost-benefit analyses that DEP provided for some of the GIP programs. While he did not recommend rejection of any of the programs, he did express concern that a majority of the benefits identified in DEP's cost-benefit analyses were estimates of the financial benefits customers would receive by avoiding power outages. He noted that DEP relied on a Lawrence Berkeley National Laboratory report (LBNL Report) to estimate the financial value of these benefits. Witness Thomas testified that 87% of the benefits of DEP's GIP were customer reliability benefits and that where reliability benefits were broken out by customer class about 97% of those benefits would accrue to commercial and industrial customers. Witness Thomas testified that DEP's cost estimates for the GIP programs were of a high-level nature, and that actual costs could vary widely from such estimates. He pointed out other concerns with DEP's cost-benefit analyses but ultimately did not recommend rejection of any of them. He recommended that GIP expenditures be tracked and reported, that DEP perform cost-benefit analyses for additional GIP programs, that it file sensitivity analyses of its cost-benefit analyses that include cost variations, and that it remove or modify benefits in its analyses, including long-term reliability benefits, CO_2 emission savings, avoided capacity planning margin requirements gross-up, and avoided capacity in years when no capacity is needed. He recommended that DEP consider conducting a study to more

[10] On April 23, 2020, witness Maness filed supplemental testimony in which he made slight adjustments to his ROE calculations, which he described as impacting 2021 and 2022 results by one basis point, an amount "that does not affect the recommendation in my initial testimony."

accurately reflect its customers' outage costs. In addition, witness Thomas recommended that DEP revise its analysis for the Transmission Hardening and Resiliency program to assign reliability benefits to customer classes. He stated that DEP should revise the Self-Optimizing Grid cost-benefit analysis to include the effect of momentary outages and the expected reduction in vegetation-related outages from increased vegetation management. Thomas said DEP should consider how GIP investments would impact other costs, such as inventories, and that DEP and the Commission should consider changing the allocation of GIP costs among customer classes.

Witness Thomas recommended that DEP reduce the scope of the DSDR[11]-to-CVR conversion project in order to determine the amount of peak shaving that would be lost by full conversion. He stated that DEP intends to seek relief from its current DSDR peak shaving obligation. He stated further that DEP had not estimated the amount of peak reduction that will be lost by the conversion, "therefore its CBA [cost benefit analysis] does not represent an accurate estimate of the benefits to ratepayers." Witness Thomas stated that "DEP should proceed in a manner that will ensure that the decision to reduce peak shaving capabilities, particularly in the winter, does not cost ratepayers more than anticipated."

Public Staff witness James McLawhorn stated that the benefits derived from some of the GIP transmission and distribution assets are disproportionately related to the way the GIP transmission and distribution plant is allocated. He believes this area of cost allocation deserves further study.

NCJC. et al. Testimony

Witness Stephens reviewed DEP's proposed GIP, including its cost-benefit analyses. He identified deficiencies in some of the analyses and a lack of justification for other GIP programs. He recommended that the Commission reject DEP's GIP and establish a separate proceeding for developing a new GIP plan and budget. He identified eight of DEP's GIP programs that merit approval, with conditions, because they represent standard industry practice, consist of software that is needed to optimize grid assets, operations, or cyber security, are likely to deliver benefits to ratepayers in excess of costs, or are critical to provide stakeholders' value that cannot be otherwise secured. These eight programs are: (1) Integrated Volt/VAR Control; (2) the flood and animal mitigation portions of Transmission Hardening and Restoration; (3) Long Duration Interruptions/High Impact Sites; (4) Foundational software including Enterprise Applications, Integrated Systems and Operations Planning (ISOP), and Distributed Energy Resource Dispatch; (5) Cyber Security (excluding substation physical security); (6) Enterprise Communications (excluding mission critical voice and data network); (7) Power Electronics for Volt/VAR Control; and (8) Automated Distribution Management System.

[11] DSDR stands for distribution system demand response.

Witness Stephens stated that the Self-Optimizing Grid (SOG) program should be approved but at a reduced level to focus on circuits that would experience the greatest benefit. As to the Transmission Hardening and Restoration program, he stated that the entire budget should focus on projects to accommodate more distributed energy resources.

Witness Stephens testified that the Commission should reject the following programs because they are not generally cost-effective: (1) Targeted Undergrounding; (2) Distribution Transformer Retrofits; (3) Transformer Bank Replacements; (4) Oil-filled Breaker Replacements; and (5) Substation Physical Security. Witness Stephens recommended that the Commission require on-going performance measurement for DEP's GIP initiatives as well as cost caps and operating audits.

In addition, witness Stephens recommended that the Commission reject the Mission Critical Voice and Data Network Development Programs because Duke Energy conducted no make-versus-buy evaluation of alternatives to its own $160-million proposal to build proprietary voice and data networks. Similarly, Stephens said DEP provided no cost-benefit analyses for its Distribution Automation and Transmission System Intelligence programs.

Witness Alvarez criticized DEP's reliance on the LBLN Report for estimating outage costs; he said the report is based on old data that is geographically biased and biased toward manufacturing and retail businesses that have the highest outage costs of all commercial and industrial segments. Further, the surveys used to collect outage cost data did not consistently address the availability of back-up generators and uninterruptible power supply systems. Alvarez asserted that DEP over-estimated the GIP's benefits by overstating the number of outages being avoided by the programs, then by overstating the economic benefits of those avoided outages, and finally by using those overstated primary benefits as inputs to the IMPLAN software, which estimated the secondary benefit of the GIP. Further, he contended that DEP did not estimate the detrimental impacts on North Carolina's economy of the significant rate increases that the GIP would generate. He asserted that the GIP would cause a 3.8% rate increase, that residential customers would likely be allocated about 59.2% of the costs, and that they would pay at least $10.44 for every $1 in benefits that they receive. On the other hand, he asserted that Duke Energy's shareholders would likely earn $2.6 billion in return on equity over 30 years, or $1.2 billion in present value terms, from its GIP investments. He testified that DEP's GIP will ultimately cost ratepayers $8.6 billion over 30 years, or $3.4 billion in present value terms. He also asserted that the GIP presents an asymmetrical risk profile, one in which ratepayers take all the risk for benefit delivery and cost overruns, while shareholders earn a rate of return under all scenarios. He recommended that the Commission reject DEP's GIP and its request for deferral accounting and establish a proceeding to develop a transparent, stakeholder-engaged distribution planning and capital budgeting process.

CIGFUR Testimony

Witness Phillips testified that there is no compelling evidence demonstrating that grid improvements warrant a departure from standard ratemaking practices. Further, he asserted that DEP's plan would shift regulatory risk from its investors to customers as well as allow DEP to pursue single-issue ratemaking. He testified that the deferral, if approved, could eliminate DEP's incentive to prudently manage costs between rate cases, and that GIP costs are not volatile or unpredictable. Phillips stated that if the deferral is approved, DEP's allowed ROE should be reduced to reflect the reduced business risk that its investors will face.

CUCA Testimony

Witness O'Donnell testified that DEP's proposed grid expenditures are too expensive and lack customer support. He stated that many of the programs lack cost-benefit analyses to prove that they are beneficial and should therefore be disallowed. He stated that the Commission should only allow recovery of GIP program costs where promised reliability benefits are achieved.

Witness O'Donnell testified that regulated utilities have an incentive to build plant, and that DEP offered no performance guarantees. He asserted that Duke Energy intends to pursue its Power Forward grid initiative, of which GIP is a part, and that this $13 billion 10-year grid modernization effort will cause massive rate increases. He asserted that a typical DEP industrial customer would pay $4.1 million more over 10 years due to DEP's GIP investments.

Harris Teeter Testimony

Witness Bieber recommended that the Commission reject DEP's proposal to defer GIP costs. He stated that deferral is unnecessary and would amount to single-issue ratemaking. Bieber testified that DEP's GIP costs do not appear to be volatile or outside the Company's control, and that they should be considered in the context of general rate cases.

NC WARN Testimony

Witness Powers recommended that the Commission reject DEP's GIP proposal, stating that the stakeholder workshops that DEP hosted were essentially sales presentations. He stated that the high cost of the GIP is such that additional rigorous review is needed to protect ratepayers. He testified that the GIP presumes that there is only one pathway to grid modernization and that other alternatives should be considered. For example, installing battery storage in residences would be a less costly way to improve reliability than the Targeted Undergrounding program that DEP proposed.

Vote Solar Testimony

Witnesses Nostrand and Fitch testified that DEP's GIP does not assess or respond to climate-related risks, and it does not adhere to grid modernization best practices. They recommended that the Commission: (1) direct DEP to assess and manage climate-related risks across its operations and assets; (2) make clear that it will apply this standard to GIP investments; (3) direct DEP to participate in Department of Environmental Quality stakeholder processes around grid modernization, and integrate data, findings and recommendations into its GIP; (4) require DEP to file a report identifying gaps in knowledge that need to be filled through further collaboration; (5) require DEP to develop a GIP through an integrated distribution planning process; and (6) if GIP deferral is allowed, impose performance-based conditions on the recovery of the deferred amounts.

DEP Rebuttal Testimony

Witness Oliver stated that none of the intervenor witnesses dispute the megatrends that are driving the need for the GIP.

As to the Public Staff's assertion that some GIP programs do not meet the definition of grid modernization, Oliver argued that each program within the GIP seeks to bring the current grid up to new standards of operation or reliability. He then used the same matrix and methodology for analyzing GIP programs that the Public Staff had developed, scored the programs higher for some attributes, and concluded that these programs should be added to the Public Staff's list of "extraordinary" programs:

(1) SOG Capacity and Connectivity;

(2) DSDR Conversion to CVR;[12]

(3) Distribution Automation (the Underground System Automation subprogram was already included in the Public Staff's list);

(4) Power Electronics;

(5) Distributed Energy Resource Dispatch Tool; and

(6) Cyber Security

[12] The Commission notes that DEP's GIP is inconsistent as to its proposed treatment of new GIP-driven DSDR-related costs. While the CVR conversion costs are included in the deferral requested in this rate case, DEP apparently plans to recover other DSDR-related GIP costs in the Company's DSM/EE rider. Oliver Exhibit 10 states that next generation cellular and capacity bank control replacements "associated with DSDR assets will not be recovered under GIP but instead will be separately evaluated and recovered under the [DSDR] rider." *See* Oliver Ex. 10, at 51, 90.

Where the Public Staff's list of five "extraordinary" programs totals $186.1 million in capital spending from 2020-2022, Oliver's six programs would add $248 million to that amount, for a total of $434 million. As to the other programs, Oliver stated that the Public Staff's evaluation method is one rational approach but it is not the only way to evaluate programs. Oliver asserted that all of DEP's GIP initiatives meet the definition of grid modernization and all their costs should be eligible for deferral.

The costliest GIP program that the Public Staff disputed is SOG at $302 million in capital over three years. Oliver stated that SOG is an example of a GIP project that addresses all the megatrends, not just reliability. He said that when privately owned roof-top solar becomes widespread, a dynamic, automated, capacity-enabled two-way power flow grid will be essential. During lightly loaded shoulder seasons, SOG would allow excess DER energy to be routed to adjacent neighborhoods for use, maximizing its value and reducing line losses.

Witness Oliver asserted that SOG will allow DEP to defer capacity. He stated further that DEP plans to deploy SOG on circuits where it will have the most benefit. Since that deployment will increase DEP's efficiency when responding to outages, it will benefit all customers. Witness Oliver disagreed with Public Staff witness Thomas' assertion that SOG will result in an increased number of momentary outages.

Witness Oliver responded to witness Thomas' concern that SOG benefits are overstated because DEP failed to consider the reduced number of vegetation-related outages that will occur due to DEP's tree trimming plans. He noted that Thomas stated that he believed that any such impacts would be even less on DEP's system than on DEC's, where the impacts were only two percent. In addition, DEP's cost-benefit analysis for SOG did not include any benefits for improving reliability on major event days. He said that SOG is a "no regrets" investment that provides significant value for customers in multiple ways.

As to the Public Staff's concern that the DSDR-to-CVR conversion will result in lost peaking capacity, witness Oliver stated that DEP agrees with witness Thomas that the amount of peak reduction lost by the conversion will require further analysis. He argued, however, that converting DSDR to CVR now is critical to enable the greater use of distributed energy resources. A delay in the conversion would reduce the grid's ability to respond to the growing penetration of solar generation. Operating in CVR mode will provide increased visibility into the status and condition of substation and field devices to help respond to intermittency. In addition, the conversion will result in greater fuel savings than is currently provided by DSDR.

Witness Oliver responded to witness Alvarez' assertion that Duke Energy's GIP cost-benefit analyses contain $425 million in capital spending that is not included in Duke's three-year capital spending. Oliver stated that it is not accurate to compare the capital budget spending plan in his Exhibit 10 to the costs in DEP's GIP cost-benefit analyses because they serve different purposes. He stated that some of the cost-benefit analyses are for projects or programs that start in the 2020-2022 period but continue into 2023 and beyond.

Oliver stated that the majority of the $1.1 billion in software and communications replacement costs identified by Alvarez are justified under cost-effective guidelines instead of via a cost-benefit analysis. He said that there is no need to evaluate all programs over the same lifecycle.

As to witness Alvarez' assertions that Duke Energy did not consider alternatives for its $160 million in communications network investments, witness Oliver said Duke Energy followed documented enterprise supply chain processes, including requests for information and requests for proposals, to evaluate alternatives. He said that, where appropriate, considering the cost, security, speed to deploy and level of service required, external carriers provide services to Duke Energy's networks. He testified that core data network requirements exceed the current capabilities that third-party cellular providers can provide, given their bandwidth limitations. Oliver stated that for the Land Mobile Radio program, alternative services were considered, and bidders were eliminated because of their inability to meet requirements.

Oliver disagreed with witness Alvarez' assertion that DEP's cost-benefit analyses overstate benefits to C&I customers, calling this assertion misleading. As to Alvarez' critique of DEP's IMPLAN analysis, Oliver stated that the impact of rate increases was outside the scope of that analysis.

Oliver asserted that the cost-benefit analyses included in his direct testimony provide metrics for the programs, such as the amount of O&M savings DEP anticipates, the amount of avoided capital costs DEP anticipates, and the number of outages each program is anticipated to avoid. He said that DEP will track project/program scope, schedule, cost, and benefits as appropriate during implementation.

In response to witnesses who argued that DEP's transformer retrofit, bank replacements, breaker replacements, and transmission line rebuilds were not appropriate grid modernization initiatives, and that they are business-as-usual activities, Oliver stated that the GIP accelerates the pace of these efforts to better position DEP to deal with future requirements.

As to DEP's Targeted Undergrounding program witness Oliver acknowledged that its scope had been scaled back by about 90%. He said the remaining program is highly cost beneficial. He disagreed with witnesses who asserted that Targeted Undergrounding is not standard industry practice and stated that both Dominion Energy in Virginia and Florida Power & Light in Florida have similar programs.

As to DEP's plans to upgrade the security of substations Oliver stated that DEP used a graded approach to physical security at substations not covered by NERC CIP-014, NERC's physical security standard. Oliver stated that most substations will not need security improvements.

In response to critics of Duke's grid modernization stakeholder process Oliver stated that DEP used the feedback received in the workshops to validate the megatrends, conduct additional analyses, drive future workshop discussions, and make significant changes to the portfolio of investments.

He stated that the GIP is a three-year plan, while Power Forward was a ten-year plan, and that the scope of the two plans is dramatically different. He noted that Distribution Hardening and Resiliency and Targeted Undergrounding made up 64% of Power Forward but are only 11% of the three-year GIP and also stated that GIP contains several new programs, specifically the conversion of DSDR to CVR, and the addition of Cyber Security. He stated that Self-Optimizing Grid is generally supported by all stakeholders, made up less than 10% of Power Forward, but is the largest program in the three-year GIP, making up over 31% of the total. Oliver stated further that the GIP begins to prepare the North Carolina grid for growth in privately owned distributed energy resources and electric vehicles, but even if this growth does not occur, the plan still is cost effective. He stated further that there is currently no "Phase 2" of the plan, and that any future plan would be based on collaboration with stakeholders.

Witness Oliver acknowledged that the GIP does not address third-party owned DER accommodation in North Carolina. He stated that while some GIP programs and projects provide ancillary benefits to interconnection issues, those benefits are secondary to the programs' primary purposes.

Witness Oliver recommended that the Commission ignore witness Alvarez' recommendation to reject the GIP and establish a proceeding to develop a transparent, stakeholder-engaged distribution planning and capital budgeting process. Oliver referred to Exhibit 3 of his direct testimony, which lists six negative implications of a business-as-usual response to DEP's identified megatrends:

(1) Increased costs;

(2) Reduced reliability and resiliency;

(3) Reduced ability to manage and integrate distributed energy resources;

(4) Reduced ability to meet customer expectations and commitments;

(5) Reduced economic competitiveness for North Carolina; and

(6) Increased geographic and demographic disparity.

Witness Oliver stated that if the Commission were to reject the Company's deferral request, the work in the GIP would have to be sub-optimized, delayed, diminished in scope and effectiveness, and potentially not done at all.

Similarly, witness Oliver rejected arguments that the GIP should be delayed until an IRP or ISOP process is conducted. He asserted that delay could hinder the ability of ISOP to deliver benefits, and he stated that Duke is already engaging stakeholders to develop the ISOP process.

DEP witness Smith responded to witnesses who expressed concern about the ratemaking aspects of DEP's GIP deferral request. She asserted that cost recovery is a separate and distinct process from deferral of costs. She stated that deferral would allow DEP the opportunity to avoid adverse financial impacts of regulatory lag, but only to the extent the Commission ultimately allows recovery of the deferred costs in a future proceeding. Witness Smith stated that even if DEP were allowed to defer its GIP costs, the Company would still bear the risk of recovering the costs in a future rate proceeding.

Witness Smith clarified that DEP is not requesting deferral of its GIP capital expenditures. Rather, DEP is requesting to defer the traditional revenue requirement amounts associated with the GIP capital expenditures. She stated that when the Company makes capital investments as part of the GIP, the cost to be deferred would be the depreciation and return on investment for the completed plant in service. She stated that if the Company spends $1.2 billion in capital over a three-year period, the deferred cost associated with that amount is not $1.2 billion, but instead is three years of annual depreciation and return on that investment, beginning at the date the assets are completed and in service. She explained further that the deferral would include the financing costs related to the amounts that are unrecovered during the period between the in-service date of the asset and when Company rates are updated to include cost recovery of the assets.

Witness Smith disagreed with those witnesses who asserted that deferral would cause customers to bear the risk of cost overruns or GIP scope shortcomings. She stated that the Commission has full authority to address cost overruns or scope issues during a future general rate case when the deferred costs are presented for recovery, and that DEP bears the full risk of any disallowances that the Commission could choose to impose. During the consolidated evidentiary hearing witness Smith stated that the costs would be deferred over the three-year period, and in DEP's next general rate case all the deferred costs will be reviewed by the intervenors and the Commission. "And the Commission, at that time, will decide" whether the "costs we incurred were reasonable and prudent." She said that the costs witness Oliver has presented are estimates, "and as in any investment that the Company makes where we do a budgeted amount and then we have actuals … people go through and look at why it was different . . . . That analysis is normally done by the intervenors." Consolidated Tr. vol. 6, 106-107.

In summary, witness Smith stated that by hosting its stakeholder process as directed by the Commission in the 2018 DEC Rate Order DEP was able to assure that the GIP programs constitute grid modernization and hence are extraordinary, as opposed to customary spend. She testified further that absent deferral DEP's GIP spending would cause it to experience significant adverse earnings impacts. She stated that the three-year GIP comprises numerous projects that have a short construction period and therefore will be quickly placed into service. "Given the length of time to complete a general rate case, even if the Companies had rate cases every year, the delay in cost recovery from the month that the grid improvement is placed in service to the month that the costs are reflected in the Companies' new base rates could be significant, on average more than a year." Witness Smith testified further that the Commission has demonstrated that "deferral is not a rigid concept but can be flexibly applied to ensure that the Commission fulfills its fundamental mandate to set rates that are just and reasonable and fair to both the Companies and their customers." Consolidated Tr. vol. 6, 88-89.

During the consolidated portion of the hearing, DEC witness Jane McManeus stated that, having "been granted a regulatory deferral as a regulatory asset, . . . I think that's sort of a nod from the Commission to say we understand the costs you're talking about and we don't view them as inappropriate programs or inappropriate electric expenses that one should not ever recover from a customer, assuming that they are reasonable and prudently incurred." When asked, witness Smith said that she agreed with witness McManeus' testimony. Consolidated Tr. vol. 9, 24.

Witness Smith stated further that DEP had spent almost $280 million on GIP from January 2018 through May of 2020. Consolidated Tr. vol. 9, 33. No party disputed these costs.

During the consolidated evidentiary hearing, witness Oliver stated that the Company's capital spending estimates for the GIP programs relied on unit cost estimates that involve a range of cost uncertainty from -20% to +30%. Consolidated Tr. vol. 10, 23.

Public Staff Second Partial Stipulation

In the Second Partial Stipulation the Public Staff agreed to support deferral for the following GIP programs: (1) Self-Optimizing Grid (all programs including capacity, connectivity, segmentation, and automation), (2) conversion of DSDR to CVR, (3) Integrated Systems and Operations Planning, (4) Transmission System Intelligence, (5) Distribution Automation, (6) Power Electronics, (7) DER Dispatch Tool, and (8) Cyber Security. For all other GIP programs, DEP agreed to withdraw its request for deferral accounting.

The Public Staff and DEP agreed that the Second Partial Stipulation constitutes only approval of the decision to incur GIP costs; the Public Staff reserved the right to review actual costs for reasonableness and prudence in the future. DEP and the Public Staff agreed to jointly develop biannual reporting requirements to track GIP expenditures that receive deferral treatment. This will include: (1) tracking costs for each program, including the number of devices installed, types of projects completed, or circuits modified or impacted; (2) reporting on a circuit and substation level; (3) summarizing actual benefits compared to projected benefits; (4) reporting the operational system impacts of Self-Optimizing Grid and Integrated Volt/VAR Control; and (5) providing data and analyses that inform any significant changes to the scope of the Self-Optimizing Grid and

Integrated Volt/VAR Control programs. The first report would cover spending in the last six months of 2020.

DEP agreed to assess the cost effectiveness of GIP projects in an on-going manner and to undertake a cost-benefit analysis for its automated lateral device program.

Further, GIP deferral would be restricted to capital costs (return, property tax, and depreciation) related to plant in service and incremental expenses net of operating benefits, for plant placed in service between June 1, 2020, and December 31, 2022, and a return on the deferred balance. Deferral would cease upon the effective date of any general rate case order in which the associated eligible plant is included in rate base. If no general rate case order recognizing the entirety of eligible plant in rate base is issued by December 31, 2024, DEP would cease deferral of all eligible net costs and carrying costs and consult with the Public Staff regarding the beginning of amortization of the deferred costs for regulatory accounting and ratemaking purposes. Under the Second Partial Stipulation, GIP deferral would not include overhead or administrative and general costs, but the capitalized project costs may include a reasonable allocation of management and supervision costs.

During the consolidated portion of the evidentiary hearing, DEP witness Oliver stated that the Second Partial Stipulation with the Public Staff neither has a spending cap nor includes performance guarantees. Consolidated Tr. vol. 6, 33-34, 68.

Witness Smith stated that the ROE impact for the eight GIP programs in the Second Partial Stipulation was a cumulative impact of 59 basis points in year three if the Commission were to deny the deferral, but DEP nonetheless pursued those programs. Consolidated Tr. vol. 9, 37. Witness Oliver said that the benefits of the programs, as stated in his direct testimony Exhibit 7 cost-benefit analyses, would be tracked under the Second Partial Stipulation. Consolidated Tr. vol. 6, 16. Witness Oliver also stated that DEP will implement GIP regardless of whether the Commission approves the Company's deferral request. However, the deferral would give DEP the ability to implement the GIP programs in a more cost-effective manner. *Id.* at 56.

CIGFUR Stipulation

In the CIGFUR Stipulation CIGFUR agreed to support DEP's GIP deferral request but reserved the right to review and object to the reasonableness of specific project costs in future rate cases. DEP agreed to propose to allocate GIP costs using the minimum system method and voltage differentiated allocation factors for distribution plant.

Commercial Group Stipulation

In the CG Stipulation Commercial Group agreed not to oppose or support DEP's GIP deferral request. DEP agreed that any GIP costs that are allocated to its SGS-TOU customers shall be recovered via SGS-TOU demand charges.

Harris Teeter Stipulation

In the HT Stipulation Harris Teeter agreed to support approval of GIP deferral but is not precluded from taking any position in future cost recovery proceedings regarding the reasonableness of specific GIP costs. DEP agreed that any GIP costs allocated to SGS-TOU customers shall be recovered via SGS-TOU demand charges.

Vote Solar Stipulation

In the Vote Solar Stipulation Vote Solar agreed to support DEP's deferral of costs for the following GIP programs: ISOP, DSDR, SOG, Distribution Automation, Transmission System Intelligence, DER Dispatch Tool, and the 44-kV Line Rebuild[13]. The Vote Solar Stipulation stated that Vote Solar believes that these investments will enable and support the greater use of distributed energy resources. Vote Solar agreed not to oppose deferral of the other GIP programs' costs. Further, "to the extent that DEP enters into an agreement with other intervening parties agreeing to a cost cap," Vote Solar supported such cost containment measures. DEP committed to develop potential pilot GIP customer programs to increase the use of distributed resources prior to submission of its 2022 IRP. If DEP and Vote Solar agree that these programs are cost effective and meet Commission requirements, DEP agreed to file them for approval, and Vote Solar agreed to support such approval. Vote Solar reserved its right to review and object to specific project costs in future rate cases.

NCSEA/NCJC et al. Stipulation

In the NCSEA/NCJC et al. Stipulation NCSEA and NCJC et al. agreed to support DEP's deferral request for: (1) ISOP, (2) DSDR, (3) SOG, (4) Distribution Automation, (5) Transmission System Intelligence, (6) DER Dispatch Tool, and (7) 44-kV Line Rebuild, stating that these programs will enable and support greater use of DER. For all other GIP investments, NCJC et al. did not oppose deferral.

For its part DEP agreed that congestion relief will be a primary criterion in planning and decision-making regarding future transmission and distribution investment, and that DEP will implement the basic elements of ISOP in its 2022 IRP. Following the 2024 IRP, DEP agreed that it will provide hosting capacity analyses for a sample of circuits, contingent on the Commission approving recovery of the costs. In addition, DEP agreed to preview a distributed generation guidance map with the TSRG in third quarter 2020, incorporate input and publish it. Finally, DEP agreed that its 2021 IRP will include details of how DERs and non-wires applications will be examined in ISOP.

[13] Oliver Exhibit 7 details expenditures for GIP upgrades to the DEC 44-kV system but not to the DEP system; it is the Commission's understanding that there are no 44-kV transmission resources on the DEP system.

During the consolidated portion of the evidentiary hearing witnesses Alvarez and Stephens agreed that the programs supported by NCSEA and NCJC et al. would support renewable energy deployment or improve reliability. Consolidated Tr. vol. 8, 97.

DEP Joint Testimony

On August 5, 2020, DEP witnesses Oliver and Smith filed joint testimony and exhibits in response to a July 23, 2020 Order in which the Commission directed DEP to file supplemental GIP economic analyses. The DEP analyses showed the revenue requirement and rate impacts of approving deferral for the smaller group of GIP projects covered in the Second Partial Stipulation between DEP and the Public Staff. Page 1 of GIP Exhibit 3 – Deferral Granted (Settlement) of that testimony showed that, under the Second Partial Stipulation, deferral and a subsequent rate case in 2024 would produce a revenue requirement of $69.9 million in 2024, and a rate increase at that time of 2.8% for residential customers, 2.6% for small general service customers, and 0.4% for large general service customers. This analysis used the ROE and capital structure agreed to in the Second Partial Stipulation.

Witness Oliver testified that if the Commission does not grant deferral accounting, the Company would likely vary its GIP spending from year to year, performing smaller pieces of GIP over a much longer timeframe, which would delay benefits for customers. He stated that the deferral mechanism would give DEP the ability to implement the GIP programs in a much more cost-effective, planned-out way, and to bring the benefits to customers sooner. Further, the deferral would allow DEP to accelerate the historical pace of GIP spending to better position DEP for the future. Consolidated Tr. vol. 6, 45-46.

Witness Oliver testified that in order to perform GIP work at the pace and scope that provides the most benefit to customers, DEP needs new and modern ways to recover costs and avoid the regulatory lag that can harm the Company's financial metrics and, in turn, customers.

Witness Oliver further testified that DEP's GIP programs "are the core of grid modernization," because they provide for two-way power flows, advanced distribution planning, the ability to control VAR flow from a central hub, the ability to control voltage at substations and on lines, and the ability to leverage AMI meter information. He said these are foundational to building a modernized grid. Making these investments now will make ISOP more effective than it would otherwise be. Consolidated Tr. vol. 10, 30.

DEP Late Filed Exhibit 5

On September 8, 2020, at the request of Commissioner Hughes during the consolidated evidentiary hearing, DEP filed Late Filed Exhibit 5, which shows the revenue requirement savings that DEP expects from the GIP programs agreed to in the Second Partial Stipulation. That unverified exhibit shows a revenue requirement reduction of $6.4 million in 2023, and $7 million in 2024, growing to $27.6 million in 2032. The exhibit showed that the majority of the benefits in 2032 ($17 million) are due to fuel savings from the DSDR to CVR conversion initiative.

Public Staff Supplemental Testimony

In his September 15, 2020 supplemental testimony Public Staff witness Tommy Williamson testified that during the update period of March – May 2020, DEP closed to plant at least $52.8 million of GIP investments. He stated that about $15.8 million of that was for SOG segmentation and automation projects on 135 circuits. The Public Staff sampled ten of those circuits and discovered that only three of them were fully enabled with SOG functionality. He stated that the remaining seven require additional reclosers and circuit enablement and are expected to be fully enabled in 2021. Williamson stated that DEP had told the Public Staff that the personnel who program the software to enable each segment had not been able to keep up with the increasing pace of expenditures. Williamson concluded that these investments nonetheless are "used and useful" and eligible for inclusion in rate base, even though they were not fully enabled.

DEP Supplemental Rebuttal Testimony

Witness Oliver responded to witness Williamson's supplemental testimony by stating that the timeframe is longer than Duke would like between construction completion and enablement of SOG segmentation and automation projects. He stated that once DEP is fully staffed it will take about 12 weeks between construction work completion and enablement. Oliver said that these 12 weeks are needed to schedule multiple interdependencies between the reliability engineers who create the device settings, the model builders who program the devices into the software and facilitate testing and validation, and coordination with grid management technicians to ensure devices present correctly in the distribution control center. Witness Oliver testified that as COVID restrictions ease DEP intends to begin building the staff required to reach the targeted 12-week timeframe. He stated that meeting the 12-week timeframe can be an additional metric tracked pursuant to the Second Partial Stipulation with the Public Staff.

Discussion and Conclusions

In Sub 1142 DEP did not seek recovery of any GIP (Power Forward) costs, although Public Staff witness Floyd testified that the Company had already spent $18.2 million on such investments. At that time, DEP planned to spend $1.6 billion in capital from 2017 through 2021 on grid modernization. Several parties urged the Commission to establish a separate proceeding to resolve the scope and pace of DEP's grid modernization efforts, which the Commission declined to do. Instead, the Commission approved a stipulation between DEP and the Public Staff that required DEP to host a technical workshop regarding the Company's Power Forward grid investments.

Power Forward was also an issue in DEC's 2018 general rate case, Sub 1146. In that proceeding the Commission rejected DEC's request for either a rider or deferral accounting for Power Forward expenditures and suggested that DEC collaborate with stakeholders in developing any future grid improvement programs.

In the current DEP rate case, witness Oliver testified that, in response to the Commission's recommendation in the DEC 2018 Order, the Company convened three in-person stakeholder workshops and a series of webinars addressing the Company's plans for grid improvement. Tr. vol. 16 at 144-45. Witness Oliver stated that the Rocky Mountain Institute acted as a neutral facilitator in each of the three workshops and prepared detailed, post-project reports that were filed with the Commission at the conclusion of each workshop. *Id.* at 145. Witness Oliver testified that because of these stakeholder engagements the Company made significant changes to its portfolio of investments, provided cost-benefit analyses and underlying data sources and worksheets for all applicable programs and projects to stakeholders, and responded to questions concerning distributed energy resources. *Id.* at 145-46. The Commission recognizes the effort expended by the Companies to engage with stakeholders, as the Commission had directed them to do.

In the instant proceeding, subsequent to its initial request for approval to defer costs related to $987.8 million in spending on 16 programs aimed at addressing its grid modernization needs, DEP worked with the Public Staff to reduce further its planned investment, and the Public Staff agreed to DEP's requested deferral accounting treatment for that investment. Specifically, DEP seeks deferral of the capital costs associated with GIP investments made from June of 2020 through December of 2022 for the following programs, the descriptions for which are derived from witness Oliver's direct testimony (including his Exhibit 10), and augmented with testimony from the consolidated portion of the evidentiary hearing:

(1) SOG. This initiative has three components: capacity, connectivity, and automation. Capacity projects expand substation and distribution line capacity to allow customers to be served from two directions. Connectivity projects create tie points between circuits. Automation projects provide intelligence and control, enabling the grid to dynamically reconfigure around trouble and better manage distributed energy resources. The advanced distribution management system is software that leverages the intelligence from the grid with information from substation equipment, intelligent switches, and distributed energy resources to optimize power flow and minimize the impact to customers when faults occur. It is the centralized system for managing the grid.

(2) Integrated Volt/VAR Control (IVVC). Allows the distribution system to optimize voltage and reactive power via remotely operated substation and distribution line devices such as voltage regulators and capacitors. The grid operator can lower the voltage to reduce energy consumption and system losses. Witness Oliver stated that DEP plans to convert its DSDR system[14] to operate in

[14] The Commission approved DSDR as an energy efficiency program in 2009 in Docket No. E-2, Sub 926. DEP files annual DSDR reports in that docket, most recently on July 14, 2020. That report shows

conservation voltage reduction (CVR) mode at a cost of $10 million. During the consolidated portion of the hearing, witness Oliver testified that DEP plans to test the impact that the DSDR-to-CVR conversion would have on the system's load reduction capability. Consolidated Tr. vol. 6, 26.

(3) Distribution Automation. Includes four programs. The hydraulic-to-electronic re-closer program involves the replacement of oil-filled devices with modern, remotely operating reclosing devices that support continuous system health monitoring. The fuse replacement program replaces one-time-use fuses with automatic devices that reset themselves. The underground system automation program modernizes the protection and control in underground systems that serve critical, high-density areas such as urban business districts and airports. The system intelligence and monitoring pilot develops advanced diagnostic tools that help engineers and technicians address electrical disturbances on the distribution system.

(4) Transmission System Intelligence. DEP will replace electromechanical relays with remotely operated digital relays, implement intelligence and monitoring technology capable of providing asset health data to drive predictive maintenance programs, deploy remote monitoring and control of substation and transmission line devices, and install resiliency projects that leverage state of the art equipment such as digital relays, gas breakers, and other equipment enabled with SCADA communication and remote monitoring and control capabilities to rapidly respond to system outages or disturbances.

(5) ISOP. Involves the integration and refinement of existing system planning tools and the development of new analytical tools. It is a multi-year program to build and integrate the tools and processes needed to accommodate an integrated approach to plan and operate the electric utility system. One example is the Morecast circuit level load forecasting tool, which is necessary to enable the Advanced Distribution Planning tool.

(6) DER Dispatch Tool. Will provide system-wide visualization and control of large-scale DERs, enabling DEP to model, forecast, and dispatch them. It will provide operators with a more automated and refined toolset to optimize management of both utility- and customer-owned DERs to meet system stability requirements.

(7) Power Electronics for Volt/VAR Control. This limited deployment of advanced solid-state technologies like static VAR compensators will help DEP manage power quality issues associated with increasing DER penetration.

that in 2019, DEP used DSDR to reduce demand 14 times, achieving between 87 MW and 260 MW of peak reduction each time, and 7,785 MWh of total energy savings.

(8) Cyber Security. These programs include cyber security enhancement, protection from electromagnetic pulses and electromagnetic interference, a device entry alert system, and distribution line cyber protection and secure access device management. Consolidated Tr. vol. 5, 39.

The Second Partial Stipulation constitutes agreement between the Public Staff and DEP as to the decision to incur GIP costs and the deferral accounting treatment of those costs. The Public Staff expressly reserved the right in the agreement to review actual costs incurred by DEP for reasonableness and prudence in future proceedings. Additionally, DEP and the Public Staff agreed to develop jointly biannual reporting requirements to track GIP expenditures that receive deferral treatment, including: (1) tracking costs for each program, including the number of devices installed, types of projects completed, or circuits modified or impacted; (2) reporting on a circuit and substation level; (3) summarizing actual benefits compared to projected benefits; (4) reporting the operational system impacts of SOG and IVVC; and (5) providing data and analyses that inform any significant changes to the scope of the SOG and IVVC programs. The first report would cover spending in the last six months of 2020. Additionally, DEP agreed to assess the cost-effectiveness of GIP programs in an on-going manner and to undertake a cost-benefit analysis for its automated lateral device program.

Further, the Public Staff and DEP agreed that the costs deferred would be limited to only capital costs (return, property tax, and depreciation) related to plant in service and incremental expenses net of operating benefits, for plant placed in service between June 1, 2020, and December 31, 2022, as well as a return on the deferred balance of such costs during the deferral period. The deferral would cease upon the effective date of any general rate case order in which the associated eligible plant is included in rate base. The Public Staff and DEP agreed that if no general rate case order recognizing the entirety of eligible plant in rate base is issued by December 31, 2024, DEP would cease deferral of all eligible net costs and carrying costs and consult with the Public Staff regarding the beginning of amortization of the deferred costs for regulatory accounting and ratemaking purposes.

In addition to the Second Partial Stipulation with the Public Staff, DEP reached five settlements with multiple other parties relative to its GIP deferral request. Several of those settlements address cost allocation issues related to costs incurred for the GIP programs, which are not ripe for decision by the Commission at this time. Because the issues of cost allocation for costs associated with the GIP programs are not before the Commission for a determination in this proceeding, the Commission considers them to be properly reserved for the cost recovery proceeding, which would be DEP's next general rate case.

Under North Carolina law, a stipulation entered into by less than all parties in a contested case "should be accorded full consideration and weighed by the Commission with all other evidence presented by any of the parties in the proceeding." *CUCA I,* 348 N.C. at 466. Further, "[t]he Commission may even adopt the recommendations or provisions of the nonunanimous stipulation as long as the Commission sets forth its reasoning and makes 'its own independent conclusion' supported by substantial evidence on the record that the proposal is just and reasonable to all parties in light of all the evidence presented." *Id.*

Because of the structure and scope of the stipulations reached with the various settling parties, the Commission concludes that the GIP programs for consideration are those contained in the Second Partial Stipulation, which includes a commitment by DEP to withdraw its request for deferral accounting treatment for individual GIP programs that are not specifically supported by the Second Partial Stipulation. The settlements with the other intervenors either provide express support for or non-objection to the deferral of costs associated with the programs specifically agreed to in the Second Partial Stipulation.

The Commission understands the Second Partial Stipulation, considered together with the settlements reached between DEP and other intervenors, to have resolved GIP-related issues between DEP and the majority of intervenors that filed testimony relating to GIP issues. The only parties whose active opposition to GIP in the form of filed testimony were not resolved through these settlements are NC WARN and CUCA.

The Commission concludes that the Second Partial Stipulation, as well as the additional settlement agreements, constitute material evidence in this proceeding regarding GIP-related issues and should be afforded significant weight by the Commission.

At the direction of the Commission, the Company engaged with stakeholders to redefine its grid modernization plans following its 2018 rate case proceeding. The scope of the Company's GIP proposal was further narrowed through additional negotiation with the Public Staff, and programs that had been criticized as being routine operation expense as opposed to grid modernization were dropped from the proposal that ultimately was adopted in the Second Partial Stipulation. At the expert witness hearing Public Staff witness Thomas testified that the Public Staff had investigated each program included in the Second Partial Stipulation, focusing on costs and benefits, and has an understanding of what ratepayers are getting, in terms of fuel savings and reduced operational costs. The Commission is persuaded by the testimony of witness Thomas that the Public Staff has an understanding of the operational benefits that have been estimated by DEP and the type of reliability improvements that customers might see, and concludes that the Public Staff entered into the Second Partial Stipulation with this understanding. *See* Consolidated Tr. vol. 7, 69. Also, the Commission gives weight to the testimony of DEP witness Oliver as to his confidence in the cost estimates underlying the GIP proposals as well as cost control measures that the Company will implement. Consolidated Tr. vol. 10, 23-25, 42-43.

The Company and the Public Staff witnesses provided significant reassurance to the Commission that the eight GIP programs included in the Second Partial Stipulation are defined on the record as to scope, implementation, and initial budgets; that the Company has significant experience in implementing similar programs in many cases; and that rigorous project management and evaluation mechanisms will be utilized by the

Company in implementing and monitoring these programs. These mechanisms will include reporting to the Commission at six-month intervals on the progress of such implementation as anticipated in the Second Partial Stipulation.

The test historically utilized by the Commission in assessing the propriety of a request for deferral accounting treatment is whether the costs proposed for deferral are extraordinary in type and extraordinary in magnitude. Tr. vol. 15, 1523. However, this test is not the exclusive basis upon which the Commission has previously allowed deferral of costs incurred by utilities, and, as was noted in the 2018 DEC Rate Order, the Commission may approve a deferral within a general rate case with parameters different from those applied in contexts other than general rate cases. 2018 DEC Rate Order at 149. Unlike the consideration of a deferral request outside a general rate case when a single expense is being brought to the Commission's attention, in a general rate case the Commission has the benefit of a complete picture of the Company's financial health, of all of its expenses and revenues, and the impact of a deferral of future costs on the revenue requirement being approved in that general rate case. Therefore, the typical concerns are not an issue in the present case because the request is not being determined outside of a general rate case, but rather is being determined in a general rate case, a proceeding in which all items of revenue and costs are reviewed.

Additionally, the Commission's 2018 DEC Rate Order declared that "with respect to demonstrated [grid modernization] costs incurred by DEC prior to the test year in its next case, the Commission authorizes expedited consideration, and to the extent permissible, reliance on leniency in imposing the 'extraordinary expenditure' test." *Id.* Public Staff witness Maness explained that the Public Staff took special notice of the language in the Commission's 2018 DEC Rate Order that suggests leniency regarding the magnitude of costs or financial impacts necessary to justify deferral. Consolidated Tr. vol. 7, 32, 48; Tr. vol. 15, 1600. Further, in explaining why the Public Staff opposed the Company's Power Forward proposal but supported the GIP proposal set forth in the Second Partial Stipulation, witness Maness indicated that the Power Forward rider proposal was not clear on whether and the extent to which costs would be reviewed at the time the Company seeks cost recovery. Consolidated Tr. vol. 7, 44. Public Staff witness Maness also expressed concern at the Company's position that, absent deferral approval, the Company would reduce spending on the GIP programs by 80%. *Id.* at 45. Finally, Public Staff witness Maness testified that the Public Staff "agreed to the settlement in terms of settling all of the issues in the case, and there was give-and-take amongst all of them" and further that "in the interest of settling the case, [the Public Staff] think[s] that it's acceptable for deferral to be approved for the expanded scope of programs that are reflected within the settlement." *Id.* at 49. Witness Maness made clear that the Public Staff was not generally abandoning its initial position in the proceeding, which involved application of the traditional deferral test, but that in the interest of settlement of issues agreed to the GIP proposals as reflected in the Second Partial Stipulation.

Given the evidence of record, the Commission accepts the terms of the Second Partial Settlement as to the GIP proposals, including the request for deferral accounting treatment. However, in approving the request for deferral accounting treatment for the GIP programs set forth in the Second Partial Stipulation, the Commission deems it necessary and appropriate to limit the GIP costs that will be allowed deferral accounting treatment to $400 million, consistent with DEP's planned spending, in order to provide an incentive for DEP to manage its GIP spending cost-effectively and mitigate the risk of over-spending. In light of the fact that the Commission retains the ultimate authority to deny recovery of imprudently incurred or unreasonable costs – even if such costs have been previously deferred – the Commission finds that adequate protections against risks inherent in the design, budgeting, implementation, and monitoring for the eight settled GIP programs are adequately addressed in the record, in the Second Partial Stipulation, and by the implementation of the $400-million limitation on the deferral.

NC WARN witness Powers testified that the Commission should reject the Company's GIP as unreasonable on the basis that the GIP projects are indistinguishable from traditional spend projects, with no formal applications or associated evidentiary process to evaluate the reasonableness or potential alternatives for these proposed expenditures. Witness Powers also contended that the stakeholder workshops used to develop the GIP were essentially sales presentations by the Company that did not adequately review the scope and cost of the GIP. In spite of the contentions of NC WARN, the Commission concludes that the work undertaken by the Company in the stakeholder process to refine its grid modernization proposals and, thereafter, the additional work with the Public Staff to further limit the proposals and associated spending distinguish the proposals from previous proposals. This conclusion is further supported by the uncontested testimony of Company witness Oliver, who described the GIP program proposals as "foundational" to managing the transition from a grid consisting primarily of one-way power flows to a two-way power flow dynamic. Consolidated Tr. vol. 5, 40.

CUCA witness O'Donnell generally took issue with the GIP proposals, expressing concern over costs associated with the programs and the similarity to the Power Forward proposal that had been rejected by the Commission. However, witness O'Donnell did provide several recommendations as to how the Commission should address the GIP proposals, including making cost recovery contingent upon the Company meeting the reliability targets as set forth by DEP in its cost benefit analyses and allowing cost recovery if and only if the reliability targets are reached every year. The Commission notes the concerns expressed by CUCA witness O'Donnell but gives weight to the fact that, per the terms of the Second Partial Stipulation, DEP and the Public Staff will jointly develop metrics to monitor the implementation and measure the effectiveness of the programs. Further, DEP agreed to report such metrics, including cost-effectiveness, for each of the agreed upon programs on a regular basis beginning with expenditures made during the last six months of 2020. On this point, at the expert witness hearing DEP witness Oliver testified that the Company will be able to measure the performance of and the benefits achieved by the programs. Additionally, Public Staff witness Thomas indicated comfort with the parties' ability to measure GIP program performance and confirmed the Public Staff's intention to monitor GIP program performance closely. Thus, the Company has committed to report to the Commission on the effectiveness and cost-effectiveness of the programs. The Commission will hold the Company to this commitment, and the Commission anticipates that these data will be taken into consideration by the Commission in the cost recovery proceedings.

DEP witness Oliver stated that there is currently no 'Phase 2' of DEP's GIP plan, and that any future plan would be based on collaboration with stakeholders. The Commission notes that DEP has embarked on a robust stakeholder engagement effort in order to develop ISOP, which effort the Company described in its Integrated Resource Plan 2020 Biennial Report filed September 1, 2020, in Docket No. E-100, Sub 165. DEP states in that filing that it is committed to implementing the basic elements of ISOP in its 2022 IRP. DEP should ensure that its future grid modernization investments, those occurring beyond 2022, are informed by that ISOP process.

As to the DSDR-to-CVR conversion, the Commission will honor the Second Partial Stipulation between DEP and the Public Staff and allow the conversion costs to be deferred. However, DEP shall nonetheless: (1) determine the amount of peak reduction capacity that will be lost due to the conversion and propose a method of replacing that lost capacity in Docket No. E-100, Sub 165 (IRP docket); (2) file in the IRP docket and Docket No. E-2, Sub 926 (Sub 926) a revised DSDR-to-CVR conversion cost-benefit analysis that incorporates the cost of replacing any lost peak reduction capacity; and (3) file an updated report in the IRP docket and Sub 926 that estimates CVR's anticipated capital and O&M costs, peak reduction, and energy savings for the next 10 years. DEP shall file this information by August 1, 2021. DEP shall bear all risk of disallowance of DSDR-to-CVR conversion costs if the cost-benefit analysis shows that conversion costs, including replacement peak reduction capacity, exceed benefits.

The Commission notes that DEP's GIP is inconsistent as to its proposed treatment of new GIP-driven DSDR-related costs. While the CVR conversion costs are included in the deferral requested in this rate case, DEP apparently plans to recover other DSDR-related GIP costs in the Company's DSM/EE rider. The Commission finds this bifurcated approach to cost recovery for CVR/DSDR to be potentially problematic. In addition, the Commission notes that fuel savings from CVR will flow to all customers via the fuel rider (as DSDR fuel savings do currently), while the bulk of costs for the legacy DSDR system are being recovered via DEP's DSM/EE rider. Pursuant to N.C.G.S. § 62-133.9(f), industrial customers can avoid DSM/EE rider charges and hence would receive the additional fuel savings benefits of the CVR conversion without paying their share of a major portion of the related system costs. Due to this misalignment of costs and benefits the Commission will require DEP to file a proposal to move all DSDR and CVR costs into base rates when the Company files its next general rate case.

The Commission has carefully reviewed the evidence on DEP's GIP proposal in this docket and concludes that acceptance of the Second Partial Stipulation's provisions between the Public Staff with DEP related to the GIP programs is appropriate and is supported by material and substantial evidence of record.

The Commission's acceptance of the GIP provisions of the Second Partial Stipulation is limited. The Commission's decision simply allows DEP to treat costs incurred in pursuing the settled GIP programs as regulatory assets pending a prudence and reasonableness determination in a later rate case. DEP remains fully at risk for the reasonableness and prudence determination of its GIP costs and for their ultimate recovery from customers, as would be the case if DEP simply undertook these programs without a deferral and then sought recovery of the costs in a rate case. The only difference is that deferral of these costs allows certain between-rate-case earnings impacts of these costs to be held on the books of DEP as a regulatory asset and preserves them for possible future recovery if they are determined by the Commission, in a future proceeding, to be just and reasonable, prudently incurred, and otherwise eligible for recovery from customers.

The Commission concludes that the parties have compromised significantly to reach agreement, as evidenced by the Second Partial Stipulation, and deferral treatment for the GIP programs identified in the Second Partial Stipulation is reasonable and in the public interest. The Commission recognizes that the Company has undertaken stakeholder engagement efforts since the last rate case and made considerable efforts in this regard, as directed by the Commission. Through the stakeholder process, and continuing through this rate case proceeding, the Company has significantly narrowed its deferral request. The accounting deferral request, as modified by the Second Partial Stipulation with the Public Staff, and supported by other intervenor settlement agreements, represents a set of programs that can be classified as grid modernization, along with reporting requirements that will ensure collaboration and transparency as investments are made. The approval for deferral accounting treatment is limited to $400 million, which will incent DEP to manage its spending, and any amounts actually spent and deferred by the Company will be subject to review for reasonableness and prudence before any such costs are passed on to customers. Finally, the deferral accounting treatment approved in this proceeding shall be considered specific only to this case in light of the evidence of record in this proceeding and shall not be given any precedential value by the Commission regarding any future general rate case proceeding or deferral request or any other proceeding before the Commission at any point in the future.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 40

Regulatory Asset and Liability Rider

The evidence supporting this finding of fact is found in the verified Application and Form E-1; the testimony and exhibits of DEP witnesses Smith and Pirro, Public Staff witness Dorgan; and the entire record in this proceeding.

Summary of the Evidence

In the 2018 DEP Rate Order the Commission ordered that "if DEP receives revenue for any deferred cost for a longer period of time than the amortization period approved by the Commission for that deferred cost, the Company shall continue to record all revenue received for that deferred cost in the specific regulatory asset account established for that deferred cost until the Company's next general rate case."

DEP witness Smith testified that the Company has continued to record all revenue received for deferred amounts related to regulatory asset and liability accounts until the Company's next general rate case – this proceeding – in compliance with the Commission's directive. Tr. vol. 13, 134. The Company requested that customer rates be decreased by $2.1 million as a result of regulatory assets or liabilities that have been over-amortized since the last general rate case. *Id.* at 133. The Company proposed a Regulatory Asset and Liability rider (RAL-1) to return this balance to customers over a one-year period. *Id*. at 134. Smith Exhibit 5 shows the calculation of the resulting net over amortization balance.

Witness Pirro testified that a proposed uniform rate of $0.00005 per kWh for Rider RAL-1 is derived in Smith Exhibit 5 and will be effective for 12 months. Tr. vol. 11, 1112. He noted that the proposed Rider RAL-1 tariff is provided in the Company's proposed tariffs filed as Exhibit B to the Company's Application. *Id*.

Public Staff witness Dorgan testified in his direct testimony that the Public Staff had reviewed the Company's proposed Regulatory Asset and Liability Rider and agreed with the calculation. The rider was reflected in Public Staff witness Maness's Second Stipulation Exhibit 1, supporting the Second Partial Stipulation.

No other parties opposed or otherwise addressed the proposed Rider RAL-1.

Discussion and Conclusion

The Commission finds and concludes that the Company's proposed Regulatory Asset and Liability rider (RAL-1) is just and reasonable, consistent with the Commission's directive relating to the treatment of net over-amortizations of expired regulatory assets and liabilities since the Company's last base rate case and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 41-48

Tax Act Issues

The evidence supporting these findings of fact is found in the verified Application and Form E-1; the Public Staff First and Second Partial Stipulations, and the CIGFUR Stipulation; the testimony and exhibits of DEP witnesses De May, Smith, Newlin, Panizza, Hager, and Hevert, Public Staff witnesses Dorgan and Hinton, CIGFUR witness Phillips, and CUCA witness O'Donnell; and the entire record in this proceeding.

Summary of the Evidence

DEP Direct Testimony

Witness De May

Witness De May noted that the impacts of the federal Tax Cuts and Jobs Act of 2017 (Tax Act) have been incorporated into the Company's request, as outlined in the testimony of witnesses Smith and Panizza.

Witness Smith

Witness Smith described DEP's proposed changes to the existing EDIT-1 Rider[15] and the addition of a new EDIT-2 Rider to refund federal and state income tax related amounts owed to customers due to Tax Act and recent reductions to North Carolina state corporate income tax rates.

Witness Smith stated that in addition to increased revenue from tariff rates for electric service, the Company requests that customer rates be increased by $7.4 million, as presented in Smith Exhibit 3, through a revision in the existing North Carolina EDIT-1 Rider and decreased by $127.6 million, as presented in Smith Exhibit 4, through the proposed EDIT-2 Rider. Witness Smith maintains that the two EDIT riders represent amounts due from or owed to customers related to tax rate changes and EDIT, in addition to what is reflected in the proposed revenue increase in Smith Exhibit 1. Witness Smith maintained that Smith Exhibit 4 illustrates the EDIT-2 Rider to refund various categories of EDIT to customers, including federal EDIT, North Carolina EDIT related to the 2019 change in the tax rate from 3.00% to 2.50%, and the provisional revenues resulting from the Tax Act.

Witness Smith noted that the reduction as provided in the Tax Act became law on December 22, 2017. The Company began deferring the provisional revenues associated with this reduction in income tax rates starting January 1, 2018, through service rendered November 30, 2018, into a regulatory liability account. Witness Smith maintained that the Commission, in its order dated November 26, 2018, in Docket No. M-100, Sub 148, approved a base rate decrement proposed by the Company to pass through the tax benefits of the federal corporate income tax rate reduction. Witness Smith stated that, accordingly, the Company commenced passing through the revenue impacts of the reduction in the federal corporate income tax rate to customers starting December 1, 2018. She noted that this decrement is eliminated through the proposed rates in this proceeding, which reflect the new lower federal corporate income tax rate of 21.00%.

[15] EDIT-1 was established in Sub 1142 to flowback $42.577 million per year over a four-year period to reflect the reduction in the North Carolina corporate income tax rate. This flowback period was agreed to by DEP and the Public Staff and accepted by the Commission.

Witness Smith explained that DEP's proposed EDIT-2 Rider contains the following five categories of benefits for customers, as follows:

(1) Federal EDIT – protected;

(2) Federal EDIT – unprotected, Property, Plant, & Equipment (PP&E)-related;

(3) Federal EDIT – unprotected, non-PP&E-related;

(4) Deferred (provisional) revenue - federal income tax; and

(5) NC EDIT.

Federal EDIT - protected

Witness Smith explained that these amounts are generally related to PP&E and there are specific IRS requirements mandating that this amount be returned to customers no more quickly than as prescribed by the IRS. The amortization period the Company is using for Protected EDIT is called the Average Rate Assumption Method (ARAM) and results in a Year 1 amortization rate for this category of 3.70%. Also, as witness Panizza noted, protected amounts ultimately become unprotected over time. As such, the Company estimated this amount and captured this transition from the Protected to Unprotected category on Smith Exhibit 4, Page 1, Line 3.

Federal EDIT – unprotected-PP&E related

Witness Smith stated that these amounts are also related to PP&E but do not fall under the IRS guidelines for protected status. Because the Company would have paid these amounts to the IRS over the remaining life of the underlying property, the Company is proposing to return these amounts to customers over a 20-year period. As noted by witness Panizza, this approach balances the customer's and the Company's interests, minimizing customer rate volatility and addressing the Company's cash flow concerns.

Federal EDIT – unprotected non-PP&E related

Witness Smith stated that these amounts are not related to PP&E but are related to items such as regulatory assets and liabilities and other balance sheet items. The Company proposes to return these amounts to customers over a five-year period. In addition, the Company has included in this category amounts transitioning from the Protected category to Unprotected status. Like the EDIT that results from the reduction in the federal corporate income tax rate, there are EDIT balances that resulted from the reduction in the North Carolina corporate income tax rate.

Deferred (provisional) revenue – federal income tax

Witness Smith stated that as directed in Docket No. M-100, Sub 148, the Company began deferring, effective January 1, 2018, the impact on customer rates of the reduction in the federal corporate income tax rate from 35.00% to 21.00%. She stated that beginning December 1, 2018, a new rate decrement approved by the Commission in Docket No. M-100, Sub 148 reflects the lower federal corporate income tax rate. She asserted that after December 1, 2018, deferral amounts are related to continuing accrual of returns on the deferral balance. She noted that Smith Exhibit 4, Page 1, Line 8, shows the projected balance of this liability as of February 2020. Witness Smith maintained that the Company will continue to defer the impact from March 1, 2020, through the effective date of new rates in this case. She stated that those additional amounts are not being estimated now but will be included in the Year 2 EDIT-2 Rider calculation. Witness Smith stated that the Company is proposing to incorporate the refund of these provisional revenues in the EDIT-2 Rider proposed in this case, over a two-year period.

NC EDIT

Witness Smith testified that in the Company's last general rate case in Sub 1142, the Commission approved a four-year State EDIT Rider (EDIT-1 Rider) to return EDIT resulting from reductions in the state corporate income tax rate in prior years. The State EDIT-1 Rider currently in place does not include EDIT related to the reduction in North Carolina state corporate income tax rate from 3.00% to 2.50% effective January 1, 2019. The Company is proposing to incorporate the refund related to this reduction in the North Carolina state corporate income tax rate from 3.00% to 2.50% in the EDIT-2 Rider proposed in this case, over a five-year period.

Witness Smith further noted that the Company's proposed EDIT-2 Rider will include the annual amortization for each of these five categories of benefits. She stated that the North Carolina retail amounts can be seen on Smith Exhibit 4, Page 1, Columns A through E. Witness Smith maintained that since these EDIT amounts are a reduction in rate base, rate base will increase as these amounts are refunded to customers. She stated that, as such, the rider also calculates the adjustment to increase rate base resulting from the refund of EDIT to customers; this is shown in Smith Exhibit 4, Page 2, Column L. She noted that Column M shows the revenue requirement equal to the sum of the amortization and return; Column N shows the revenue requirement grossed up for the Commission's regulatory fee and uncollectible expense; and the amount in the Year 1 row on Smith Exhibit 4, Page 2 of $127.6 million decrease is the rider amount that is being proposed in this case.

Witness Smith explained that the Year 1 rider amounts are based on the balance of EDIT at December 31, 2018, as described by witness Panizza and are updated to reflect the expected balance at August 31, 2020, when the proposed rider is expected to be implemented. She stated that this projection will be further updated to reflect actual February 29, 2020, balances, as well as the latest ARAM rate, prior to the hearing.

Witness Smith maintained that years two through five are shown for illustrative purposes and that the actual rider amounts for those years may change based on several factors:

(1) additional adjustments to any of the balances on Rows 1 through 4 of Smith Exhibit 4;

(2) a change in the ARAM rate. Witness Smith detailed that the Company updates this rate annually and the most current rate must be used when establishing customer rates;

(3) future rate cases. Witness Smith maintained that in future rate cases, the EDIT balance in base rates shown in Column J and the rate of return used to calculate Column L of Smith Exhibit 4, Page 2 would be updated based on what is approved in that case; and

(4) the retention factor used to calculate Column N, which will be updated to reflect any future changes in the Commission's regulatory fee.

She stated that the Company proposes to file the rider amounts, along with the spread to the classes and derivation of the rate for each subsequent year, with the Commission annually in this docket by September 30, for rider rates effective December 1. Witness Smith maintained that the Year 1 EDIT-2 revenue requirement, shown in Smith Exhibit 4, was provided to witness Pirro who explains the derivation of the rider rate in his testimony. She noted that witness Hager explains how the amounts were allocated to the customer classes in her testimony.

Witness Smith filed supplemental direct testimony wherein she updated the EDIT calculation to reflect known changes to the EDIT balances and amortization amounts as of February 2020. She noted that she revised her Exhibit 4 to reflect the completion of Duke Energy's 2018 federal income tax return. She stated that the annual amortization percentage for federal protected EDIT has been updated to an actual amount that aligns with the most recently filed federal income tax return, which is the Company's best estimate for the following year's protected EDIT amortization. Witness Smith maintained that this update is necessary to comply with federal tax normalization rules and was referenced in her direct testimony. Witness Smith asserted that, additionally, the federal unprotected PP&E-related EDIT and State EDIT components of the rider were updated to reflect minor revisions to the EDIT amounts.

Witness Newlin

Witness Newlin testified about the impact of Tax Act on the Company's credit ratings. He stated that the rating agencies have identified several challenges the Company faces in maintaining its credit ratings, one of which is the reduced cash flow resulting from federal tax reform. Witness Newlin maintained that Moody's is particularly focused on downward pressure on financial metrics due to regulatory lag, including in the recovery of coal ash basin closure costs and storm expense. Moody's also points to federal tax reform putting pressure on the Company's credit metrics due to reduced cash flows.

Witness Newlin further noted that in January 2018, Moody's published a report outlining its initial assessment of the impact of tax reform on the regulated utility sector. Witness Newlin stated that in addition to outlining the negative impact of tax reform on utilities and the regulatory uncertainties related thereto, Moody's changed the rating outlook of 24 utilities (including Duke Energy Corporation) from "Stable" to "Negative." Witness Newlin noted that the January 2018 Report updated Moody's 2019 outlook for the regulated utility sector to "Negative" from "Stable." He stated that a key factor in this outlook change was a decline in cash flows – "the combination of a lower tax rate and the loss of bonus depreciation as a result of the [Tax Act] means that utilities and their holding companies will lose some of the cash flow contribution from deferred taxes on an ongoing basis." Of the 24 utilities Moody's placed on "Negative" outlook on January 16, 2018, Duke Energy was the first to have its outlook resolved. Witness Newlin noted that in August 2018, Moody's issued a credit opinion restoring Duke Energy's outlook to "Stable." He asserted that Moody's attributed this to an expectation that Duke Energy will maintain supportive regulatory relationships and highlighted credit supportive rate case outcomes across several regulatory jurisdictions.

Witness Newlin testified that, if unmitigated, the reduction in cash flows will erode DEP's credit metrics, citing a June 2018 Moody's report. Witness Newlin stated that certain factors that could lead to a downgrade including "[a] deterioration in the credit supportiveness or emergence of a more contentious regulatory relationship which negatively impacts cash flows or the timeliness of cost recovery, particularly with regards to coal ash remediation recovery in North Carolina." Moody's identifies "credit supportive regulatory relationships" as a credit strength and elaborates that "[t]he stable outlook reflects our expectation that [Duke Energy Corporation] will maintain supportive regulatory relationships in all of its jurisdictions."

Witness Newlin stated that deferred taxes are not large pools of money that the Company holds in an account somewhere; instead, they are collections that occur over time based on the life of the underlying assets, which the Company has used to invest in its business during the deferral period. Witness Newlin therefore argued that customers have benefitted because the Company has used these "zero interest" loans to finance its business rather than incurring financing costs that are passed on to customers. Witness Newlin argued that when the tax rate changes, either up or down, leveraging the over and undercollection of these funds in a proper and principled manner benefits both the Company and its customers. He maintained that if adjusting rates to account for tax changes is done in a haphazard manner, it can cause rate volatility and harm to customers as well as the financial health of the utility.

Witness Newlin also testified that if, for example, the Commission determines that refunds resulting from decreases in tax rates should be provided to customers as quickly as possible, then it logically follows that DEP would need to access the capital market to raise cash to provide for the shortfall in funds collected. Witness Newlin argued that this unplanned and possibly large capital raise could put stress on DEP's credit quality and rating. Were any future tax increases also collected from customers as quickly as possible Witness Newlin maintained that customers would then experience an immediate, perhaps dramatic, increase in rates, which the Commission attempts to avoid by way of gradualism. He argued that that same concept of gradualism should apply equally to tax decreases and must be considered just as it might with tax increases.

Witness Newlin noted that DEP has ADIT where it has collected a book level of tax expense for tax liabilities from customers. He stated that because the Internal Revenue Service (IRS) rules provide certain financial incentives, such as accelerated depreciation and credits, actual tax expense can be lower for tax purposes than book expense and create timing differences between when the costs are recovered from customers versus when the costs are payable to the government. Witness Newlin maintained that often IRS income is lower in the early years because the IRS commonly offers credits, accelerated depreciation, and other incentives so that the Company is collecting from customers at a level higher than what is actually being paid in cash taxes. Witness Newlin noted a liability to pay those taxes in the future is thus recorded to the Company's balance sheet because it is not a permanent reduction in taxes but rather a delay in payment of cash taxes. Witness Newlin maintained that a deferred tax liability is a customer benefit; it serves as a reduction to rate base and, because the Company does not earn on rate base to the extent that the Company has a deferred tax liability on the balance sheet, customers effectively save the weighted average cost of capital on the deferred tax balance.

Witness Newlin further noted that because of the change in the corporate income tax rate from 35.00% to 21.00%, the Company now has EDIT, which is excess ADIT that must be returned to customers where the Company previously collected from customers at the higher 35.00% tax rate and will now have a lower payment obligation at the new 21.00% tax rate. Witness Newlin maintained that had the federal corporate income tax rate not changed, thus creating EDIT, the average flowback of the property-related deferred taxes would have been 22 years. Thus, he testified that DEP proposes to flow these property-related EDIT back to customers over a 20-year period. Witness Newlin argued that an EDIT flowback period that more closely matches the life of the underlying asset smooths out the cash flow hit the Company would take as it returns EDIT to customers and lessens the need for the Company to raise those funds from investors and third-parties. Similarly, he asserted that, had the tax rate increased, the Company would not request to recover the increased amount instantly or over a short timeframe for the same reason – because the higher taxes would be paid over the life of the asset. Witness Newlin argued that addressing the impact on customer rates over a longer period also helps avoid rate volatility.

Witness Newlin provided examples of several other state utility commissions that have taken steps to mitigate the negative impacts of tax reform.

Witness Panizza

Witness Panizza noted that the Tax Act reduction in the corporate tax rate is accompanied by many other provisions having varying impacts on the revenue requirement, and that these impacts must be considered particularly as they relate to cash flow. He outlined several articles that supported his testimony.

Witness Panizza stated that DEP's $1,177 million (or $1.2 billion) of EDIT, as of the end of 2018, falls into three different buckets. Witness Panizza stated that the first bucket contains approximately $823 million is what is called protected EDIT – that is, EDIT related to the Company's investment in PP&E, whose flowback treatment is expressly made subject to IRS normalization rules by the Tax Act. He noted that the normalization rules of the Tax Act require protected EDIT to be flowed back over the remaining lives of the property giving rise to the deferred tax balance. He also noted that the remaining two buckets of EDIT, totaling approximately $354 million as of the end of 2018, is unprotected under IRS rules, and, therefore, subject to flowback in a timeframe subject to the Commission's discretion.

Witness Panizza stated that the second bucket, and the lion's share of unprotected EDIT, totaling approximately $327 million of the $354 million, still relates to the Company's investment in PP&E. Thus, he maintained that this portion of unprotected EDIT is not required to be normalized under the Tax Act. Witness Panizza stated that although both buckets are property related, the Internal Revenue Code protects one but not the other. However, witness Panizza argued that the rationale for normalization should apply to this portion of EDIT as much as it applies to protected EDIT. He noted that the assets represented in this bucket have an average life of approximately ten years for DEP, although the Company's proposal uses a shorter 20-year period over which to accomplish this flowback.

Witness Panizza stated that the third and final bucket, totaling approximately $27 million as of the end of 2018, is non-PP&E-related, unprotected EDIT, and mostly consists of the EDIT that transitioned from protected to unprotected during 2018. Witness Panizza maintained that these balances are as of the end of 2018; the Company has made and may make additional adjustments to these amounts in 2019, as protected amounts ultimately become unprotected over time.

Witness Panizza argued that the Company's proposal included in this case provides immediate benefit from the Tax Act and continues benefitting customers through the return of deferred taxes over time. He concluded that the Company's proposal further complies with accounting requirements while preserving the Company's credit rating by not creating undue pressure on cash flows.

Witness Hager

Witness Hager stated that the Company has allocated the benefits in the EDIT-2 Rider to the classes based on the accumulated deferred income taxes (ADIT) allocator.

She stated that she has reviewed this allocation and finds that it is reasonable based on cost causation principles. Witness Hager maintains that since the EDIT amounts were previously part of ADIT as explained by DEP witnesses Smith and Panizza, this is consistent with how the amounts were allocated prior to the federal corporate income tax rate change and reasonably reflect how the benefits were created.

CIGFUR Testimony

Witness Phillips stated that DEP should be ordered to return EDIT to its customers as soon as possible. He stated that he has reviewed DEP's proposal to refund EDIT to its customers and that, in his opinion, the Commission should use its discretion to require DEP to refund the federal unprotected EDIT as expediently as possible to the ratepayers. Witness Phillips recommended that the Commission reject DEP's proposal to refund the federal unprotected PP&E-related EDIT over a prolonged period.

CUCA Testimony

Witness O'Donnell stated that EDIT are taxes that consumers have paid to the utility in prior years that were planned to be paid to the taxing authority in future years. He maintained that EDIT is essentially a product of the tax difference between accelerated depreciation and straight-line depreciation. Witness O'Donnell noted that in ratemaking, taxes are calculated using straight-line depreciation and that the utility uses accelerated depreciation to calculate its taxes. He argued that therefore the utility pays lower taxes than is the case with straight-line deprecation used for ratemaking purposes. Witness O'Donnell maintained that as an asset ages, the taxes that the Company collected but did not pay to the government are eventually paid so that the net result, over time, is the consumer pays the tax owed by the utility.

Witness O'Donnell noted that when the federal government reduced the corporate income tax rate from 35.00% to 21.00% in 2017, EDIT was created on DEP's books. He stated that as a result the EDIT funds need to be returned to their rightful owner, the North Carolina retail customers of DEP. Witness O'Donnell further noted that the rate increases sought by DEP in this rate case are significantly lower when the return of EDIT is considered.

Public Staff Testimony

Witness Dorgan

Witness Dorgan testified that DEP did not adjust to exclude any EDIT from rate base but instead proposed to handle each of the five categories in a single rider, with rate changes occurring each year based on the proposed amortizations for these categories, which range from five years to 39.6 years. Witness Dorgan maintained that the five categories of refunds should be handled separately due to the differing natures of the amounts and the amortization periods. He asserted that this provided a more transparent means of tracking the Tax Act and North Carolina tax-related refunds to customers for each year. Therefore, witness Dorgan made several recommendations regarding federal EDIT.

First, witness Dorgan recommended an adjustment to remove the federal protected EDIT from the EDIT-2 Rider proposed by DEP and instead leave that amount in rate base. He proposed to amortize the federal protected EDIT over 39.6 years in base rates and to remove the first year of amortization from the deferral amount for purposes of this proceeding.

Next, for federal unprotected EDIT, witness Dorgan stated that tax normalization rules are very clear and that EDIT is either protected or not. He maintained that the Company's assertion, that it should only return unprotected PP&E-related EDIT over the same period of time it would have paid the funds to the IRS had the Tax Act not been passed, is not supportable by any logical accounting or ratemaking principle. Witness Dorgan recommended removing the EDIT regulatory liability associated with all the unprotected differences from rate base and placing it in a rider to be refunded to ratepayers over five years on a levelized basis, with carrying costs. Witness Dorgan noted that the immediate removal of federal unprotected EDIT from rate base increases the Company's rate base and mitigates regulatory lag that might occur from refunds of federal unprotected EDIT not contemporaneously reflected in rate base. He argued that refunding the federal unprotected EDIT over five years allows the Company to properly plan for any future credit needs while refunding ratepayer dollars in a reasonable time.

Witness Dorgan stated that for the provisional revenues collected since the federal corporate income tax rate decreased from 35.00% to 21.00% he recommended placing that amount in a separate levelized rider, to be amortized over a one-year period. He also removed the balance from the working capital schedules since he recommended a refund over one year. Witness Dorgan maintained that a one-year amortization period is consistent with the period approved by the Commission in the most recent rate cases of Aqua North Carolina, Inc.; Carolina Water Service, Inc. of North Carolina; and Piedmont Natural Gas Company.

Finally, witness Dorgan proposed that the State EDIT amount be removed from rate base and placed in a separate rider to be returned over one year with a return on the balance. He noted that this period is consistent with the Commission's Order in Dominion Energy North Carolina, Docket No. E-22, Sub 532.

Witness Dorgan noted in his supplemental direct testimony that he updated the amount of each EDIT category to reflect the amounts on Smith Supplemental Exhibit 4, Line 8 that was filed on March 13, 2020.

Witness Hinton

Witness Hinton provided testimony on how the Public Staff's proposals impact DEP's credit metrics. He noted that DEP provided the Public Staff with the projected credit metrics, specifically the Cash Funds from Operations over Total Debt (FFO/Debt) under both the Public Staff's proposed five-year flowback proposal and DEP's proposed 20-year flowback proposal for federal unprotected EDIT. Witness Hinton asserted that the shorter time allowed to return the unprotected EDIT to customers results in lower credit metrics for the forecast period of 2020 through 2023.

Witness Hinton maintained that the 20-year flowback of unprotected EDIT results in a higher average projected FFO/Debt ratio of approximately 40 basis points. Witness Hinton noted that as outlined in Moody's March 28, 2019 Credit Opinion, a FFO/Debt ratio that is between 21.00% and 23.00% qualifies for an "A" rating. Witness Hinton stated that given that the predicted FFO/Debt metric with a five-year flowback is below 21.00% in only one year, 2020, and the other metrics are 22.00% and 24.00% through 2023, he believed that unexpected financial developments such as significant reductions in DEP's cash flows or significant increases in its debt balances would have to occur in order to trigger a ratings downgrade.

Witness Hinton also noted that Moody's places 40% weight on financial strength as measured by its quantitative financial metric, 50% weight on the regulatory climate, and 10% weight on utility diversification. He stated that the 50% weight on regulation focuses on two areas: the regulatory framework and the ability to recover costs and earn returns. Witness Hinton maintained that the regulatory framework relates to rate setting by the governing body, credit supportive legislation that is responsive to the needs of the utility, and the way the utility manages the political and regulatory process. Witness Hinton stated that the ability to recover costs and earn returns on its investments relates to the assurance that the regulated rates will be based on prescribed and clear ratemaking methods. Witness Hinton asserted that, while awarding the least weight in its rating methodology to diversification, Moody's positively views utilities with multinational and regional diversity in terms of regulatory regimes and diversity in the economics of its service territories.

Witness Hinton further maintained that DEP has other means to finance the EDIT flowback over a five-year period that would not adversely affect its FFO/Debt metrics. He noted that the filed E-1, Item 38 contains DEP's financial forecast, which indicates that DEP projects being financed with 48% long-term debt and 52% common equity every year through 2023. Witness Hinton stated that from 2020 through 2023, Item 38 indicates that DEP plans to issue a total of $3.45 billion in long-term debt and infuse $2.83 billion to Duke Energy Corporation (parent). Witness Hinton argued that this indicated that an option may exist for DEP to offset some of its debt issuances through a reduction in its planned contributions to its parent, which would better allow the Company to maintain its Moody's A2 credit rating or, in the event of a downgrade, the ability to restore its current credit rating. Witness Hinton noted that DEP witnesses De May and Newlin stressed the importance of maintaining DEP's credit quality, which Moody's places as the second highest rated among Duke Energy Corporation and its other six electric utility subsidiaries as follows:

Moody's Credit Ratings

	Long-Term Issuer Rating	First Mortgage Bonds
Duke Energy Carolinas	A1	Aa2
Duke Energy Progress	A2	Aa3
Duke Energy Indiana	A2	Aa3
Duke Energy Florida	A3	A1
Duke Energy Ohio	Baa1	A2
Duke Energy Kentucky	Baa1	N/A
Duke Energy Corporation	Baa1	N/A

Witness Hinton also noted that Duke Energy Corporation announced that it would issue approximately 29 million shares of common stock which will result in approximately $2.5 billion of net proceeds. He argued that this additional equity could allow DEP to decrease its projected equity infusions to the parent Company, alleviating the need to issue as much new debt and reducing the possibility of a downgrade.

Witness Hinton stated that DEP expects that a one-notch downgrade by Moody's to A3 would increase the investor-required bond yield by 10-basis points. He stated that DEP maintains that this estimate was based on market conditions associated with a normal or typical period in the bond market and, when considering the burden associated with DEP's long-term debt, it was worth noting that Moody's A-rated long-term utility bond yields as of February 29, 2020, are 3.11%, the lowest in over 30 years. He argued that in view of DEP's financial forecast, he believed that the added cost of debt capital from a downgrade to an A3 rating will not be burdensome on the Company and its customers. Witness Hinton further noted that since 1975 DEP has had five upgrades and three downgrades and that it does not appear that any downgrade resulted from the 1986 change in the federal corporate income tax rate.

Witness Hinton concluded that based on his review of the FFO/Debt credit metrics, it is unlikely that spreading the refund of EDIT over five years will result in a debt rating downgrade and that a five-year flowback as recommended by the Public Staff is reasonable and fair to DEP's ratepayers and DEP.

Finally, witness Hinton stated that he would expect that regulatory lag would be effectively removed by the cash payment to compensate DEP for its storm costs of approximately $668,140,000 (DEP's storm costs as of January 31, 2020). Witness Hinton argued that credit rating agencies positively view securitization of utility costs with the prompt and certain recovery from the net proceeds from the sale of the bonds. Witness Hinton therefore asserted that the securitization of the Company's storm costs should ameliorate some of the downward pressure on the Company's credit metrics.

DEP Rebuttal Testimony

Witness De May

Witness De May contested many of the recommendations set forth by the Public Staff and other intervenors in their direct testimony, asserting that if adopted by the Commission they would negatively affect the Company's financial ability to make necessary investments and help the State achieve its desired energy future. Witness De May also testified that many of the intervenors' positions are contrary to established regulatory rules and precedent, including precedent established as recently as the Company's 2018 Rate Case in Sub 1142.

Witness Hevert

Witness Hevert noted that the March 2015 Report by Moody's mentioned in witness Woolridge's testimony makes clear that utilities' cash flows have benefited from increased deferred taxes, which themselves were due to bonus depreciation. Witness Hevert noted that Moody's recognized that the rise in deferred taxes eventually would reverse. Witness Hevert stated that in January 2018 Moody's spoke to the effect of that reversal on utility credit profiles in the context of tax reform:

> Tax reform is credit negative for US regulated utilities because the lower 21% statutory tax rate reduces cash collected from customers, while the loss of bonus depreciation reduces tax deferrals, all else being equal. Moody's calculates that the recent changes in tax laws will dilute a utility's ratio of cash flow before changes in working capital to debt by approximately 150 - 250 basis points on average, depending to some degree on the size of the company's capital expenditure programs. From a leverage perspective, Moody's estimates that debt to total capitalization ratios will increase, based on the lower value of deferred tax liabilities.

Witness Hevert noted that Moody's June 2018 changed its outlook on the U.S. regulated sector to "negative" from "stable." Witness D'Ascendis adopted this testimony as his own.

Witness Newlin

Witness Newlin disagreed with Public Staff witness Hinton's recommendation for returning PP&E-related unprotected EDIT over a five-year period. Witness Newlin maintained that witness Hinton did not consider the longer-term benefits to customers of a longer flowback period. Witness Newlin stated that while customers should, and ultimately will, benefit from the overall reduction in the revenue requirement the Commission should also consider other impacts of the Tax Act, particularly as it relates to cash flow.

Witness Newlin argued that an accelerated return of EDIT over an arbitrary five-year period would adversely impact the Company's cash flow to fund ongoing operations and new infrastructure investments. He stated that an unmitigated cash flow shortfall could force the Company to rely excessively on third-party capital to fund itself, to the ultimate detriment of its financial condition. Witness Newlin noted that in Public Staff witness Hinton Exhibits 1 and 2, witness Hinton uses seven years of FFO/Debt metrics (2017 to 2019 based on historical data and 2020-2023 based on projected data as provided by the Company) and focused on a three year moving average to determine a 40 basis point degradation in FFO to Debt based on a five-year flowback as compared to the flowback as proposed by the Company in this rate case (a 20-year period for PP&E-related EDIT and a five-year flowback for non-PP&E EDIT). He stated that while Moody's presents a three-year trend in its credit opinions, credit metrics are a snapshot of an issuer's potential default risk at a point in time, and there is an inherent emphasis on forward-looking metrics when providing credit opinions, as the overall rating represents the risk of default on a prospective basis. Witness Newlin noted that as summarized in Hinton Exhibits 1 and 2, individual periods are impacted by as much as 50 basis points over the five-year period. He stated that, furthermore, this analysis focuses on EDIT flowback in isolation and does not consider the cumulative impact of other potentially credit negative proposals by the Public Staff.

Witness Newlin responded to witness Hinton's suggestion that the Company should moderate upstream equity dividends to Duke to alleviate potential credit pressures resulting from accelerated EDIT flowback. He stated that Duke has a long-term targeted dividend payout ratio of 65-75% and subsidiaries can be expected to contribute at a similar level over the long-term. Witness Newlin noted that DEP's average payout ratio over the last three years has been approximately 15%, well below this threshold, to facilitate its ongoing capital plans, large expenditures related to coal ash remediation, and investments to better serve its customers. Witness Newlin stated that, for example, during 2019, DEP did not provide any dividend to the parent, its lowest contribution in the last four years.

Witness Newlin also responded to witness Hinton's suggestion that Duke can use funds from its $2.5 billion November common equity issuance to allow DEP to further decrease equity infusions to the parent. Witness Newlin noted that the equity issuance was intended to protect Duke's credit in light of a range of scenarios related to the delay and regulatory uncertainty around the Atlantic Coast Pipeline, a key infrastructure project. Witness Newlin stated that preserving the credit quality of DEP's parent is likewise important to DEP because S&P uses a family rating methodology and weakness in the parent could lead to a lower credit opinion for the entire family of rated entities.

Witness Pirro

In his second supplemental testimony witness Pirro explained that he had revised the EDIT Rider pursuant to the CIGFUR Settlement to refund EDIT on a uniform cents per kWh basis. In his joint supplemental rebuttal testimony witness Pirro noted that returning EDIT as proposed in the CIGFUR Settlement balances out the subsidization of the residential class by nonresidential rate classes and is consistent with the rate design in the Company's last rate case.

Witness Smith

Witness Smith stated that DEP does not oppose rider treatment for EDIT but opposes the specific rider treatment as proposed by the Public Staff. The Company continues to believe that its proposed EDIT Rider is a fair balancing of relevant issues. Witness Smith disagreed with witness Dorgan that the EDIT funds rightfully belong to the ratepayers and should be returned to them as soon as reasonably possible. Witness Smith also contested witness Dorgan statement that the Company's proposal is not supportable by any logical accounting or ratemaking principle.

Witness Smith further addressed witness Dorgan's testimony that refunding the unprotected EDIT over five years allows the Company to properly plan for any future credit needs while refunding ratepayer dollars in a reasonable time. She stated that the Public Staff has provided the Company with the benefit of removing the total amount of the unprotected EDIT credit from rate base in the current case, thus providing the Company with an increase in rates to moderate any cash flow issues. Witness Smith maintained that the financing cost to the Company will be imposed ratably over the period that the EDIT is returned through the levelized rider.

Witness Smith also argued that the Public Staff's recommendation on amortization periods tends to be asymmetrical. Witness Smith stated that DEP continues to oppose this asymmetrical treatment, especially given the cash flow concerns raised by Company witness Newlin in his rebuttal testimony.

Stipulations

Public First and Second Partial Stipulations

In Section III.18 of the First Partial Stipulation DEP and the Public Staff agreed to remove the protected federal EDIT from DEP's proposed EDIT Rider and return these amounts to customers through base rates.

In Sections III.A.(2)-(5) of the Second Partial Stipulation DEP and the Public Staff agreed as follows:

> Total unprotected federal EDIT, North Carolina EDIT, and deferred revenues related to the provisional overcollection of federal income taxes (or the deferred revenues) will be returned to customers through a rider by using a levelized rider calculation methodology as described and set forth in the testimony and exhibits of the Public Staff and will be amortized over a period of five years for total unprotected EDIT and two years for North Carolina EDIT and deferred revenues.

DEP and the Public Staff also reached agreement concerning how to address changes in the federal corporate income tax rate or North Carolina state corporate income tax rate which may occur during the respective amortization periods as provided in detail in Sections III.A.(6)-(15) of the Second Partial Stipulation.

CIGFUR Stipulation

In Section IV of the CIGFUR Stipulation CIGFUR and DEP agreed that unprotected EDIT and the provisional revenues should be refunded to customers on a uniform cents per kWh basis.

Discussion and Conclusion on Return of Tax Act Items to Ratepayers

DEP and the Public Staff have stipulated on the appropriate treatment of the tax issues, as follows:

Tax Act Item	Stipulated Treatment
Protected federal EDIT	Remove from rider and amortize in base rates based on the IRS normalization rules
All unprotected federal EDIT	Levelized rider over five years
Provisional Revenues	Levelized rider over two years
State EDIT	Levelized rider over two years

DEP and the Public Staff also agreed how to address changes in the federal corporate income tax rate or North Carolina state corporate income tax rate that may occur during the respective amortization periods, as provided in detail in Sections III.A.(6)-(15) of the Second Partial Stipulation. No intervenor offered any evidence or testimony opposing the EDIT provisions of the Public Staff Partial Stipulations.

The AGO argued in its post-hearing brief that DEP should promptly return to ratepayers over $400 million in EDIT and other overcollected taxes, either as a full offset to a rate increase or as a decrease in rates. The AGO argued that these amounts should be returned to customers as soon as possible to help North Carolinians deal with challenging economic conditions. The AGO also stated that DEP has already had the full use of the funds for almost three years since the enactment of the Tax Act, which has provided considerable time for DEP to prepare for the impact of the EDIT repayment on its cash flow. The AGO further noted that reductions in federal and state corporate income tax rates have lowered operating expenses for utilities and urged the Commission to require DEP to return all of the amounts to ratepayers over no more than two years.

Based upon the record of evidence in this proceeding, the Commission gives significant weight to the First and Second Partial Stipulations concerning the tax issues in this case and finds that it is appropriate to approve those portions of the stipulations. The Commission notes that no intervenor presented testimony disagreeing with the provisions of the settlements in this regard, although the AGO contended in its post-hearing brief that federal unprotected EDIT should be returned within two years instead of five years. However, the Commission is not persuaded that it is appropriate to reject the settlements on this point based on the overall benefits of settling these matters.

Further, the Commission credits the testimony of DEC witness McManeus who testified that while the Company has been able to use amounts relating to EDIT until they are flowed back through rates, customers are benefitted in the meantime:

> Because EDIT is reducing rate base, it's reducing current rates. The Company has use of the money, as you indicate on this chart, and customers are held harmless of the Commission's decision to push this forward to a future rate case.

Consolidated Tr. vol. 4, 82. Witness McManeus further explained:

> But we've talked previously about how deferred income taxes are a source of cash to the Company and, you know, they are an interest-free source of cash. And so when we collect monies in advance of paying to the IRS, then we are able to invest that money in our business and avoid the financing . . . costs. And that is all reflected in the Company's rates.

Id. at 86; *see also id.* at 87-88.

The Commission concludes that the amortization periods as stipulated appropriately balance the interests of the ratepayers and DEP. Therefore, the Commission finds it appropriate to approve the First and Second Partial Stipulations on the tax issues in their entirety. In addition, the Commission finds and concludes that the Company's proposed revision to the approved EDIT-1 rider to reflect the change in the federal corporate income tax rate from 35% to 21%, which was supported by witness Smith and not disputed by any party, is just and reasonable and should be approved.

Discussion and Conclusion on Allocation of EDIT and the Provisional Revenues

Under Section IV of the CIGFUR Stipulation CIGFUR and DEP agreed to the refund of unprotected EDIT and the provisional revenues on a uniform cents per kWh basis. In his direct testimony DEP witness Pirro stated that the rate class revenue requirement was allocated to each rate class using the factors appropriate for Accumulated Deferred Income Taxes and divided by test year retail billed sales for each rate class to establish the year 1 credit rates. Witness Pirro stated that the derivation of the credit rate applicable to each rate class is provided on Pirro Exhibit 8 and the proposed Rider EDIT-2 tariff is provided in the Company's proposed tariffs filed as Application Exhibit B.

CIGFUR argued in its post-hearing brief that by approving the uniform cents-per-kilowatt hour refund of EDIT to customers as agreed to in the CIGFUR Stipulation the different customer classes are moved closer to parity with the actual costs to serve each class. CIGFUR argued that this position was supported by DEP witness Pirro, who testified that residential customers have historically been subsidized by other customer classes and that the proposed rate design of the EDIT Rider helps offset this subsidy. CIGFUR further argued that witness Phillips supported the positions taken by

DEP witness Pirro, agreeing that the proposed rate design of the EDIT Rider reduces subsidies uniformly by 25% and moves rates closer to cost for all customer classes. CIGFUR also argued that DEP has in the past refunded unprotected EDIT to customers using this same levelized and uniform cents per kWh method. CIGFUR stated that no party has presented a compelling reason to depart from past practice.

The Public Staff argued that it is inappropriate to refund unprotected EDIT and deferred revenue giveback overpaid by customers through the EDIT rider on a uniform cents per kWh basis rather than as a levelized EDIT credit by specific customer-class divided by each class' adjusted test year sales. The Public Staff argued that in the DEC hearing witness Pirro testified that under this method one factor would be used for all customers, with the OPT-V class receiving a larger EDIT credit than it paid in EDIT. Further, the Public Staff noted that witness Pirro admitted that base rates and EDIT should be considered separately. The Public Staff maintained that CIGFUR witness Phillips also agreed that paying EDIT on the uniform cents per kWh basis would reduce any subsidies among classes and stated his belief that it was also done in this manner in the last DEP case. The Public Staff noted that its witness Floyd advocated for using witness Pirro's original methodology that returned the EDIT to classes based on how much each class had paid. The Public Staff contended that witness Floyd testified that under the CIGFUR Settlement, approximately $30 million would be shifted from the residential, small general service, and lighting customer classes to the medium and large general service classes. Further, the Public Staff stated that witness Floyd testified that since it is possible to quantify the amount of EDIT paid by each class, it is appropriate to return that amount to the class. As a result, the Public Staff recommended that the Commission not adopt this provision of the CIGFUR Settlement because it is unreasonable and not in the public interest in this case.

Based on the entire record in this proceeding the Commission declines to adopt Section IV of the CIGFUR Stipulation because it will not achieve just and reasonable rates and therefore is not in the public interest. As the substantial evidence shows EDIT results from the overpayment of taxes by customers paying rates that include, as a portion of the rate, charges to cover the utility's anticipated federal and state income taxes. In addition, the amount of those overpayments is determinable from the Company's books and records of customer billing revenues. While different customer classes may have different rates of return (ROR), these RORs are highly dependent on the cost of service allocation methodology utilized, as well as the time period during which the cost of service study was conducted. As such, subsidy/excess issues should be resolved on the basis of equity between customer classes and their relationship to the overall ROR, not by favoring one class of customers by returning to them more than they paid in EDIT.

While in prior rate cases for DEC and DEP use of a uniform EDIT rate to allocate state EDIT[16] was agreed to as part of a settlement, no party contested the issue in those

[16] In DEC's last rate case (Sub 1146), federal EDIT was deferred until the next rate case or three years, whichever was sooner. In DEP's last rate case (Sub 1142), federal EDIT was not addressed because DEP filed its rate case before the Tax Act was signed into law in December 2017 (and effective January 1, 2018; DEP rate case Order in Sub 1142 was issued on February 23, 2018).

cases and the Commission accepted the settlement terms on state EDIT without making detailed findings of fact as to the appropriateness of a uniform rate. However, in the Commission's recent order in Docket No. E-22, Sub 562, of which the Commission has taken judicial notice in this proceeding, the Commission approved the provision of the stipulation between Dominion Energy North Carolina (DENC) and the Public Staff that the EDIT Rider credit should be allocated to customer classes based upon North Carolina basic (non-fuel) rate revenue annualized reflecting current rates for 2018. Order Accepting Public Staff Stipulation in Part, Accepting CIGFUR Stipulation, Deciding Contested Issues, and Granting Partial Rate Increase, *Application of Virginia Electric and Power Co., d/b/a Dominion Energy North Carolina for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina*, No. E-22, Sub 562, at 60-63 (N.C.U.C. Feb. 24, 2020), *appeal docketed*, No. 477A20 (N.C. Nov. 16, 2020).

With this issue now squarely before the Commission, the Commission finds it inappropriate to address any subsidy issues through reassignment of EDIT. The Commission gives substantial weight to the testimony of Public Staff witness Floyd that returning EDIT credits by customer class is a more equitable method by which to return EDIT. Thus, the Commission concludes that in this case it is inappropriate to refund the unprotected EDIT and provisional revenues to customers through the EDIT rider on a uniform cents per kWh basis and that rather these items should be refunded as a levelized EDIT credit by specific customer-class divided by the adjusted class test year sales.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 49-50

Cost Allocation Methodology

The evidence supporting these findings of fact is found in the verified Application and Form E-1; the Public Staff Second Partial Stipulation and CIGFUR Stipulation; the testimony and exhibits of DEP witnesses Hager and Pirro, Public Staff witness McLawhorn and Floyd, CIGFUR witness Phillips, and NCJC et al. witness Wallach; and the entire record in this proceeding.

Summary of the Evidence

DEP Direct Testimony

DEP witness Janice Hager testified that the purpose of the cost-of-service study is to align the total costs incurred with jurisdictions and customer classes responsible for the costs, and that cost causation is a key component in determining the appropriate assignment of revenues, expenses, and rate base among jurisdictions and customer classes. Witness Hager testified that costs are classified according to their cost-causation characteristics, and that these characteristics are typically defined as demand-related, energy-related, or customer-related. The cost-of-service study (COSS) supporting the Company's proposed rate design in this proceeding allocates the demand-related production and transmission costs based upon a jurisdiction's and customer class' coincident peak responsibility occurring during the summer, otherwise known as the Summer Coincident Peak (SCP) cost allocation methodology.

Witness Hager testified that distribution costs are classified as either demand-related or customer-related. Witness Hager summarized different methodologies for determining the customer-related component of distribution costs. DEP incorporated the concept of "Minimum System" into its COSS for allocating costs to customers. Witness Hager testified that this is appropriate for allocation of customer-related distribution costs. After the Company determines the customer-related costs using the Minimum System Method (MSM), the remainder of distribution costs are classified as demand-related and are allocated based on Non-Coincident Peak (NCP) Demand.

Witness Hager further testified to DEP's use of the MSM and stated that every customer requires some minimum amount of wires, poles, transformers, etc. to receive service; therefore, every customer caused DEP to install some amount of the distribution assets. According to witness Hager the concept DEP used to develop its Minimum System Study was to consider what distribution assets would be required if every customer had only some minimum level of usage (e.g., one light bulb).

Witness Hager stated that the reason NCP is used for allocating demand-related distribution costs is that distribution facilities serve individual neighborhoods, rural areas, and commercial districts. They do not function as a single integrated system in meeting system peak demand. Instead, the distribution system serving each neighborhood, rural area, or commercial district must be able to meet the peak demand in the area it serves whenever the peak occurs. Witness Hager stated that contribution to NCP is the appropriate measure of determining customers' responsibility for these costs because it best measures the factors that drive investment to support that part of the system.

Witness Hager testified that all costs must be allocated to the appropriate jurisdiction and customer class. If any costs are omitted or remain unallocated then the utility's rates will not allow for full recovery of the Company's operating expenses, including its approved cost of capital. Further, she testified that once all costs and revenues are assigned, the COSS identifies the return on investment the Company has earned for each customer class during the test period. These returns can then be used as a guide in designing rates to provide the Company an opportunity to recover its costs and earn its allowed rate of return.

DEP witness Pirro testified that the base rate increase has been allocated to the rate classes on the basis of rate base. According to witness Pirro this allocation methodology distributes the increase equitably to the classes while gradually moving each class's deficiency or surplus contribution to return to the retail average rate of return, within a band of reasonableness of +/- 10 percent, if possible.

Public Staff Testimony

The Public Staff recommended using Summer/Winter Peak & Average (SWPA) instead of SCP. Public Staff McLawhorn testified that SWPA more accurately and fairly reflects the planning and operation of DEP's production plant to meet the energy needs of its customers.

The Commission ordered the Public Staff to file testimony addressing at a minimum SCP, Winter Coincident Peak (WCP) and SWPA cost of service methodologies. Witness McLawhorn's testimony included an analysis of the impact of these cost-of-service methodologies across each of the retail classes of customers. Witness McLawhorn's discussion includes a comparison of class revenue increases for three of the methodologies (SCP, WCP, and SWPA). Further, the Public Staff provided some analysis of the Summer/Winter Coincident Peak (SWCP), Four Coincident Peak (4CP), and Twelve Coincident Peak (12CP) methodologies.

Public Staff witness Floyd testified that the Public Staff believes that assignment of a proposed revenue change, whether it is an increase or a decrease, should be governed by four fundamental principles. Using the ROR as determined by the COSS, and incorporating all adjustments and allocation factors associated with the proposed revenue change, the Public Staff seeks to:

(1) Limit any revenue increase assigned to any customer class such that each class is assigned an increase that is no more than two percentage points greater than the overall jurisdictional revenue percentage increase, thus avoiding rate shock;

(2) Maintain a +/-10% "band of reasonableness" for RORs, relative to the overall jurisdictional ROR such that to the extent possible, the class ROR stays within this band of reasonableness following assignment of the proposed revenue changes;

(3) Move each customer class toward parity with the overall jurisdictional ROR; and

(4) Minimize subsidization of customer classes by other customer classes.

Witness Floyd testified that the Company's assignment of its proposed revenue increase does not fully adhere to the Public Staff's recommended principles outlined above. Further, witness Floyd noted that the Public Staff intends to update its recommended jurisdictional revenue requirement and file supplemental testimony to provide a final recommendation on its recommended revenue change. Witness Floyd stated that he will provide the Public Staff's assignment of proposed revenue change at that time.

In his supplemental testimony witness Floyd presented the Public Staff's recommended distribution of revenues based on the results of the SCP, WCP, and SWPA cost-of-service methodologies and including the Public Staff's adjustments to the Company's revenue request. The assignment of the Public Staff's recommended revenue change was developed using the four basic revenue assignment principles outlined in witness Floyd's direct testimony. The Public Staff's proposed assignment adheres to each of these principles. Witness Floyd stated that his supplemental testimony provides an illustration of how base revenues and EDIT-2 credit should be assigned using the SCP and WCP cost-of-service methodologies; however, the Public Staff continues to believe that the SWPA is the most appropriate methodology for this case.

CIGFUR Testimony

CIGFUR witness Phillips recommended using WCP to reflect the fact that DEP now plans its generating system based on its winter peak demand. Witness Phillips stated that it is appropriate to classify all production investment as demand related. He argued that the capital costs are not a function of the number of kWh generated but are fixed and therefore are properly related to system demands, not to kWh sold. Witness Phillips stated that these costs are fixed in that the necessity of earning a return on the investment, recovering the capital cost (depreciation), and operating the property are related to the existence of the property and not to the number of kWh sold. According to witness Phillips, if sales volumes change, these costs are not affected, but continue to be incurred, making them fixed or demand-related in nature. He concluded that investment in generation plant is properly classified as a demand-related cost.

Further, witness Phillips argued that if an attempt were made to increase the allocation of investment to one group of customers, on the theory that those customers benefit more than others from the lower energy costs that result from the operation of a base load plant as opposed to a peaking plant, as done in the SWPA method, the analysis should be carried to its logical conclusion. The logical conclusion, according to witness Phillips, would be to fairly and symmetrically allocate energy costs to the group of customers who are forced to bear the higher capital costs allocated to them on a kWh basis. Witness Phillips stated that energy costs allocated to the high load factor class should recognize lower operating costs which result from the higher capital costs of the base load plants. Finally, he stated that the SWPA method fails to allocate lower than average fuel costs to the high load factor customers.

CIGFUR witness Phillips testified that he agrees with DEP's COSS with respect to the allocation of certain distribution facilities. According to witness Phillips the Public Staff concluded in its March 2019 report that the use of the MSM for classifying and allocating distribution costs is reasonable.

NCJC et al. Testimony

Witness Wallach testified that the Company's COSS misallocates distribution costs partly by misclassifying a portion of such costs as customer-related by relying on a flawed minimum system analysis. Witness Wallach testified that the Company's COSS allocates more distribution plant costs to the residential rate classes than is appropriate under generally accepted cost causation principles. Further, witness Wallach suggested that the Commission should direct DEP to discontinue its use of the MSM and instead rely on the "basic customer method."

In its 2018 DEC Rate Order, the Commission ordered the Public Staff to facilitate discussions with the electric utilities to evaluate and document a basis for continued use of minimum system and to identify specific changes and recommendations as appropriate. The Public Staff submitted its report on March 28, 2019, in Docket No. E-100, Sub 162. In its report, the Public Staff concluded that use of the MSM by electric utilities for the purpose of classifying and allocating distribution costs is reasonable for establishing the maximum amount to be recovered in the fixed or basic customer charge.

The basic customer method referenced by witness Wallach accounts for meters, service drops, and certain other related costs. These typically would not include transformer or wires costs. Witness Wallach referred to a report produced by the Regulatory Assistance Project (RAP) entitled *Electric Cost Allocation for a New Era*. The report states that "[t]he basic customer method for classification is by far the most equitable solution for the vast majority of utilities."

After the Company determines the customer-related costs using the MSM the remainder of distribution costs are classified as demand-related and are allocated based on NCP Demand. Witness Wallach recommended that the Commission reject the Company's use of the NCP Demand allocator to allocate distribution costs. According to witness Wallach the NCP allocator fails to accurately reflect usage patterns of residential customers and causes distribution costs to be over-allocated to the residential classes. Witness Wallach stated that to reasonably account for the effect of load diversity on distribution equipment sizing and cost, demand-related distribution costs should be allocated to rate classes on the basis of each class' diversified peak demand.

CUCA Testimony

CUCA witness O'Donnell recommended that the Commission use the same cost allocation method approved by the Commission in the Company's last fuel case, which was an equal percentage change for all customer classes. He noted that in times of fuel cost increases this allocation methodology has benefited large consumers, and in times of fuel cost decreases this allocation methodology has benefited small consumers. Witness O'Donnell concluded that what has been deemed appropriate for fuel cases for many years should also be appropriate for the allocation of coal ash costs.

DEP Rebuttal Testimony

Witness Hager discussed some of the reasons DEP support the SCP methodology:

(1) The application of the summer peak load to allocate demand-related production and transmission costs is consistent with the Single Coincident Peak Method identified in the NARUC Electric Utility Costs Allocation Manual;

(2) The predominance of the summer peak in DEP's service territory;

(3) The historical significance of the summer peak in DEP's expansion planning such that the majority of DEP's embedded generation fleet was built in response to summer peaks, thus making it appropriate to allocate these historically incurred costs;

(4) The benefit of a cost allocation methodology that encourages the shifting of usage to off-peak times;

(5) The value of sending consistent pricing signals by using a method that has been approved by this Commission for many years; and

(6) The importance of a consistent cost allocation methodology among DEP's jurisdictions so that the Company does not under or over-recover its costs.

Further, witness Hager noted that she does not agree with witness McLawhorn's assertion that the SCP methodology only addresses the peak requirement of the capacity expansion planning process and places no value on the plants' requirement to produce energy at any time other than the peak hour. Witness Hager stated that this is not the complete picture. She explained that in developing a COSS, production costs are classified into demand and energy related costs. According to witness Hager, plant capacity is considered fixed to meet demand and therefore, the cost of plant capacity was assigned to customers on the basis of their contribution to the summer coincident peak. Plant output in terms of kWh generation varies with the system energy requirements; therefore, all variable costs of production are assigned to customers based on their energy usage.

Witness Hager commented that in supporting the SWPA methodology, witness McLawhorn fails to acknowledge that the COSS in this proceeding already classifies over $2 billion of production costs (fuel, purchased power, O&M, etc.) as variable, and allocates these costs to the jurisdiction and customer classes using an energy allocator. Witness Hager stated that the SWPA method would allocate a higher portion of the fixed costs to the higher load factor customers. According to Hager, advocates for this method feel this is equitable on the theory that high load factor customers benefit from the lower energy costs that result from the operation of base load plants as opposed to the higher energy costs of peaking plants. However, witness Hager stated that proponents never carry this argument to its logical conclusion. That is, those customers allocated the higher capital costs based on energy usage should be allocated the lower variable operating costs of those same base load facilities. Witness Hager noted that if the primary theory behind the use of the SWPA allocation methodology is that fixed production plant costs are incurred to meet both capacity and energy requirements, then it seems only fair and equitable that high load factor customers should be allocated more of the lower variable energy costs, while low load factor customers should be allocated more of the higher variable energy costs.

Witness Hager also testified that she does not agree with witness Phillips' recommended use of the winter peak for the allocation of demand-related production and transmission costs. Witness Hager stated that the generation and transmission asset costs to be recovered in this proceeding were constructed based upon customers' contribution to the summer coincident peak. Therefore, SCP is the appropriate allocation methodology in this case and to focus on the converging summer and winter peaks in the rate design as has been done by Company witness Pirro. Witness Hager also expressed concerns with the volatility of the winter peak and the volatility that using a single winter peak could introduce into customer rates.

Witness Hager next turned her attention to the MSM. She stated that the NARUC cost allocation manual specifically states in the section on allocation of embedded costs that "the number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility's system." She stated that witness Wallach contends that customer connection costs are generally limited to plant and maintenance costs for a service drop and meter, along with meter reading, billing, and other customer-service expenses. Witness Hager noted that witness Wallach quotes Bonbright's Principles of Public Utility Rates to support his argument noting that the text says that metering and billing expenses are the most obvious examples of customer costs. She commented that witness Wallach fails to mention that the quoted text does not say these are the only costs. Further witness Hager stated that while it is true that Dr. Bonbright recognizes the difficulty of determining the proper allocation for the minimum system costs, he concludes that the exclusion of minimum system costs from demand-related costs is on "much firmer ground" than its exclusion from customer costs. According to witness Hager Bonbright recognizes that utilities must distribute all costs among the classes of customers in a fully distributed cost analysis. Witness Hager stated that even more important is the NARUC cost allocation manual that was developed after Dr. Bonbright's work. She commented that the cost allocation manual moved from the theoretical world of Dr. Bonbright to the reality of utilities' needs to move from development of revenue requirements to rate structures.

Witness Hager also testified that DEP does not support witness O'Donnell's proposed allocation of coal ash compliance costs. She explained that DEP used an energy allocation factor in compliance with the 2018 DEP Rate Order. Witness Hager further stated that the method proposed by witness O'Donnell is not consistent with that

Order nor does it follow cost causation principles. She noted that costs are not "caused" by the relative impact of rates on classes of customers.

Stipulations

As part of the CIGFUR Stipulation the parties agreed to meet prior to the Company's next general rate case to discuss potential costs of service methodologies that the Company may recommend for the purpose of allocating production and transmission costs. In addition, in its next general rate case the Company shall also file the results of a class cost-of-service study with production and transmission costs allocated on the basis of the SWCP method and consider such results for the sole purpose of apportionment of the change in revenue to the customer classes. Further, the parties agreed that in its next general rate case the Company will adjust its peak demand to remove curtailable/non-firm load even if it does not call the load. If the Commission approves this adjustment in the Company's next general rate case, then DEP will propose use of this adjustment in its next subsequent rate case. Finally, the parties agreed that in its next three general rate cases DEP would propose to allocate distribution expenses using the MSM; however, if the Commission orders a different approach be used in the current rate case or either of the next two rate cases, DEP may elect to propose the MSM in the next subsequent rate case after the NCUC denial, but DEP is not obligated to do so.

The Public Staff Second Partial Stipulation states that for this case only the Public Staff accepts, subject to the conditions in Section IV.B, the Company's proposal to calculate and allocate the Company's cost of service based on a SCP methodology. However, the Second Partial Stipulation also states that this provision shall not constitute precedent and shall have no effect on the Rate Design Study proposed by the Public Staff and agreed to by the Company. Further, Section IV.B states that DEP has based its filing in this docket on the SCP methodology for cost allocation among jurisdictions and among customer classes. However, the parties agreed that prior to the filing of its next general rate case the Company shall undertake an analysis of additional cost of service studies subject to the following conditions:

(1) The Company agrees to analyze and develop cost of service studies based on each of the following methodologies:

a. Single Summer Coincident Peak;

b. Single Winter Coincident Peak;

c. One that utilizes the four highest monthly system peaks (two monthly peaks in summer and two monthly peaks in winter);

d. SWPA;

e. Base Intermediate and Peak (as described in the Regulatory Assistance Project (RAP) "Electric Cost Allocation for a New Era" Manual, published January 2020); since the Company's accounting systems do not have the data developed to produce such a study, this methods may be analyzed by looking at how it has been used at another utility or with a higher level hypothetical analysis;

f. One that utilizes the twelve highest monthly system peaks in the test year; and

g. Any other identified relevant methodologies.

(2) Each methodology studied will include an evaluation of the allocation of the functions of utility service (production plant, transmission plant, distribution plant, and customer costs), including an identification of which cost components associated with these functions of utility service are fixed, and which are variable costs of service. The above methodologies only impact production and transmission allocations; however, the cost of service studies will show the allocation of all functions. For purposes of these studies, all demand and customer classified costs can be designated as fixed and all energy classified costs can be designated as variable.

(3) Each methodology studied will include an evaluation of its strengths and weaknesses on both a jurisdictional and class allocation basis.

(4) Included in the studies shall be a discussion of how the allocation of fuel and other variable operations and maintenance (O&M) expenses align with system planning.

(5) The Company shall consult with the Public Staff and any other interested parties throughout the study process.

Further, the parties agreed that the Company will continue to file annual cost-of-service studies based on both the SCP and SWPA methodologies until instructed to do otherwise by the Commission. The Company also agreed that it will not cite Commission approval of the Second Partial Stipulation as support for approval of the SCP methodology in future proceedings.

Discussion and Conclusions

The Commission gives significant weight to the testimony of DEP witness Hager and determines that having the necessary generation and transmission resources to meet the Company's summer peak, plus an appropriate reserve margin, is an essential planning criterion for the Company's system. Under cost causation principles all customer classes should share equitably in the fixed production and transmission costs of the system in relation to the demands they place on the system at the peak.

Although the Public Staff has traditionally supported the SWPA methodology, it is not unreasonable for the Public Staff to have agreed to the use of SCP in this proceeding. The Commission gives significant weight to the Public Staff's Second Partial Stipulation.

Further, the Commission gives significant weight to witness Hager's testimony concerning the Company's long history of employing the minimum system method and the method's alignment with cost causation principles. According to witness Hager's testimony, after the Company determines the customer-related costs using the MSM, the remainder of distribution costs are classified as demand-related and are allocated based on NCP demand. Witness Wallach recommended that the Commission reject the Company's use of the NCP demand to allocate distribution costs. The Commission gives little weight to witness Wallach's recommendation on this position. The Commission gives more weight to witness Hager's testimony that NCP is the appropriate measure for determining customers' responsibility for these costs.

Finally, the Commission concludes that the provisions of the CIGFUR Stipulation that commit DEP to take specific positions on certain issues in DEP's next several rate cases, such as adjustments to peak demand and use of the minimum system approach, are not relevant to any issue before the Commission in this docket. Under the guidelines set forth in *CUCA I* and *II*, a nonunanimous stipulation is evidence; however, the Commission can only use relevant evidence as the basis for its decisions. The CIGFUR Stipulation and DEP agreements on future proposals and positions in future rate cases have no relevance in this rate case, and the Commission therefore declines to accept those portions of the CIGFUR Stipulation.

Based on the evidence in this proceeding, including the stipulations, the Commission finds and concludes that the greater weight of the evidence shows that the SCP cost of service methodology provides the most appropriate methodology to assign fixed production and transmission costs in this proceeding.

The Commission finds and concludes that the Public Staff's Second Partial Stipulation was entered into by the parties after substantial discovery and negotiations, and that it represents a proposed negotiated resolution of the matters in dispute in this docket. As a result, the Second Partial Stipulation is material evidence to be given appropriate weight in this proceeding.

Moreover, as demonstrated by the opposing testimony between DEP and CIGFUR witnesses, the Commission finds and concludes that the CIGFUR Stipulation is the product of the give-and-take between the parties during their settlement negotiations in an effort to appropriately balance DEP's usage of the SCP and CIGFUR's desire to investigate a different methodology for the sole purpose of apportionment of the change in revenue to the customer classes in the next general rate case. The Commission finds and concludes that the CIGFUR Stipulation was entered into by the parties after substantial discovery and negotiations, and that it represents a proposed negotiated resolution of the matters in dispute in this docket. As a result, the provisions of the CIGFUR Stipulation not otherwise rejected by the Commission are relevant and material evidence to be given appropriate weight in this proceeding.

Further, the Commission finds and concludes that the Company's use of the MSM for cost allocation in this proceeding is just and reasonable to all parties in light of all of the evidence presented. The Commission also finds and concludes that NCP is the appropriate measure for determining customers' responsibility for demand-related distribution costs after the customer-related costs are determined using MSM.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 51

Rate Design

The evidence supporting these findings of fact is found in the verified Application and Form E-1; the stipulations between DEP and various parties; the testimony and exhibits of DEP witnesses Pirro, Huber, and Hager, Public Staff witness Floyd, NCJC et al. witnesses Wallach and Howat, NCSEA witness Barnes, Harris Teeter witness Bieber, and CUCA witness O'Donnell; and the entire record in this proceeding.

Summary of the Evidence

DEP Direct Testimony

Witness Pirro provided an overview of the Company's proposed rate design. Tr. vol. 11, 1086-88. Witness Pirro noted that when moving rate schedules and riders closer to a more cost-justified basis it is important to consider the impact upon customers and employ the principle of gradualism. *Id*. at 1089. He testified that this principle was applied in this case to update price relationships and levelize the percentage change in revenues on participants within the rate class while still moving towards a more equitable pricing structure. *Id.* at 1089-90.

Witness Pirro testified that the Company is not proposing any new peak time pricing rate designs offering real time price signals in this proceeding. He stated, however, that the Company is actively monitoring DEC's recently implemented dynamic pricing pilots to evaluate the effectiveness of dynamic pricing on residential and small nonresidential customers. According to witness Pirro, the pilots include review and analysis of rate designs that offer customers opportunities to respond to price signals to achieve a lower cost for electric service.

Witness Pirro testified that the Company's unit cost study indicates it is appropriate to raise the monthly BCC to better reflect all customer-related costs. Tr. vol. 11, 1089, 1121-22. He indicated that to do otherwise would result in customer cross-subsidization. Witness Pirro stated that the Company would normally propose the BCC for all rate classes be set to recover approximately 50% of the difference between the current rate and the full customer-related unit cost incurred to serve the customer groups. However, according to witness Pirro the Company decided in this rate case proceeding not to increase the BCC but, rather, to leave it at current rates due to past concerns raised by low-income and other advocates with respect to the level of the charge. *Id.* at 1089, 1122.

Witness Pirro also detailed, and testified in support of, the Company's proposed changes to its outdoor lighting schedules (SLS, SLR, ALS). *Id.* at 1103-07. In addition to changes to specific lighting rates, the Company also requested approval to: (1) eliminate high pressure sodium (HPS) lighting options for new installations under each lighting schedule, and offer LED lighting for those installations; (2) require replacement of existing mercury vapor (MV) lighting and related fixtures by the end of 2023; (3) modify the term for lighting contracts from one to three years; and (4) make Schedule SLR subject to the Company's Outdoor Lighting Service Regulations. *Id*. at 1104-06.

Public Staff Testimony

Witness Floyd testified that the Company made very few modifications to any of its rate schedules other than to increase individual rate elements within each schedule to accomplish the revenue increase assigned to the rate class itself, including retaining the same relationships between the summer and winter rates. Tr. vol. 15, 957. He noted that the current rates had not yet been updated to incorporate new AMI data analytics and the Company should begin incorporating AMI data into its load research efforts supporting rate design. *Id*. at 957, 966-67. However, witness Floyd stated that notwithstanding his testimony highlighting the status quo nature of the Company's rate schedules, he is generally supportive of the few proposed changes to rate schedules and service regulations discussed by witness Pirro. *Id.* at 958, 1008.

With respect to the Company's lighting rate schedules, witness Floyd indicated that he reviewed the cost data provided by the Company regarding the proposed changes to individual rates under each lighting schedule and believes the changes in rates and the related lighting services are reasonable and should be approved. *Id.* at 963. With respect to the contract terms and the application of the lighting service regulations to Schedule SLR, he concluded that both changes are reasonable attempts to consolidate the terms and conditions applicable to lighting services and each lighting rate schedule. *Id*.

Witness Floyd also stated that it is appropriate for DEP to begin working on new EV rates and to discuss design options with stakeholders. Tr. vol 15, 958. He proposed that the Commission require DEP to develop and propose EV rate designs as part of his recommended larger rate design study.

Witness Floyd further stated that the Public Staff does not object to the Company's proposal to leave BCCs at current levels for purposes of this proceeding. *See id.* at 1045-47, 1095-96.

Witness Floyd also testified that the Public Staff believes the Company should undertake a comprehensive rate design study prior to the filing of its next rate case to allow stakeholders the opportunity to participate in the discussion and he articulated six broad principles he believed were appropriate for future rate designs. *Id.* at 968-69. Witness Floyd provided several examples of utility services that justify the need for a comprehensive study, including net metering and other distributed generation resources, microgrids, energy storage, and electric vehicles (EVs). *Id.* at 969-70.

Finally, witness Floyd testified that the Public Staff supports convening a stakeholder process to address affordability issues, including the appropriate amount of the BCC.

NCJC et al. Testimony

Witness Wallach recommended that the Company's request to maintain the residential BCC at its current rate of $14.00 per bill be denied. He instead recommended that the residential BCC be reduced to $9.63 per bill, reflecting the actual cost to connect a residential customer. Tr. vol. 14, 409, 435, 437. Witness Wallach testified that consistent with long-standing cost-causation and rate-design principles, a monthly BCC of $9.63 would provide for the recovery of the cost of meters, service drops, and customer services required to connect a residential customer. He contested the Public Staff's Minimum System Report and the conclusion that it is generally reasonable to use the results of a minimum system approach for setting the maximum allowable amount that could be recovered in a basic customer charge. *Id.* at 410, 446-455.

Witness Howat also recommended that the Commission reject the $14.00 residential BCC because it inappropriately reflects usage-related costs and would result in subsidies of high-usage consumers by low-usage customers, discourages energy efficiency, and disproportionately harms certain households.

NCSEA Testimony

Witness Barnes provided extensive testimony on his proposal that the Commission direct DEP to establish EV specific rates for both home charging and commercial charging applications. Tr. vol. 14, 463-66. Witness Barnes recommended that the Commission direct DEP to file separate, targeted EV-specific tariffs for both residential and nonresidential dedicated EV charging, reflecting the core characteristics discussed in his testimony. He stated that this should occur within 60 days of the order in this rate case.

Further, witness Barnes recommended that the Commission establish an investigatory docket to receive further information and permit further discussion of EV-specific rates, lessons learned, and potential refinements.

Harris Teeter Testimony

Witness Bieber testified that DEP's proposed rate design for the SGS-TOU rate schedule significantly understates demand related charges while overstating the energy charges relative to the underlying cost components, based on the Company's own COSS.

According to witness Bieber the proposed rate design in this case would worsen the existing misalignment between SGS-TOU charges and cost causation relative to current rates. He recommended modifications to the proposed SGS-TOU rate design that he stated would improve the alignment between the rate components and the underlying costs while employing the principle of gradualism and mitigating intra-class rate impacts. Further, witness Bieber recommended that the Company study the feasibility of a multi-site aggregate commercial rate and propose a pilot program in its next rate case. Tr. vol. 15, 229-30, 252-55.

CUCA Testimony

Witness O'Donnell testified that DEP's industrial customers take advantage of the hourly pricing rate offered by the Company. However, witness O'Donnell testified that recently there have been concerns from manufacturers regarding the excessive costs of Duke's hourly prices in relation to prices found in other parts of the country. Further, witness O'Donnell testified that since Duke operates a closed system and prices its RTP costs at its own marginal costs, manufacturers are paying higher costs than necessary. He stated that he sees no reason why DEP should not be ordered to set the RTP rates at the lower of the Company's marginal cost or the price as set by the open wholesale power market, as adjusted for transmission costs and line losses for moving the power to the DEP service territory.

Hornwood Testimony

Witness Coughlan testified that DEP's LGS-RTP schedule currently has a cap of 85 customers and is fully subscribed. Witness Coughlan advocated for lifting the cap to allow customers such as Hornwood to participate. Tr. vol. 14, 550-51, 581. He stated that the 85 customers currently served under the RTP rate enjoy an unfair competitive advantage over the thousands of customers who are not allowed to receive service under this rate. Further, witness Coughlan testified that customers served under this rate have the ability to shift their load in response to strong pricing signals.

DEP Rebuttal Testimony

DEP witness Huber testified that he agreed that the Company should conduct a comprehensive rate design study. Tr. vol. 11, 1156-57. Further, witness Huber proposed that DEP complete the study by the end of the second quarter of 2021.

Witness Huber testified that the Company cannot cost-effectively implement any rate design changes until the new Customer Connect billing system is in use. He stated that because it is more cost-effective to implement new rates concurrently with the new billing system, DEP strongly favors utilizing the time prior to implementation to analyze data, convene stakeholders, and refine its proposals. According to witness Huber Customer Connect is scheduled to be implemented for DEP in the spring of 2022. Once the new Customer Connect system is fully deployed and post-deployment stabilization is achieved approximately six months later, the Company will be ready to begin implementing new rate designs.

Witness Huber stated that DEP is also open to looking into rate designs that support the adoption of electric vehicles. Tr. vol. 11, 1159. He testified, however, that the Company believes that it is inappropriate for the Commission to expedite the filing of electric vehicle-specific tariffs within 60 days of the final order in this case as recommended by witness Barnes. Rather, witness Huber suggested a study of rate designs that facilitate the adoption of EVs that provide system benefits for all customers should be a part of the comprehensive rate design study. *Id*.; *see also id.* at 1211-14.

Finally, witness Huber addressed witness Bieber's recommendation that the Commission order the Company to study the feasibility of a multi-site aggregate commercial rate and propose a pilot program in its next rate case. Witness Huber testified that DEP believes that it is premature for the Commission to order the Company to conduct such a study but stated that the Company is willing to consider the proposal in the context of the comprehensive rate design study.

Witness Pirro stated his disagreement with, and gave a number of reasons not to adopt, witness Coughlan's recommendations to increase the number of participants on LGS-RTP. *See* Tr. vol. 11, 1138, 1141, 1318-23, 1325-29. Among other things, witness Pirro explained that the hourly rates under LGS-RTP are calculated based upon the marginal or dispatch cost of the generator that is expected to serve the next kWh of system load based upon all available generating plants, and that these hourly rates are based on variable production cost data from an industry standard production cost model, which is updated daily to reflect the latest available information such as weather and load forecast, unit availability, heat rates, and variable commodity and emission costs. *Id*. at 1138-39. He also clarified that participants do not receive preferential pricing but rather the opportunity to modify their operations to respond to price signals, which carries a risk – "[i]f they don't respond, they will be paying more during those hours." *Id*. at 1321. Witness Pirro testified that a change in the rate design of the LGS-RTP tariff would require significant analysis and stakeholder engagement and suggested that this discussion should be a part of the comprehensive rate design study.

Further, witness Pirro testified that he disagrees with the recommendation of witness O'Donnell that the hourly rate be set at the lower of the Company's marginal cost or a wholesale market rate. *Id.* at 1140. He testified that the Schedule LGS-RTP hourly rates are fundamentally based on the Company's system production costs and are not designed to represent market-based pricing. According to witness Pirro the RTP product is not a market product and was never intended to provide some customers with optionality beyond the ability of the Company to provide appropriately priced service. Witness Pirro testified that the current methodology best reflects the Company's expected fuel cost and is therefore the appropriate basis under which to set hourly rates. *Id.*

Witness Pirro also disagreed with NCJC et al.'s position that the current residential BCC should be reduced. Tr. vol. 11, 1121-22. He explained that the rates and rate design supported by his testimony are based upon the COSS, including the minimum system study, performed by the Company, accepted by Public Staff, and approved in previous rate cases by the Commission. *Id.* The Company's cost-of-service studies indicate that these costs are customer costs, with the BCC designed to recover them. Witness Pirro also testified that failing to properly recover customer-related costs via a fixed monthly charge would provide an inappropriate price signal to customers and would fail to adequately reflect cost causation. *Id.* at 1123.

Similarly, witness Hager explained why it is appropriate to include uncollectible costs in the customer classification for inclusion in the BCC. *Id.* at 1067. In particular, she testified that witness Wallach's claim that uncollectible costs "tend to vary with revenues and thus with usage" is unsupported. *Id.*

Stipulations

Public Staff Second Partial Stipulation

In Section IV.C the Company agreed, consistent with the rate design principles articulated by witness Floyd, that any proposed revenue change will be apportioned to the customer classes such that: (1) any revenue increase assigned to any customer class is limited to no more than two percentage points greater than the overall jurisdictional revenue percentage increase, thus avoiding rate shock; (2) class RORs are maintained within a band of reasonableness of plus or minus 10% relative to the overall North Carolina retail ROR, and for class RORs currently above the band of reasonableness, the Company will gradually move class RORs closer to the band of reasonableness; (3) all class RORs move closer to parity with the North Carolina ROR; and (4) subsidization among the customer classes is minimized.

In Section IV.D DEP and the Public Staff agreed, as indicated by witness Floyd, that the proposed modifications to the Company's rate schedules are reasonable for purposes of this proceeding. The parties also agreed that the Commission should order a comprehensive rate design study that will address rate design questions.

In Section IV.G DEP agreed that it will develop and propose EV rate designs as part of the comprehensive rate design study.

CIGFUR Stipulation

In the CIGFUR Stipulation DEP agreed that should it independently undertake or should the Commission order a comprehensive rate design process prior to the Company's next general rate case, DEP agrees to explore the following: (1) a rate schedule targeted at high load users similar to Duke Energy Indiana's HLF rate; (2) allowing RTP customers to adjust Customer Baseline Loads (CBL) to enhance RTP usage, including additional special periods of adjustment; (3) an emergency demand response program similar to Southern California Edison's Time-of-Use-Base Interruptible Program (TOU-BIP) tariff; and (4) a rate schedule similar to the Northern Indiana PSC

Interruptible Industrial Service Rider. If there is mutual agreement between parties on the terms of any of the above-reference rates, and CIGFUR indicates that at least one of its member customers is willing to take service under such rates, DEP agrees to file said rates for approval in its next rate case filing. If DEP does not undertake a comprehensive rate design process DEP agrees to consult with CIGFUR on points 1 through 4 as mentioned above. In the event that rates proposed by DEP pursuant to points 1 through 4 as mentioned above are withdrawn by DEP or are not approved by the NCUC, DEP shall be obligated to work with CIGFUR to identify an agreeable alternative. If at least one of CIGFUR's member customers is willing to take service on the agreeable alternative rate(s), DEP agrees to file said alternative rates with the NCUC in its subsequent rate case filing.

Further, CIGFUR and DEP agreed that the LGS, LGS-TOU, and LGS-RTP on-peak and off-peak energy charges shall be increased by a percentage that is less than half of the approved overall increase percentage exclusive of any EDIT decrements for the LGS, LGS-TOU and LGSRTP and rate schedules, respectively. The demand charges for the LGS, LGS-TOU and LGS-RTP rate schedules shall be adjusted by the amount necessary to recover the final LGS, LGSTOU and LGS-RTP revenue targets, respectively.

Finally, DEP agreed to propose the uniform percentage average bill adjustment methodology most recently approved by the NCUC in DEP's 2019 fuel cost recovery proceeding in the next two annual fuel cost recovery proceedings (2021 and 2022).

The Commercial Group and Harris Teeter Stipulations

In the Commercial Group Stipulation the parties agreed that the percentage base rate increase for Rate Schedule SGS-TOU and Rate Schedule MGS shall be the same, with the exception that DEP shall have the right to adjust the rates for Rate Schedule CSE and Rate Schedule CSG more than the percentage base rate increase for Rate Schedule MGS as may be necessary to address concerns raised by the Public Staff. Further, the parties agreed that the SGS-TOU on-peak and off-peak energy charge shall be increased by a percentage that is no greater than half of the approved overall increase percentage. The demand charges for the SGS-TOU rate schedule shall be adjusted by the amount necessary to recover the final SGS-TOU target revenue.

In the Harris Teeter Stipulation the parties agreed that any GIP costs allocated to SGS-TOU customers shall be recovered via SGS-TOU demand charges. The parties agreed that the SGS-TOU on-peak and off-peak energy charges shall be increased by a percentage that is no greater than half of the approved overall increase percentage for the SGS-TOU rate schedule. The demand charges for the SGS-TOU rate schedule shall be adjusted by the amount necessary to recover the final SGS-TOU revenue target. Further, the parties agreed that the percentage base rate increase for Rate Schedule SGS-TOU and Rate Schedule MGS shall be the same. However, DEP shall have the right to adjust the rates for Rate Schedule CSE and Rate Schedule CSG more than the percentage base rate increase for Rate Schedule MGS as may be necessary to address the Public Staff's concerns.

Discussion and Conclusions

The Commission concludes that the Company's proposed portfolio of rate designs as modified by this Order, specifically including the rate design provisions outlined in §§ IV.C and D of the Public Staff Second Partial Stipulation, are just and reasonable for purposes of this proceeding. Nonetheless, as the Company and customers adopt new technologies and uses of the electric system change, rate design must evolve in order to maximize the efficiency and effectiveness of these new technologies and ensure usage of the electric system that is consistent with the public interest. The Commission recognizes the impact the results of a comprehensive rate study may have on future utility services, customers, and the economy of the State. That said, the Commission concludes that it is in the public interest to direct the Company to conduct a comprehensive rate design study (Rate Design Study) as outlined in § IV.E of the Second Partial Stipulation and further described in the testimony of witnesses Floyd and Huber, and as expanded upon herein. Based on the evidence in the record, the Commission provides the following guidance.

With respect to scope, the Rate Design Study should address, at a minimum, those rate design questions set forth in § IV.E(1)–(6) of the Second Partial Stipulation, including firm and non-firm utility services, various types of end uses (EVs, microgrids, energy storage, and DERs), the formats of future rate schedules, marginal cost versus average cost rate designs and pricing, unbundling of average rates into the various functions of utility services, and socialization of costs versus categorization of specific costs. The Rate Design Study should include but not be limited to these topics. The Commission is persuaded that in depth evaluation, debate, and discussion by and among stakeholders regarding cost to serve, rate design, and making the most efficient use of the electric system is necessary to achieve results that are in the public interest, and the Commission directs the Company to ensure that all necessary and appropriate topics are considered, to this end. For example, the Commission notes that § V.E of the CIGFUR Stipulation includes commitments by the Company in the event that the Commission directs the Company to undertake a comprehensive rate design study. Notwithstanding the foregoing, the Commission directs the Company and all parties that participate in the Rate Design Study to work cooperatively, productively, and efficiently to ensure that resources are efficiently expended on this endeavor and that the outcome aligns with the public interest.

In response to Commission questions, witness Huber confirmed that the issue of the rates and charges for services for net metering customers would be a part of the Rate Design Study. Tr. vol. 11, 1164. Thus, the Commission anticipates and expects that net metering will be considered in the Rate Design Study and that consistent with N.C.G.S. § 62-126.4(b), the Rate Design Study will address the costs and benefits of customer-sited generation.

With respect to the recommendations of NCSEA witness Barnes regarding EV charging rates, the Commission determines that the development of such rates is most appropriately evaluated in the context of the Rate Design Study as opposed to in a separate proceeding. Thus, the Commission directs the Company to include the investigation of EV rate designs in the Rate Design Study.

Similarly, with respect to the recommendations of CUCA regarding the development of interruptible rates for large industrial customers, the Commission concludes that the development of such rates is most appropriately evaluated in the context of the Rate Design Study.

Witness Floyd testified that rate design should follow the same cost causation approach underlying the COSS, such that each customer class, or customer, is responsible for an appropriate share of the costs that are planned for and incurred in order to serve them. This includes both fixed and variable costs. Witness Floyd testified that the Company's rate schedule portfolio does not align with its COSS in this proceeding. He stated that the Company continues to rely on its historical use of the SCP COSS methodology which is inconsistent with the winter peaking characteristics of the Company's overall system. However, according to witness Floyd DEP's existing rate schedule portfolio remains oriented around summer peaking utility service. Tr. vol. 15, 955-956.

Witness Floyd also testified that a comprehensive study should encompass the issues facing the utility of the future, particularly those issues discussed in testimony. Witness Floyd noted that the Company is already conducting a study of its cost-of-service. A study of rate designs should follow soon thereafter. According to witness Floyd, both are inextricably related. Rate designs should be rooted in a few broad principles that require rates to:

(1) Be forward-looking and reflect long-run marginal costs.

(2) Be focused on the usage components of service that are the most cost- and price-sensitive.

(3) Be simple and understandable.

(4) Recover system costs in proportion to how much electricity consumers use, and when they use it.

(5) Give consumers appropriate information and the opportunity to respond to that information by adjusting their usage.

(6) Where possible, be dynamic.

These guiding principles must allow consumers and users of the electric system to connect to the utility system for no more than the cost of connecting to the grid; pay for utility service in proportion to how much they use the system; and receive fair and just compensation for the energy they supply to the utility system. *Id*. at 968-69. Thus, the Commission directs the Company to undertake the Rate Design Study through the process envisioned by witness Floyd.

Further, as recommended by witness Floyd, the Commission finds that the Rate Design Study should: (1) include an analysis of each rate schedule to determine whether the schedule remains pertinent to current utility service, including whether the schedule should remain the same, be modified, or be replaced; (2) address the potential for new schedules to address the changes affecting utility service; (3) provide more rate design choices for customers; and (4) explore the feasibility of consolidating the rates offered by DEC and DEP. *Id*. at 968.

CIGFUR in its post-hearing brief stated that the rate design provisions contained within the CIGFUR Stipulation serve the public interest in that they will allow for collaborative, constructive conversations between CIGFUR and the Company in furtherance of the goal to design rates that: (1) more accurately reflect fuel costs by time of day and season and charge customers for the actual cost of fuel in a more precise manner than an annual average uniform charge on all energy; (2) promote demand-response mechanisms that offer lower rates for metered decreases in demand when reductions in demand are in the economic and operating interests of the Company and, thus, the financial interests of ratepayers; (3) allow for trade-offs between reliability and economic considerations that industrial, high-load factor ratepayers can weigh through interruptible rates, benefitting both the Company and all classes of ratepayers; (4) include real-time pricing with attendant options and risk variations; and (5) reflect that some industrial, high-load factor ratepayers have independent backup and/or cogeneration resources. The Commission finds that these goals articulated by CIGFUR will serve the public interest and should inform the work of the rate design effort.

Company witness Huber indicated that the Company is open to a third-party facilitator for the stakeholder portion of the Rate Design Study. Tr. vol. 11, 1212. The Commission agrees that the use of an independent facilitator would be appropriate and, thus, directs the Company to engage a third party for this purpose.

The Commission declines to adopt Hornwood witness Coughlan’s recommended changes to expand the availability the LGS-RTP rate schedule in this case. Witnesses Pirro and Floyd both offered convincing testimony that while this issue warrants additional study, it would be inappropriate to open the LGS-RTP rate to additional customers at this time. In particular, the Commission gives weight to their testimony relating to the burden of administering the rate, the fact that the original rate was designed for large customers, and importance of examining the greater economic implications. Tr. vol. 11, 1318-32; tr. vol. 15, 1131-32. The Commission agrees it would be more appropriate to reevaluate this rate schedule in the broader context of examining RTP and TOU opportunities during the comprehensive rate design study, and in view of the implementation of Customer Connect.

The Commission also concludes that it is premature to order the Company to propose a multi-site aggregation pilot in its next rate case, as proposed by Harris Teeter witness Bieber. Tr. vol. 15, 229-30, 252-55. The Commission agrees with DEP, however, that it is appropriate that a multi-site aggregate commercial offering be considered in the comprehensive rate design study, including the purpose of the aggregation, the impact on cost of service, the potential for revenue realignments, and the implications for other aspects of utility service outside of base revenues.

The Commission recognizes that both witness Floyd and witness Huber provided testimony about how cost of service informs and translates into rate design. The Company has agreed to consider and prepare cost of service studies using a number of methodologies in its settlements with CIGFUR and the Public Staff, however, the Commission finds that these cost of service studies are separate and apart from the comprehensive rate design study. While a rate design study would necessarily include analysis and discussion of how rate designs align with different cost of service metrics, the Commission determines that stakeholder discussion of the appropriate allocation methods (e.g., cost of service allocators) need not be included in the rate design study. Instead, the focus of the comprehensive rate design study should remain on the guidance outlined above.

All parties to the rate case proceeding should be afforded the opportunity to participate as stakeholders in the Rate Design Study. The Commission directs the Company to initiate the Rate Design Study with stakeholders no later than 30 days following the issuance of this Order.

With respect to timing, as indicated by witness Huber's testimony that the Rate Design Study will yield a detailed "roadmap" within a year, Tr. vol. 11, 1273, the Commission directs the Company to file a comprehensive roadmap and timeline for proposing new rate designs and identifying areas for additional study within 12 months of this Order. In addition, the Commission directs the Company to file quarterly status reports in the instant docket, providing, in detail, the work of the Rate Design Study participants over the previous quarter, including objectives achieved, and anticipated work to be undertaken going forward, including objectives to be achieved.

Finally, the Commission recognizes that the Rate Design Study and the affordability collaborative described hereinafter are separate but parallel efforts. To the extend the parties participating in the affordability collaborative recommend the design of new rates to offer to low-income customers, the parties should present those recommendations to the rate design study participants for consideration. Additionally, the Commission does not intend for the stakeholder processes for affordability and the Rate Design study to be mutually exclusive or contingent upon the completion of either stakeholder process.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 52-54

Affordability

The evidence supporting these findings of fact is found in the verified Application and Form E-1; the stipulations between DEP and various parties; the testimony and exhibits of DEP witnesses De May and Pirro, Public Staff witness Floyd, and NCJC et al. witness Howat; and the entire record in this proceeding.

Summary of the Evidence

DEP Direct Testimony

Witness De May testified that DEP is committed to helping customers who struggle to pay for basic needs with programs and options to assist them during times of financial hardship. He outlined several existing programs that have helped many of their customers in this regard. Witness De May stated that DEP is convinced that additional low-income energy assistance programs can be offered to aid customers in need of support. Further, he stated that stakeholder engagement is necessary to adequately develop an appropriate suite of effective options for the Commission to consider for approval. The Company requests that the Commission direct the Company to host, and the Public Staff to participate in, a collaborative workshop with interested stakeholders to address the establishment of new low-income programs.

Public Staff Testimony

The Commission's January 22, 2020 Order directed the Public Staff to "investigate DEP's analysis of affordability of electricity within its service territory as well as programs available to DEP's customers that address affordability with a particular focus on residential energy customers." In the Order the Commission directed the Public Staff to address the following issues:

(1) An overview of Lifeline Rates and whether this approach would be appropriate for North Carolina;

(2) The applicability, design, and effectiveness of DEC's Supplemental Security Income (SSI) discount;

(3) A comparison of the SSI discount to other tariffs available to customers that address affordability issues;

(4) An overview of similar affordability tariffs or plans available by the other affiliates of DEP; and

(5) The merits of using a "minimum bill" concept in lieu of a fixed customer charge.

Public Staff witness Floyd addressed each of these issues in his testimony. Consistent with the Company's request as discussed by witness De May, witness Floyd stated that the Commission should order the convening of a stakeholder process that is tasked with addressing affordability issues for low-income residential customers.

NCJC et al. Testimony

Witness Howat provided extensive testimony on issues related to affordability of electric service for DEP's lower-income residential customers, and discussed programs and policies designed to mitigate affordability challenges faced by those customers. Witness Howat outlined policy objectives and program design elements featured in effective programs, provided brief descriptions of a sampling of investor-owned utility bill affordability programs operating in the United States, and recommended that the Commission initiate a process culminating in approval of funding and implementation of enhanced low-income bill payment assistance programming and low-income residential energy-efficiency programming in the DEP service territory. Finally, witness Howat recommended that the Commission direct DEP to expand the Helping Home Fund and consider shifting it from a shareholder- to a ratepayer-funded program.

DEP Rebuttal Testimony

Witness Pirro noted that witness Howat sought changes to the Company's energy efficiency programs targeting low-income customers. Witness Pirro stated that the issue of whether DEP should propose additional energy efficiency programs or modify existing programs should be addressed in DEP's DSM/EE proceedings.

DEP witness Pirro stated that the Company is mindful of the impact of any rate increase on customers, particularly low-income customers; however, the Company does not design rates based on income but rather applies cost causation principles to the extent practical. Witness Pirro also stated that there are other means of addressing the financial needs of low-income customers, such as Company, state, and local programs, which are more effective than biasing the rate design. Nevertheless, witness De May stated that the Company supports a dialogue on ways to mitigate electricity costs for low-income customers. He stated that the Company looks forward to the opportunity to engage with its interested stakeholders in a collaborative workshop to address this important issue.

Stipulations

In the NCSEA/NCJC et al. Stipulation DEP agreed to provide, in conjunction with the concurrent commitment of Duke Energy Carolinas, LLC, an aggregate combined shareholder-funded contribution to the Helping Home Fund of $3 million per year for two years (for a total of $6 million).

Further, the parties also agreed that within six months of the effective date of the stipulation, in addition to the low-income collaborative proposed by DEP, to collaborate to design additional low-income DSM/EE program pilots to present to the DEC and DEP DSM/EE Collaborative for consideration.

In the Public Staff Second Partial Stipulation the parties agreed that the Commission should order the Company to convene a stakeholder process that is tasked with addressing affordability issues for low-income residential customers, with a timeline for the process, including deadlines for periodic reporting and filing recommendations to the Commission. The parties proposed one year for this process. The Company also agreed to make an annual $2.5 million shareholder contribution to the Energy Neighbor Fund in 2021, and 2022, for a total contribution of $5 million. Second Partial Stipulation § IV.P.

DEP witness De May discussed in his second settlement testimony how the partial settlement balances the Company's need for rate relief with the impact of such rate increases on customers. Witness De May stated that he attended public hearings held by the Commission in this matter and personally heard from many customers who are concerned about the impacts of any rate increase on their families and businesses. Witness De May stated that DEP is very mindful of these concerns. Further, he stated, in light of the current economic conditions of many customers due to the COVID-19 pandemic, the Company believes that the concessions the Company has made in the Partial Settlement fairly balance the needs of customers with the Company's need to recover substantial investments made in order to continue to comply with regulatory requirements and safely provide high quality electric service to customers. Witness De May stated that the Company agreed to make an annual $2.5 million shareholder contribution to the Energy Neighbor Fund in 2021 and 2022, for a total contribution of $5 million.

Discussion and Conclusions

The Commission gives significant weight to the testimony of Public Staff witness Floyd addressing the affordability issues raised in the Commission's January 22, 2020 order.

In addition, the Commission gives weight to the extensive testimony of NCJC et al. witness Howat concerning affordability. Witness Howat's comments on the need for low-income affordability programs, policy objectives and program design elements featured in effective programs, as well as descriptions of investor-owned utility bill affordability programs are most informative.

The Commission also gives weight to the information provided in the late-filed exhibits of NCJC et al., which are sufficiently responsive to Commission questions posed during the hearing.

The Commission gives significant weight to the provisions of the NCSEA/NCJC et al. Stipulation and the Public Staff's Second Partial Stipulation, each of which recommend a stakeholder process that is tasked with addressing affordability issues for low-income residential customers.

Based on the evidence in this proceeding, including the stipulations, the Commission finds and concludes that it is appropriate for the Company to convene a stakeholder process (collaborative) that is tasked with addressing affordability issues for low-income residential customers, with a timeline for the process, including deadlines for periodic reporting and filing recommendations to the Commission. Both Company and intervenor witnesses highlighted the need for direction from the Commission in establishing the goals and parameters of the stakeholder process.

The Commission directs that the collaborative shall abide by the same provisions and time frames set out in the recently issued DEC Rate Case Order in Docket No. E-7, Sub 1214, and hereby incorporates by reference the guidance set forth in that Order. *See* Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Customer Notice, *Application by Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, No. E-7, Sub 1214, at 176-79 (N.C.U.C. March 31, 2021).

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 55-61

Storm Costs

The evidence supporting these findings of fact is found in the verified Application and Form E-1; the Public Staff First Partial Stipulation; the testimony and exhibits of DEP witnesses De May, Jackson, and Smith, and Public Staff witness Dorgan; and the entire record in this proceeding.

Summary of the Evidence

DEP Direct Testimony

In its Storm Cost Petition, filed in Docket No. E-2, Sub 1193, the Company sought authorization from the Commission to defer certain storm response costs incurred by the Company in responding to Hurricanes Florence and Michael and Winter Storm Diego.

In its Application the Company proposed to consolidate its Storm Cost Petition with the rate case and to recover its Storm Costs through a revision to its base rates. It also proposed to consolidate its request for storm cost recovery related to 2019 storm Hurricane Dorian with its request for cost recovery related to Hurricanes Florence, Michael, and Winter Storm Diego. In the testimony of witness De May, however, the Company linked its Storm Costs recovery request to the passage of Senate Bill 559 (SB 559) – An Act to Permit Financing for Certain Storm Recovery Costs, and indicated that if that then-pending legislation was enacted by the General Assembly, the Company would seek recovery of its Storm Costs through a securitization filing instead of in base rates.

Witness Jackson detailed DEP's general storm response and recovery systems and procedures. Tr. vol. 11, 61-77. Witness Jackson also described in detail three major storms impacting DEP's system in 2018, Hurricanes Florence and Michael and Winter Storm Diego, as well as a 2019 storm, Hurricane Dorian, along with the Company's responses to these storms and the gross capital investments and O&M expense associated with those responses. *Id*. at 77-103. Witness Jackson testified that the Company's response to the storms, including its restoration efforts, was reasonable and prudent and resulted in the restoration of power to DEP's impacted customers as quickly and safely as was reasonably possible. *Id*. at 102-03.

Witness Smith proposed to recover the incremental cost in excess of normal storm expenses, including a return on the unrecovered balance, and also proposed to begin amortization of the costs when proposed new base rates became effective, and to include a return on the deferred balance through the end of the proposed fifteen-year amortization period. In its Application, DEP's Storm Costs, projected through August 31, 2020, totaled approximately $655.8 million, consisting of approximately $569.2 million in actually incurred or projected storm response O&M costs and approximately $86.6 million in deferred depreciation expense and carrying costs (calculated using the Company's approved weighted average cost of capital) on its actually incurred storm response costs. Witness Smith's second supplemental direct testimony included updated actual amounts of DEP's Storm Costs totaling $714.0 million, consisting of $567.3 million in actually incurred or projected storm response O&M costs, $68.6 million in capital investments, and $78.1 million in carrying costs (calculated using the Company's approved weighted average cost of capital through August 31, 2020).

Public Staff Testimony

Witness Dorgan testified that the Public Staff had reviewed the Storm Costs sought to be recovered in this proceeding and had concluded that they were prudently incurred. Tr. vol. 15, 750. Witness Dorgan also stated that he had made an accounting adjustment to remove these Storm Costs from the rate change request in this docket on the basis of Company witness De May's prior testimony that if the (then pending) storm cost securitization legislation was enacted, DEP would seek to recover its Storm Costs through the alternative securitization mechanism provided by that legislation. *Id*. at 749. Finally, witness Dorgan adjusted DEP's revenue request in the rate case to allow for a ten-year normalization of storm costs not sufficient to support a separate securitization filing. *Id*. at 750.

DEP Rebuttal Testimony

On May 4, 2020, in his Rebuttal Testimony, witness De May indicated that the Company looked forward to pursuing recovery of its Storm Costs through a separate securitization filing but that the Company believed that a determination of the reasonableness and prudence of its Storm Costs should be preserved in the general rate case for determination by the Commission. Tr. vol. 11, 777-78.

Public Staff First Partial Stipulation

In the First Partial Stipulation DEP and the Public Staff agreed to adjustments "to remove the capital and O&M costs associated with the Storms and to reflect a 10-year normalized level of storm expense for storms that would not otherwise be large enough for the Company to securitize." First Partial Stipulation, § III.1. The parties also agreed to a presumptive filing schedule and filing parameters for DEP's securitization filing for its Storm Costs and reserved their respective rights if such filing was not made by the Company. *Id.* at § III.2. Finally, the parties agreed that a storm cost recovery rider should be established for DEP with an initial balance of $0. *Id.* at § III.5.

More specifically regarding the filing schedule, DEP agreed to file a petition for a financing order pursuant to N.C.G.S. § 62-172 no later than 120 days from the issuance of an order by the Commission in this rate case in which the Commission makes findings and conclusions regarding the Storm Costs and the First Partial Stipulation, unless a party in the rate case appeals the Commission's order as it relates to the Storm Costs or the provisions of the First Partial Stipulation related to the Storm Costs and securitization. If an appeal is filed the 120-day limit shall be suspended until the Commission's decision is affirmed or, if not affirmed, until the issuance of a Commission Order on remand following the decision on the appeal, unless the Company chooses before that time to pursue recovery as further described below, in which case the original 120-day limit shall be deemed to have applied. Should DEP fail to file a petition within the time period specified in this paragraph, the parties agreed that, in any subsequent ratemaking proceeding held to provide for recovery of the Storm Costs, the parties reserve the right to assert their respective positions. *Id*. at § III.2.

Regarding the parameters to be followed in the securitization proceeding the parties agreed that to demonstrate quantifiable benefits to customers in accordance with N.C.G.S. § 62-172(b)(1) the Company must show that the net present value of the costs to customers using securitization is less than the net present value of the costs that would result under traditional storm cost recovery. For purposes of settlement for the Storm Costs only, the parties agreed to the following assumptions:

(1) For traditional storm cost recovery 12 months of amortization for each Storm was expensed prior to the new rates going into effect;

(2) For traditional storm cost recovery no capital costs incurred due to the Storms during the 12-month period were included in the deferred balance;

(3) For traditional storm cost recovery no carrying charges were accrued on the deferred balance during the 12-month period following the date(s) of the Storm(s);

(4) For traditional cost recovery the amortization period for the Storms is a minimum of fifteen years; and

(5) For securitization the imposition of the Storm recovery charge begins nine months after the new rates go into effect.

Id. at § III.3. The parties further agreed that the amortization of securitized Storm Costs shall not begin until the date the storm recovery bonds are issued. *Id.* at § III.4.

The parties also agreed that a storm cost recovery rider should be established in the rate case and that will be initially set at $0, and if DEP does not file a petition for a financing order or is unable to recover the Storm Costs through N.C.G.S. § 62-172, the Company may request recovery of the Storm Costs from the Commission by filing a petition requesting an adjustment to this rider. *Id.* at § III.5. In such case, DEP and the Public Staff reserve the right to argue their respective positions regarding the appropriate ratemaking treatment for recovering the Storm Costs. *Id*.

Finally, the parties agreed to file a joint petition for rulemaking to establish the standards and procedures that will govern future financing petitions under G.S. § 62-172 upon the issuance of storm recovery bonds for the Storm Costs. *Id.* at § III.6.

No other party provided evidence on DEP's Storm Costs or its storm response and recovery procedures and no party contested the conclusions of the Company and the Public Staff that DEP's Storm Costs were reasonable and prudent.

DEP filed its Storm Costs securitization financing petition with the Commission on October 26, 2020, in Docket No. E-2, Sub 1262.

Discussion and Conclusions

Based upon the evidence and the record, the Commission finds good cause to conclude that DEP's actual costs incurred to respond to and recover from Hurricanes Florence, Michael, Dorian, and Winter Storm Diego, totaling $714.0 million, and consisting of approximately $567.3 million in actually incurred or projected storm response O&M costs, approximately $68.6 million in capital investments, and approximately $78.1 million in carrying costs (calculated using the Company's approved weighted average cost of capital through August 31, 2020), were reasonably and prudently incurred, to the extent such costs represent actual amounts as of May 31, 2020. Any estimated costs as of that date or incurred afterward should remain subject to review in the financing proceeding conducted pursuant to SB 559, or to consideration for recovery in a future general rate case proceeding, pursuant to the provisions of N.C.G.S.§ 62-172(a)(16)(c). Any updates to the deferred Storm Costs projections for storm recovery activities that occurred after the hearings in this docket will be addressed in the securitization proceeding.

The Commission also accepts DEP's decision to remove its Storm Costs from the revenue requirement requested in this proceeding in favor of a separate securitization filing, and the Commission further accepts the fifteen-year normalized adjustment to

DEP's revenue requirement to account for anticipated storm expenses that are not large enough in size to securitize.

The Commission gives substantial weight to the Storm Cost provisions of the First Partial Stipulation and concludes that it is appropriate and consistent with SB 559 that DEP continue to defer its Storm Costs intended to be securitized in a regulatory asset account until the date on which the storm recovery bonds are issued pursuant to an approved financing order in accordance with N.C.G.S. § 62-172 or alternative cost recovery is sought by the Company. The amounts recorded in the regulatory asset account will be subject to review by intervening parties and the Commission in the securitization proceeding. Further, it is appropriate and consistent with the statute that DEP continue to accrue and record carrying costs, at the Company's approved weighted average cost of capital, on the deferred balances in its Storm Costs recovery deferred account pending recovery through securitization, again subject to review by intervening parties and the Commission in the securitization proceeding.

The Commission also does not object to the Company using the assumptions the Public Staff and DEP agreed to in the First Partial Stipulation to demonstrate quantifiable benefits to customers, in accordance with N.C.G.S. § 62-172(b)(1). However, the Commission makes no determination in this proceeding as to whether the assumptions and conditions agreed to by the parties are appropriate for use in the calculation of the quantifiable benefits to customers. Instead, the Commission concludes that the appropriateness of the provisions of the First Partial Stipulation regarding the assumptions and methods to be utilized in the demonstration of quantifiable benefits to customers in accordance with N.C.G.S. § 62-172(b)(1) are matters to be decided in connection with the Company's joint petition with Duke Energy Carolinas, LLC, for financing orders in Docket No. E-2, Sub 1262 (Securitization Docket). In addition, the Commission accepts the parties' agreement to file a joint petition for rulemaking to establish the standards and procedures that will govern future securitization petitions under N.C.G.S. § 62-172.

The Commission also finds appropriate and reasonable the provisions of the First Partial Stipulation regarding the filing procedure for the securitization proceeding, the agreed-to delay in beginning the amortization of securitized costs, the provisions for establishing a provisional deferral of the storm costs pending the outcome in the securitization docket, and the commitment to pursue a rulemaking proceeding for future securitizations. The Commission concludes that these provisions serve to protect the interests of the Company and its ratepayers.

Finally, the Commission accepts the provision of the First Partial Stipulation to adopt a contingent Storm Cost Recovery Rider, set at $0, as a place holder in the event that securitization of DEP's costs is denied and recognizes that DEP and the Public Staff have reserved their rights to argue their respective positions regarding the appropriate ratemaking treatment for the Storm Costs.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 62-64

Service Regulations, Vegetation Management Reporting Obligations, and Quality of Service

The evidence supporting these findings of fact is found in the verified Application and Form E-1; the Public Staff Second Partial Stipulation; the testimony and exhibits of DEP witnesses Pirro and Hatcher, and Public Staff witnesses Floyd, T. Williamson and D. Williamson; and the entire record in this proceeding.

DEP witness Pirro testified to the Company's proposed changes to its service regulations, including: a decrease in the Service Charge from $17.00 to $9.14; a decrease in the Landlord Service Charge from $5.35 to $2.00; a decrease in the Reconnect Charge during normal business hours from $19.00 to $12.94; a decrease in the Reconnect Charge outside of normal business hours from $55.00 to $19.48; an increase in the charge for a customer-requested duplicate meter test for non-demand meters from $40.00 to $45.00; an increase in the charge for a customer-requested duplicate meter test for demand meters from $50.00 to $57.00; and reductions to various other monthly facilities charges. Tr. vol. 11, 1092-93. In addition, the Company proposed to change when bills are considered past due and delinquent for nonresidential customers from 15 to 25 days to match the current requirement for residential customers. *Id*. at 1093.

DEP witness Hatcher provided testimony relating to the Company's service quality and ways in which the Company is working to enhance the customer experience. *Id.* at 840, 858. Witness Hatcher noted that customer satisfaction (CSAT) is a key focus area for DEP. *Id.* at 841. He explained that using data and analytics, the Company is executing a long-term, customer-focused strategy designed to deliver greater value to its customers. The Company's CSAT program includes both national benchmarking studies and proprietary transaction and relationship CSAT studies. *Id.* at 849-50. Witness Hatcher explained that the Company analyzes the results from these studies in vigorous monthly data review sessions, with findings driving improvements to processes, technology, and behaviors – all to continuously improve the customer experience. *Id.* at 850. Specifically, he explained that DEP measures overall customer satisfaction and perceptions about the Company via its proprietary relationship survey, the Customer Experience Monitor Survey (CX Monitor Survey). Surveys are taken from residential, small/medium business customers, and large business customers, to measure customer loyalty and the ongoing perceptions of the customer experience. *Id.* at 850. The CX Monitor Survey data is used to measure the Company's Net Promoter Score (NPS), a top metric used by companies across industries to measure customer advocacy. *Id.* at 841-42. He indicated that since 2018 the Company has seen a significant increase in its NPS, with some of the Company's highest NPS scores occurring between the months of September and December of 2018 was severely impacted by major storms. *Id.* at 851.

Witness Hatcher explained that DEP also utilizes Fastrack 2.0, the Company's proprietary, post-transaction measurement program, to measure overall customer satisfaction with the Company's operational performance. *Id.* Fastrack 2.0 was intentionally designed to complement the CX Monitor survey and provide greater insight into experiences that matter to customers and near real time feedback to front line, customer-facing employees. *Id.* at 851-52. Witness Hatcher explained that analysis of these ratings helps to identify specific service strengths and opportunities that drive overall satisfaction and to provide guidance for the implementation of process and performance improvement efforts. *Id*. Through 2018, roughly 85% of DEP residential customers expressed high levels of satisfaction with key service interactions: Start/Transfer Service, Outage/Restoration, and Street Light Repair. Witness Hatcher indicated that the Company has also implemented "Reflect" – a post-contact survey that gathers customers' immediate feedback after contacting Duke Energy by web, text, call to automated system or live agent – to provide feedback. *Id.*

Witness Hatcher further explained that the Company is working hard across its business to further improve the customer experience. *Id*. at 858. Two examples witness Hatcher provided were enhancements to the Company's integrated voice response (IVR) system and the deployment of Customer Connect. Finally, witness Hatcher explained that the Company's efforts to improve customer service is why the Company seeks approval to eliminate convenience fees for credit and debit card payments made by residential customers and to extend the due date for nonresidential to pay their bills from 15 days to 25 days to match the current requirement for residential customers. *Id*. at 862-63.

Public Staff witnesses T. Williamson and D. Williamson testified that the Commission should direct the Company to begin filing semi-annual vegetation management reports in the same manner as DEC files under the Commission's directives in Docket No. E-7, Subs 1146 and 1182. Tr. vol. 15, 354, 362. They explained that there have not been any changes to the vegetation management compliance filing since the Company's March 22, 2016 filing, which are required to be filed with the Commission in Docket No. E-2, Sub 1010. *Id*. at 358.

Witnesses T. Williamson and D. Williamson also testified about DEP's quality of service. *Id*. at 356-58. They reviewed the SAIDI and SAIFI reliability scores filed by DEP in Sub 138A; informal complaints and inquiries from DEP customers received by the Public Staff's Consumer Services Division; the Consumer Statements of Position filed in Docket No. E-2, Sub 1219CS; and the Public Staff's own interactions with DEP and its customers. *Id*. They noted that for the period 2010 through 2019, Company reports show the non-Major Event Days for the SAIDI index have been slowly and moderately worsening over time but staying stable for the SAIFI index. *Id*. The Williamsons concluded that the quality of service provided by DEP to its North Carolina retail customers is adequate.

Public Staff witness Floyd testified that he is generally supportive of the few proposed changes to service regulations discussed by witness Pirro. Tr. vol. 15, 958, 1008.

In Section IV.L of the Second Partial Stipulation DEP and the Public Staff agreed that the Commission should require the Company to file an annual report of its vegetation management performance similar to the DEC's report format filed in Docket No. E-7, Subs 1146 and 1182. In Section IV.N DEP and the Public Staff agreed that the Company's quality of service is good.

No other party offered any evidence addressing these issues. The Commission therefore finds and concludes that the amendments proposed by the Company to its service regulations and the above-discussed provisions of the Second Partial Stipulation are supported by substantial evidence and are just and reasonable to all parties to this proceeding. Therefore, given the record evidence and consistent with the Second Partial Stipulation, the Commission finds and concludes that (1) the proposed amendments to DEP's Service Regulations shall be, and are hereby, approved; (2) the Company shall file an annual report of its vegetation management performance similar to the DEC's report format filed in Docket No. E-7, Subs 1146 and 1182; and (3) the overall quality of electric service provided by DEP is good.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 65-67

AMI and Green Button Connect

The evidence supporting these findings of fact is found in the verified Application and Form E-1; the Public Staff Second Partial Stipulation; the testimony and exhibits of DEP witnesses Schneider and Pirro, and Public Staff witness Floyd; and the entire record in this proceeding.

Summary of the Evidence

DEP Witness Schneider testified that as of August 2019 DEP had installed approximately 723,000 AMI meters in its North Carolina service territory. He stated that DEP plans to continue AMI implementation through early 2021 to finish installing the remaining approximately 694,000 AMI meters. He further stated that DEP began enrolling customers in its AMI opt-out Manually Read Meter (MRM) program in April 2019, and that through August 2019 about 0.16% of DEP's customers [1,105] opted out of receiving a smart meter. Tr. vol. 11, 946-47. Witness Schneider testified that since DEP's last rate case and through June 30, 2019, the Company invested $158.3 million in AMI on a system basis, and that DEP projected that it would invest $53.3 million from July 1, 2019, through February 29, 2020. *Id.* at 947-48.

Witness Schneider further testified to the benefits of AMI, including customer access to more usage information, speedier storm outage detection and restoration, more flexibility in customer billing dates, time-of-use rate designs, and Usage Alerts at the mid-point of the customer's billing cycle. *Id.* at 948-52.

DEP Witness Pirro testified that the costs of opting out of an AMI meter could justify an increase in the MRM one-time setup fee from $170 to $180.52, and the recurring monthly fee from $14.75 to $20.75. However, DEP is not requesting to increase these fees. Witness Pirro stated that these fees have been in effect for less than a year and it would be premature to adjust them at this time. He further testified that as of August 1, 2019, there were 938 DEP customers who had requested the MRM option, and that 551 of those customers provided medical forms to have the MRM fees waived. Tr. vol. 11, 1110.

Witness Pirro also testified that DEP proposes to decrease its service connection charge from $17 to $9.14 and the reconnection charge from $19 to $12.94 during normal business hours, and from $55 to $19.48 outside of normal business hours. He stated that these reductions are based on the savings resulting from the Company no longer having to dispatch its personnel to the customer's location to perform connections and reconnections. *Id.* at 1092.

Public Staff witness Floyd testified that the Public Staff agrees with DEP's decision not to increase the MRM fees at this time. He also noted that DEP has enrolled 667 customers who qualified for the medical waiver of opt-out fees. He stated that the Public Staff believes that AMI opt-out costs that are not recovered from participants should be recovered from all DEP customers. Tr. vol. 15, Part 2, 963-66. Witness Floyd further testified that he reviewed DEP's cost calculations for the reductions in connection and disconnection charges proposed by DEP witness Pirro and that these changes are supported by the Company's calculations. *Id.* at 966.

Finally, witness Floyd testified that DEP is not presently using AMI data to develop new rate designs. He stated that this is because the Company's AMI deployment is only about 60% complete. He further stated that the Public Staff believes that as soon as practicable DEP should begin incorporating AMI data into its load research supporting both rate design and integrated resource planning and sharing and comparing its findings from the AMI data with DEC. *Id.* at 966-67.

In Section IV.H of the Second Partial Stipulation DEP and the Public Staff agreed that the Rider MRM costs that are not recovered from opt-out customers should be recovered from all DEP customers, and that the current MRM charges provide a reasonable hurdle to discourage a customer from opting out of AMI metering without a legitimate reason.

In its post-hearing brief the AGO contended that DEP's cost of implementing AMI is excessive relative to the benefits that are being offered by DEP. The AGO also stated that DEP plans to integrate AMI meters with its Customer Connect billing platform using My Duke Data Download, characterized by the AGO as a nonstandard, outdated technology. The AGO stated that DEP modeled its billing platform on older technology called Green Button Download that has more limited capabilities than the standard technology now available. The AGO maintained that DEP should be required to file revised Customer Connect plans that incorporate Green Button, or another similarly advanced standard technology, or, if that is not possible, DEP should be directed to propose an alternative plan for providing comparable access to customers. AGO Brief, at 127-30.

Discussion and Conclusions

The testimony of DEP witnesses Schneider and Pirro, as well as Public Staff witness Floyd, provides substantial evidence that DEP has deployed its AMI meters in a prudent manner and that the costs of such deployment are reasonable. Moreover, the testimony and the Second Partial Stipulation provide substantial evidence that the Rider MRM costs that are not recovered from opt-out customers should be recovered from all DEP customers.

The Commission is not persuaded by the AGO's contention that DEP should be ordered to implement Green Button. The Commission has an ongoing investigation and rulemaking in Docket No. E-100, Sub 161 to address the subject of customer and third-party access to electric usage data. Numerous parties, including the AGO, have filed comments and proposed rules, some of which include guidelines for the possible role of Green Button.

Based on the foregoing, the Commission concludes that DEP should be allowed to recover its costs of AMI deployment, and that the Rider MRM costs that are not recovered from opt-out customers should be recovered from all DEP customers. Further, the Commission concludes that it should not require DEP to incorporate Green Button into its Customer Connect billing system at this time.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 68

Focal Point Project Costs

Public staff witness Metz recommended that the capital costs related to the Focal Point Project be removed from rate base. Tr. vol. 15, 859. Witness Metz testified that Focal Point is a corporate-wide initiative to replace and upgrade older monitoring and recording equipment (e.g., cameras) with modern, state of the art equipment. He noted that once this upgrade is complete it is intended to be an overall upgrade to Duke Energy Corporation's security system. Witness Metz testified that he recommended removal of these costs because these costs were for equipment that is not fully installed and operational. Witness Metz recommended a total system cost adjustment of approximately $3 million. He stated that these should be sought for cost recovery once installed. He further noted that DEP agreed to not request cost recovery in this proceeding.

Witness Metz testified that both of his adjustments had been incorporated into the schedules and exhibits presented by Public Staff witness Maness.

In light of the evidence presented in this proceeding, the Commission finds and concludes that the adjustments to remove the costs associated Focal Point are appropriate and just. Both DEP and the Public Staff agreed that the costs related to Focal Point should be removed from rate base in the current proceeding. The Commission does not yet consider these costs ripe for cost recovery, given that they are for equipment that is not installed or operational. Accordingly, the Commission concludes that these costs should be removed from rate base at this time.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 69

Roxboro Wastewater Treatment Plant Deferral

In its Application and the direct testimony of DEP witness Smith, the Company requested an accounting order to establish a regulatory asset to defer the unrecovered net book value of its Roxboro Wastewater Treatment Plant at the time of the plant's anticipated early retirement in 2021. Application at 19; Tr. vol. 13, 165. The Company requested to amortize the costs, the remaining net book value of the plant at the time of its retirement, at the level presented in the proposed depreciation study until rates can be adjusted in the Company's next rate case. *Id.* The Company also requested permission to defer to this regulatory asset any costs related to obsolete inventory, net of salvage, at the time of retirement. *Id.*

No party contested the Company's request for an accounting order.

Based upon all the evidence presenting in this proceeding, the Commission finds and concludes that the Company's request for an accounting order for the Roxboro Wastewater Treatment Plant is reasonable and approved and the Company is authorized to amortize the costs at the level approved by the Commission in this proceeding for the applicable depreciable plant in service accounts, subject to further changes in the Company's next general rate case.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 70

Accounting for Deferred Costs

The evidence supporting this finding of fact is found in the verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

In the present case, the Commission is approving DEP's recovery through amortization of a previously deferred portion of DEP's CCR costs. A deferred cost is an exception to the general principle that the Company's current cost of service expenses should be recovered as part of the Company's current revenues. As a result, a deferred cost is not the same as other cost of service expenses to be recovered in the Company's non-fuel base rates and, therefore, should be subject to different accounting guidelines.

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

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 71

Just and Reasonable Rates

The evidence supporting this finding of fact is found in the verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

Summary of the Evidence

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

DEP witness De May testified that the Company is experiencing significant changes throughout many aspects of the electric industry, and that the investments it has made and must continue to make are designed to keep pace with evolving customer needs and expectations. Tr. vol. 11, 753. He explained that reliability remains essential as an increasingly connected population continues to expand, especially in the urban areas of North Carolina. *Id*. Witness De May also testified that the energy sector is in a period of transformation and profound change driven by technological advancements, environmental mandates, storm activity and response, energy security and resiliency efforts, as well as changing customer expectations. *Id.* at 753. As one example, he stated that DEP's customers want more information about how they consume energy and more tools that help them manage their consumption. According to witness De May, DEP is responding by investing in a more efficient distribution grid, AMI meters, and cleaner and more efficient generation units. In addition, witness De May stated that DEP is actively working toward achieving a lower carbon future by taking steps to reduce its reliance on coal-fired generation. *Id.* at 755.

Moreover, witness De May further outlined how the Company is committed to helping customers who struggle to pay for basic needs with programs and options to assist them during periods of financial hardship. *Id.* at 818 He outlined assistance programs the Company offers to help customers reduce their energy costs such as the Company's portfolio of demand-side management and energy efficiency programs, including the Neighborhood Energy Saver Program. *Id.* Indeed, as part of the Public Staff Partial Stipulations, DEP will make shareholder-funded contributions, in conjunction with the concurrent commitment of Duke Energy Carolinas, LLC, of a combined $3 million per year for two years to the Helping Home Fund, for a total of $6 million. Further, DEP will make an annual $2.5 million shareholder-funded contribution to the Energy Neighbor Fund in 2021 and 2022, for a total contribution of $5 million.

Witness De May and other witnesses described the importance of DEP's maintaining a strong financial position in order to facilitate the Company's investments in utility service infrastructure. *Id.* at 760; *see also* tr. vol. 1, 54; tr. vol. 3, 39. He stated that the Company's strong financial position and performance benefit customers by reducing DEP's cost of borrowing and cost of attracting equity capital. As previously discussed, the Commission does not set rates based on DEP's credit metrics. Rather, the Company's credit ratings and other credit metrics are the responsibility of the Company to manage. Nonetheless, the Commission has considered the evidence on potential credit impacts and given that evidence due weight as a part of the Commission's ratemaking task that requires the Commission to set rates that are fair to DEP and its ratepayers. N.C.G.S. § 62-133. The utility's access to credit at a reasonable cost is important to both DEP and its ratepayers. Both benefit if the Company can obtain credit at the best interest rates reasonably possible. The Commission concludes that the rates set herein achieve the appropriate balance of being credit supportive for DEP and fair to its ratepayers.

Witness De May also detailed how the Company is actively working toward achieving a lower carbon future by taking steps to close the final chapters on coal ash and reducing its reliance on coal-fired generation *Id*. at 755. He testified that the Company is investing in natural gas and solar, including the Company's addition of a new combined-cycle natural gas facility at Asheville and that as part of the Company's strategy to reduce its reliance on coal DEP has taken a fresh look at the viability of several of its coal-fired plants. *Id.* at 755-56. He added that the Company's high performing nuclear fleet has and will continue to provide North Carolina carbon free generation now and into the future. *Id.* at 756. For example, in 2018 DEP's nuclear fleet achieved an 88.58% capacity factor, despite significant challenges attributable to the landfall of hurricane Florence. *Id.* at 854.

DEP witness Turner described the Company's fossil/hydro/solar (FHO) generation assets and provided operational performance results for those assets during the test period. Tr. vol. 11, 970-71, 975-77. Witness Turner testified to the major FHO capital additions DEP has completed since the previous rate case, explaining that the Company has made significant investments in the coal fleet to meet environmental regulations to allow for the continued operation of active plants. *Id.* at 972. Witness Turner also discussed the addition of the Asheville CC Project units, and the retirement of the two Asheville Steam Electric Generating Plant units, anticipated by the end of 2019. In addition, she explained that the Asheville CC Project, for which DEP received a certificate of public convenience and necessity (CPCN) from the Commission in the Asheville CPCN Order, features state-of-the-art technology for increased efficiency and reduced emissions. *Id*. at 971-72.

Witness Schneider testified to DEP's installation of approximately 723,000 AMI meters in its North Carolina service territory as of August 2019, and its planned continued implementation through early 2021 for the remaining approximately 694,000 AMI meters. *Id*. at 947. Witness Schneider noted that since DEP's last rate case through June 30, 2019, the Company invested $158.3 million on new AMI meters across the system in North and South Carolina, and that the Company projected to invest an additional $53.3 million across the system between July 1, 2019, through February 29, 2020. *Id.* at 948. In addition, he testified to the customer benefits of AMI, including lower cost O&M due to remote disconnections and reconnections, customer access to more usage information, speedier storm outage detection and restoration, more flexibility in customer billing dates, and new time-of-use rate designs.

These are representative examples of the capital investments that have been made and are planned by DEP in order to continue providing safe, reliable, and efficient electric service to its customers. In this time of COVID-19 with many people working and schooling at home, the importance of safe, reliable, and efficient electric service is heightened beyond its normal level as an essential service.

Discussion and Conclusions

Based on all of the evidence, the Commission finds and concludes that the rates established herein strike the appropriate balance between the interests of DEP's customers in receiving safe, reliable, and efficient electric service at the lowest possible rates, and the interests of DEP in maintaining the Company's financial strength at a level that enables the Company to obtain sufficient capital. As a result, the Commission concludes that the rates established by this Order are just and reasonable under the requirements of the Act and serve the public interest.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 72

Revenue Requirement

The evidence supporting this finding of fact is found in the verified Application and Form E-1; the Public Staff First and Second Partial Stipulations; the testimony and exhibits of the witnesses, including DEP witness Smith and Public Staff witness Maness; and the entire record in this proceeding.

The First and Second Partial Stipulations between the Company and the Public Staff provide for certain accounting adjustments that the Company and the Public Staff have agreed upon and the Commission has approved in this Order. The stipulated issues on revenue requirement effects are detailed in Smith Second Settlement Exhibit 3, Maness Stipulation Exhibit 1, Schedule 1, and Maness Second Stipulation Exhibit 1, Schedule 1, which provide sufficient support for the annual revenue required on the issues agreed to in the Second Partial Stipulation.

The Company's calculation of the revenue requirement impact of the issues settled in the Second Partial Stipulation is an increase in the base revenue requirement of approximately $19,495,000, to be further adjusted by the Public Staff's recommendations in its testimony filed on September 15 and 16, 2020. Maness Second Supplemental and Stipulation Exhibit 1 reflects the Public Staff's revised recommended change in revenue requirement incorporating the provisions of the Second Partial Stipulation as well as the Public Staff's position on the remaining unresolved issues. The total impact on the base revenue requirement of the Public Staff's Second Partial Stipulation settled items is reflected on Maness Second Stipulation Ex. 1.

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

IT IS, THEREFORE, ORDERED as follows:

1. That the approved base fuel and fuel-related cost factors by customer class are as follows: 2.080 cents/kWh for the Residential class, 2.126 cents/kWh for the Small General Service class, 2.228 cents/kWh for the Medium General Service class, 2.204 cents/kWh for the Large General Service class, and 1.392 cents/kWh for the Lighting class;

2. That DEP shall use of a 10% contingency for future "unknowns" in the estimate of future terminal net salvage costs;

3. That DEP shall use its proposed future net salvage for mass property Accounts 364, 366, and 369;

4. That DEP shall use an average service life of 15 years for new AMI meters being deployed;

5. That DEP shall continue to use a 20-year amortization period for Accounts 391 and 397;

6. That the depreciation rates proposed by DEP in this case are approved, except as specifically modified by this Order;

7. That the depreciation rate for the Mayo Unit 1 and Roxboro Units 3 and 4 generating plants shall not be changed, and shall be based upon the remaining life of the plants, as approved in DEP's rate case in Docket No E-2, Sub 1142;

8. That upon actual retirement of each generating unit, Mayo Unit 1 and Roxboro Units 3 and 4, the remaining net book value shall be placed in a regulatory asset account to be amortized over an appropriate period to be determined in a future rate case;

9. That DEP's costs of capital investments in its coal fleet to meet environmental regulations to allow for the continued operation of active coal units shall be included for recovery in DEP's rates;

10. That the costs related to the Company's capital investments in its nuclear generation fleet shall be included for recovery in DEP's rates;

11. That the stipulations of DEP with the Public Staff, CIGFUR, Harris Teeter, Commercial Group, Vote Solar, and jointly with NCSEA and NCJC et al. are accepted and approved in part, as detailed in this Order;

12. That DEP shall recover the balance of its deferred CCR costs reduced by $261 million in the present case and shall cease to accrue financing costs on this amount as of December 31, 2020, consistent with the CCR Settlement; and that DEP shall recover the balance of its deferred CCR costs over a five-year amortization period with reduced financing costs during the amortization period calculated based on (1) DEP's cost of debt set forth in the Second Partial Stipulation, adjusted as appropriate to reflect the deductibility of interest expense, (2) an ROE 150 basis points lower than the 9.60% ROE set forth in the Second Partial Stipulation, and (3) a capital structure of 48% debt and 52% equity set forth in the Second Partial Stipulation;

13. That DEP is authorized to record its March 1, 2020, and future CCR costs in a deferred account until its next general rate case; that this deferral account will accrue a return at the overall rate of return approved in this Order consistent with the CCR Settlement;

14. That the agreed-upon accounting adjustments outlined in Smith Partial Settlement Exhibit 3, Smith Second Settlement Exhibit 3, Maness Stipulation Exhibit 1, Schedule 1, and Maness Second Stipulation Exhibit 1, Schedule 1 shall be, and are hereby, approved;

15. That the Company's revised Lead-Lag Study filed as Angers Supplemental Exhibit 3 shall be, and is hereby, approved for purposes of calculating the cash working capital amounts to be included in the Company's revised rates;

16. That DEP's request for an accounting order for approval to establish a regulatory asset to defer the North Carolina retail portion of incremental O&M expenses associated with the Company's severance program, as modified by the terms of the First Partial Stipulation, shall be, and is hereby, approved;

17. That DEP shall reduce the annual funding for the Company's Nuclear Decommissioning Trust Fund by $8.7 million;

18. That the Company's request to defer the costs related to the Asheville CC Project, as modified by the terms of the First Partial Stipulation, is approved;

19. That DEP's request for deferral accounting for GIP expenditures is approved consistent with its Second Partial Stipulation with the Public Staff and subject to the conditions set forth in this Order;

20. That DEP shall work expeditiously with the Public Staff to refine its GIP reporting requirements, as intended under the Second Partial Stipulation, and file the first report for spending during the last half of 2020 by June 1, 2021;

21. That in its next general rate case DEP shall file a proposal for moving all DSDR and CVR costs into base rates;

22. That by August 1, 2021, DEP shall file in Docket Nos. E-100, Sub 165 and E-2, Sub 926 information regarding the cost of replacing peaking capacity lost due to the DSDR-to-CVR conversion;

23. That the proposed RAL-1 Rider is approved and shall be implemented;

24. That DEP's proposed revision to its previously approved North Carolina EDIT rider (EDIT-1) to reflect the change in the federal corporate income tax rate from 35% to 21%, is just and reasonable and shall be, and is hereby, approved;

25. That the proposed EDIT Rider, as modified by the terms of the DEP and Public Staff Partial Stipulations, is approved and shall be implemented; that the protected federal EDIT will be removed from the EDIT Rider and returned to customers through base rates;

26. That the agreement between DEP and the Public Staff as outlined in the Second Partial Stipulation concerning how to address changes in the federal corporate income tax rate or North Carolina state corporate income tax rate, which may occur during the respective amortization periods, is hereby approved;

27. That the CIGFUR Stipulation allowing EDIT and the provisional revenues to be flowed back based on a uniform cents per kWh basis is inappropriate and is hereby not approved;

28. That all federal unprotected EDIT and provisional revenues shall be flowed back based on the amounts each rate class paid, as recommended by Public Staff witness Floyd;

29. That the jurisdictional and class cost allocation methodologies proposed by the Company are approved and shall be implemented;

30. That the aspects of rate design agreed upon in the Second Partial Stipulation are approved and shall be implemented;

31. That the Company's proposed modifications of certain outdoor lighting fees and schedules are approved;

32. That the Basic Customer Charges as set forth in Pirro Exhibit 7 are approved;

33. That the Company's proposed structure and pricing for Schedule LGS-RTP, as modified by the Commission's final determination of revenue requirement, should be approved;

34. That the SGS-TOU rate provisions agreed upon in the Harris Teeter and Commercial Group Stipulations are approved and shall be implemented;

35. That the LGS rate provisions agreed upon in the CIGFUR Stipulation are approved and shall be implemented;

36. That the rates for the CSE and CSG rate schedules shall be adjusted to affect a gradual movement in aligning rates with costs consistent with the guidance detailed above;

37. That the Company shall conduct a comprehensive Rate Design Study as outlined in the Public Staff Second Partial Stipulation and further described herein with broad stakeholder engagement facilitated by a third party to be engaged by the Company; that the Company shall initiate the Rate Design Study with stakeholders no later than 30 days following the date of this Order; that the Company shall file quarterly status reports in this docket detailing the work of the Rate Design Study participants; and that the Company shall file a comprehensive roadmap and timeline for proposing new rate designs and identifying areas for additional study within 12 months of the date of this Order;

38. That the Company shall convene a stakeholder process that is tasked with addressing affordability issues for low-income residential customers consistent with the terms of this Order;

39. That DEP, in conjunction with the concurrent commitment of Duke Energy Carolinas, LLC, shall make an aggregate combined shareholder-funded contribution to the Helping Home Fund of $3 million per year for two years (for a total of $6 million);

40. That DEP shall make an annual $2.5 million shareholder-funded contribution to the Energy Neighbor Fund in 2021 and 2022, for a total contribution of $5 million;

41. That the Company's Storm Costs are reasonable and prudent;

42. That the terms of the Public Staff First Partial Stipulation providing for a contingent Storm Cost Recovery Rider set at $0 are approved;

43. That DEP's request to defer the Storm Costs in a regulatory asset account until the date that storm recovery bonds are issued pursuant to an approved financing order in accordance with N.C.G.S. § 62-172, or until the Company seeks recovery of the Storm Costs through an alternative method of cost recovery, is hereby approved;

44. That the Company shall conduct an independent review and audit of its M&S inventory, to be performed by the Company's internal Corporate Audit Services department, and as further described in the Public Staff Second Partial Stipulation;

45. That within 90 days of this Order, the Company and the Public Staff shall begin collaborations on document retention, project reporting, and other reasonably applicable matters to better assist the Public Staff in future audits of plant;

46. That the Company and the Public Staff shall meet to discuss the Company's plant unitization policies and reporting obligations;

47. That the proposed amendments to DEP's Service Regulations shall be, and are hereby, approved;

48. That the Company shall file an annual report of its vegetation management performance similar to the DEC's report format provided in Docket No. E-7, Subs 1146 and 1182;

49. That DEP shall recover its costs of deploying AMI meters;

50. That DEP shall recover its Rider MRM costs that are not recovered from customers opting out of AMI meters from all DEP customers;

51. That DEP shall remove the costs associated with the Focal Point Project from rate base;

52. That DEP's request for an accounting order to establish a regulatory asset to defer the remaining net book value of the Roxboro Wastewater Treatment Plant, at the time of the plant's anticipated early retirement in 2021, and costs related to obsolete inventory, net of salvage, at the time of retirement is approved and the Company may continue amortizing the costs at the level approved by the Commission in this proceeding for the applicable plant in service accounts, and subject to further changes in the Company's next general rate case;

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

54. That DEP shall recalculate and file the annual revenue requirement with the Commission within 10 days of the issuance of this Order, consistent with the findings and conclusions of this Order. The Company shall work with the Public Staff to verify the accuracy of the filing; and

55. That DEP shall file schedules (North Carolina Retail Operations – Statement of Rate Base and Rate of Return, Statement of Operating Income, and Statement of Capitalization and Related Costs) with the Commission within 10 days of the issuance of this Order, summarizing the gross revenue and the rate of return that the Company should have the opportunity to achieve based on the Commission's findings and determinations in this proceeding.

ISSUED BY ORDER OF THE COMMISSION.

This the 16th day of April, 2021.

NORTH CAROLINA UTILITIES COMMISSION

Kimberley A. Campbell

Kimberley A. Campbell, Chief Clerk

Commissioner ToNola D. Brown-Bland dissents in part.
Commissioner Daniel G. Clodfelter dissents in part.
Commissioner Floyd B. McKissick dissents in part and concurs in part

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

Commissioner ToNola D. Brown-Bland, dissenting in part:

I dissent from the Commission's decision to allow the Company to defer the capital costs of eight programs associated with GIP investments and to accept and approve the Second Partial Stipulation as it relates to said investments.

In my opinion, the majority decision on GIP cost deferral is contrary to the ratemaking standards of N.C. Gen. Stat. § 62-133. Use of deferral accounting is generally outside the traditional principles set forth in N.C.G.S. § 62-133(b) and (c), and therefore can only be allowed pursuant to N.C.G.S. § 62-133(d). However, the greater weight of the record evidence compels the determination that the cost items for which deferral is sought — and agreed upon by fewer than all parties of record — are not so unusual, extraordinary, or complex that the Company should be granted an exception to seek recovery of costs outside of the ordinary ratemaking standards established by the General Assembly; nor has the majority made any such finding. I cannot agree that the parties' settlement of this issue overrides or obviates the Commission's duty to make the determinations that are *required* before deferral accounting can be authorized under Chapter 62 of the North Carolina Utilities Act. *State ex rel. Utils. Comm'n v. Stein,* 375 N.C. 870, 926, 851 S.E.2d 237, 273 (2020).

In N.C.G.S. § 62-133(d), the legislature saw fit to provide both consumers of public utility service and public utilities with a "'safety valve'" which permits the Commission to consider facts outside of those prescribed by the ordinary ratemaking standards when those standards "prove inadequate" to allow the Commission to meet its obligation to set just and reasonable rates. *Id.* at 925-26, 851 S.E.2d at 272–73. Our Supreme Court recently clarified, however, that § 62-133(d), the safety valve, is to be relied upon over § 62-133(b) and (c) only "in extraordinary instances in which the traditional ratemaking standards set forth in N.C.G.S. § 62-133 are insufficient." *Id*. That is to say, N.C.G.S. § 62-133(d) is not to be exercised routinely.

To the contrary, "N.C.G.S. § 62-133(d) [does] not allow the Commission to . . . ignore the ordinary ratemaking standards set out elsewhere in N.C.G.S. § 62-133" where use of those principles allows for the establishment of just and reasonable rates. *Id.* at 926, 851 S.E.2d at 273. The "safety valve" is just that, and cannot be applied absent specific determinations of "unusual, extraordinary, or complex circumstances" unable to be addressed by traditional ratemaking standards. In relying on the safety valve, the Commission must reasonably conclude that such circumstances justify a departure from traditional standards, determine that the facts establishing those circumstances must be considered in order to set just and reasonable rates, and provide sufficient explanation as to why divergence from traditional standards is appropriate. *Id.* Such determinations and conclusions are decidedly absent from the majority decision.

In practice, the Commission has long applied virtually the same factors articulated by the Supreme Court in *Stein* before exercising its discretion pursuant to N.C.G.S.

§ 62 133(d) to allow public utilities to recover costs using deferral accounting. The Commission has repeatedly stated that deferral accounting is the exception to the general rule that costs should be recovered from ratepayers and applied to or matched with revenues received during the same time period the costs were incurred; is contrary to the rule; should be used sparingly; and is not favored as it provides for the future recovery of costs for utility services provided to ratepayers in the past. *See* Order Approving Deferral Accounting with Conditions, *Petition of Duke Energy Carolinas, LLC, for an Accounting Order to Defer Certain Environmental Compliance Costs and the Incremental Costs Incurred*, No. E-7, Sub 874, at 24–25 (N.C.U.C. Mar. 31, 2009).[1] As a result, the Commission consistently requires utilities requesting deferral treatment to make a clear and convincing showing that the costs proposed for deferral are of an unusual or an extraordinary nature or type and that, absent deferral, the requesting utility would experience a negative material impact on its financial condition. *Id.* This requirement ordinarily demands a showing that such costs represent significant, considerably complex, nonroutine investments that were unanticipated or beyond the utility's ability to control or plan for the timing of incurring the costs. *See* Order Granting Partial Rate Increase, *Application by Carolina Water Service, Inc. of North Carolina for Authority to Adjust and Increase Rates for Water and Sewer*, Docket No. W-354, Sub 364, at 42-43 (N.C.U.C. March 31, 2020). If the cost items sought to be deferred are not found to be unusual or extraordinary, such determination is dispositive and the materiality of the impact of the costs on the financial condition of the utility is not reached. *See* Order Approving Amended Schedule NS and Denying Deferral Accounting, *Application by Virginia Elec. & Power Co., d/b/a Dominion N.C. Power, for Approval of Amended Schedule NS*, No. E-22, Sub 517, at 11 (N.C.U.C. Mar. 29, 2016) (Sub 517 Order).

In this case, as in Duke Energy Carolina, LLC's (DEC) last two rate cases, the items proposed for deferral fail the unusual and extraordinary inquiry. In DEC's 2018 general rate case, it proposed to recover costs using deferral accounting for a modernization project it called Power Forward. I agree with Commissioner Clodfelter that GIP, as presented in both the instant case and DEC's 2020 general rate case, is primarily a subset, or a whittled down, more compact version, of Power Forward — in its scope, size, and costs.[2] The eight GIP programs that the Public Staff and DEP stipulate as

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[1] *See also* Order Approving Partial Settlement Agreement and Stipulation, Deciding Contested Issues, Granting Partial Rate Increase, and Requiring Customer Notice, *Application of Aqua North Carolina, Inc. to Adjust and Increase All rates for Water and Sewer Utility Service,* No. W-218, Sub 526, at 41–47, 136-37 (N.C.U.C. October 26, 2020); Order Allowing Deferral Accounting, *Transfer of Certificates of Pub. Convenience and Necessity and Ownership Interests in Generating Facilities from Duke Energy Carolinas, LLC, to Northbrook Carolina Hydro II, LLC, and Northbrook Tuxedo, LLC*, No. E-7, Sub 1181, at 16–18 (N.C.U.C. June 5, 2019); Order Approving Partial Settlement Agreement and Stipulation, Granting Partial Rate Increase, and Requiring Customer Notice, *Application by Aqua N.C., Inc., for Authority to Adjust and Increase Rates*, No. W-218, Sub 497, at 50 (N.C.U.C. Dec. 18, 2018); Order Approving Amended Schedule NS and Denying Deferral Accounting, *Application by Virginia Elec. & Power Co., d/b/a Dominion N.C. Power, for Approval of Amended Schedule NS*, No. E-22, Sub 517, at 11–12 (N.C.U.C. Mar. 29, 2016); Order Approving Deferred Accounting Treatment, *Request by Pub. Serv. Co. of N.C., Inc., for Deferred Accounting Treatment Related to Year 2000 Conversion Costs*, No. G-5, Sub 369, 3–4 (N.C.U.C. Apr. 29, 1997), *aff'd*, Order on Reconsideration (N.C.U.C. June 12, 1997).

[2] While DEP did not include Power Forward in its revenue requirements for the Sub 1142 proceeding, as part of its Sub 1142 testimony describing its own Power Forward initiative, DEP targeted

appropriate for deferral treatment are not at all extraordinary or unusual. Neither the GIP programs nor the reasons proffered for their need, as was the case with the programs in Power Forward, are unique or extraordinary to DEP or North Carolina. Rather the GIP programs are update, upgrade, and modernization programs, required of the Company to maintain the electrical distribution system and improve reliability, and are part of the routine, ordinary business of being a vertically integrated electricity provider. Without such programs the electric utility would not be providing quality service.

Further, these requirements are not new to the industry, and it cannot be said that the Company was unaware and unable to plan and time the recovery of the modernization projects approved by the Commission as part of GIP. Instead, a review of DEP's and its parent company's Annual Reports reveals that both the Company and its parent have been discussing and planning for grid modification initiatives for a long time. Unlike a catastrophic storm that develops with little notice or warning, the need for grid modification is such a routine circumstance that the Company has discussed and worked on related plans for over ten years. In 2010, the parent company discussed graduating its grid from analog to digital and adding two-way communications capabilities to its system to improve reliability and better serve customers. As early as 2007, DEP was already investing in its Distribution System Demand Response program (DSDR), an improvement to its distribution system allowing the utility to manage voltage on its entire distribution system. DSDR[3] will essentially be converted to become part of IVVC, one of the GIP programs approved in this docket by the majority for deferral, and it illustrates that such voltage control initiatives are not new. Well before the Power Forward and GIP proposals, voltage control projects like DSDR and IVVC had been considered part of the business of maintaining and operating a reliable, efficient electrical distribution system. Such projects have never been considered unusual or beyond the context of maintaining the grid to provide quality service. Thus, Commissioner Clodfelter is correct in noting that the Company has been investing in grid modification and some of the proposed GIP programs over several years further highlighting that this work is a regular part of the Company business and, more importantly, that traditional ratemaking procedures have been adequate. To this day, all decisions as to timing, pace, and amount of spending on grid modification have been largely within the Company's control — again, undermining any finding of extraordinary circumstances that might justify deferral accounting as a means of cost recovery for GIP.

I do not disagree with the proposition that GIP will provide benefits or that the Company's initial GIP proposal has been narrowed, focused, and vetted by stakeholders, including the Public Staff, who have worked together and invested time in coming to agreement and refining DEP's GIP proposals. I also believe that it is wise, given so much uncertainty around the cost estimates for GIP, that the Commission is limiting costs and

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that it intended to spend $1.6 billion in capital and $62.4 million in O&M from 2017 through 2021. *See* 2018 Tr. vol. 6, 59–60; 2018 Tr. vol. 9, 22.

[3] DSDR was approved by the Commission for DSM/EE rider cost recovery in 2009. Order Approving Program, *Petition of Progress Energy Carolinas, Inc. for Approval of Distribution System Demand Response Program,* Docket No. E-2, Sub 926, (N.C.U.C. June 15, 2009).

that the Public Staff will work with the Company to file reports and cost trackers on various details of GIP progress. Yet, none of these considerations establishes that GIP is extraordinary or unusual such that the Company should be allowed to depart from the ordinary ratemaking procedures in § 62-133. Unlike in cases concerning disputes and interests limited to private parties where settlements are generally favored, the Commission should refrain from treading down the path that could suggest that parties will be allowed through settlement to disregard law and clearly established Commission principles of regulation, especially where such settlements affect the public interest protected by the law and principles at issue as well as the interests of the non-settling parties.

It is my further opinion that parties in this proceeding have misconstrued the language in the Commission's opinion in the 2018 DEC Rate Order. There, the Commission stated the following:

> The Commission can authorize a test for approving a deferral within a general rate case with parameters different from those to be applied in other contexts. Consequently, with respect to demonstrated Power Forward costs incurred by DEC prior to the test year in its next case, the Commission authorizes expedited consideration, and to the extent permissible, reliance on leniency in imposing the "extraordinary expenditure" test.

2018 DEC Rate Order, at 149. This language does not signal any change to the Commission's historical test for deferral accounting; rather, it speaks to a realization that single-issue ratemaking concerns implicated by authorization of deferral accounting could be lessened by the full contemporaneous review of all costs and revenues that occurs as part of a general rate case. Therefore, the Commission suggested that it had the future option to revise or create a different deferral test for a deferral request made and considered as part of a general rate case. No such change was made in that Order and no such change has been made by this Commission since that time. The test remains unchanged and continues to require a finding of extraordinary and unusual circumstances in order to approve deferral accounting such as requested for GIP. Indeed, given the *Stein* decision it is not clear that the Commission *could* craft any test changing or eliminating the extraordinary and unusual requirement even if it wants.

Moreover, the second sentence in the passage above relates to a deferral request made outside a general rate case. It is not meant to convey the demise of the primary focus of the historical deferral test, *i.e.*, the extraordinary and unusual circumstance. *See also* Sub 517 Order, at 11 (explaining that the unusual or extraordinary determination is the primary hurdle for deferral approval). Rather, it addresses the secondary materiality/magnitude aspect of the test in the event that the utility was to seek deferral prior to, and outside of, a general rate case. In that circumstance, the referenced leniency was to be directed to the "extraordinary *expenditure"* threshold only — not directed to the extraordinary or unusual circumstance aspect of the test, which is required by the Supreme Court in *Stein* for the exercise of the Commission's authority pursuant to § 62-133(d).

Finally, like all utilities whose rates for service are set by the Commission, DEP abhors regulatory lag and has from time to time made attempts to eliminate or reduce it by use of the deferral mechanism. However, some lag is an inherent part of the statutory ratemaking process in North Carolina — and has been for decades. While regulatory lag in rates offers some positive aspects to customers – e.g., serving as incentive for cost effective and efficient management of the utility and also serving as a guard against waste and inefficiency — it is understandable that utilities see it as a challenge. If regulatory lag is indeed the driving force behind the request for deferral treatment of GIP costs, the appropriate solution is legislative relief. The Commission should not strain the bounds of its authority to exercise use of a deferral mechanism where the legislature did not intend it to be used.

For these reasons I respectfully dissent.

/s/ Commissioner ToNola D. Brown-Bland
Commissioner ToNola D. Brown-Bland

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

Commissioner Daniel G. Clodfelter, dissenting in part:

I differ from the Commission Opinion on three points and therefore write separately to explain my reasons for doing so.[1]

I. Deferral of Grid Improvement Plan Capital Costs

Deferral accounting is an exception to the basic principle embodied in N.C.G.S. § 62-133 that costs are to be allocated and charged to the revenues received in the period during which expenditures were incurred. *State ex rel. Utilities Commission v. Edmisten,* 291 N.C. 451, 468-70, 232 S.E.2d 184, 194-96; *State ex rel. Utils. Comm'n v. Stein*, 375 N.C. 870, 921, 851 S.E.2d 237, 269-70 (2020) (*Stein*).

For this reason the Commission has established a clear standard for granting deferral accounting treatment. I believe the Commission addresses this standard only in the most cursory fashion and does not properly consider its application to this case. The discussion of the standard for deferral accounting in the Commission's opinion at page 140 is limited to noting that in the Sub 1146 Order the Commission stated that deferral accounting could be granted under different parameters in a general rate case than when the request was made outside a general rate case. But neither the Sub 1146 Order nor the Commission's order in this case attempt to articulate what those "different parameters" are or might be or under what circumstances a departure from the generally prevailing standard is warranted. Moreover, as noted elsewhere in this dissent, the Commission has regularly applied its established test for deferral accounting *in general rate cases,* including in Docket No. E-7, Sub 1146 and the other Commission decisions cited and quoted in this dissent. I find the Commission's treatment of the matter in this case to be essentially standardless.

As recently as its March 31, 2020 Order Granting Partial Rate Increase and Requiring Customer Notice in Docket No. W-354, Sub 363 (CWSNC Order) the Commission reiterated that deferral accounting should be used sparingly and as an exception to the general rule 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 a utility's rates and charges. Paraphrasing from the CWSNC Order, deferral is not favored in part because it provides for the future recovery of costs for utility services that were provided to ratepayers in the past. The Commission has found that an exception can be made when reasonable and prudently incurred costs are unusual or extraordinary, in some instances because they were unexpected, and when they are of a magnitude that would result in a material impact on the utility's financial

[1] This dissent follows and relies on the same analysis and discussion as my dissent in Docket No. E-7, Sub 1214. Rather than require a reader to switch back and forth between text in that docket and in this one I have chosen to repeat and restate the same text here, modified of course where there are differences between the facts in the two dockets.

position in the absence of an ability to recover those costs from revenues in future periods. In applying this test the Commission has disfavored deferral treatment for expenditures that are planned or whose timing and amount are under the control of the utility. In this instance the record is clear that the costs for which deferral accounting treatment is requested are among a larger group of ongoing programs to modernize and upgrade DEP's transmission and distribution systems, many that commenced well before deferral accounting was requested in this case, all completely under the Company's control, and, none that, singly or in combination, present any significant threat to the utility's financial condition or its ability to earn its allowed rate of return.

Because deferral accounting is a departure from the basic ratemaking structure set forth in N.C.G.S. § 62-133(a)-(c), one must consider the Supreme Court's recent discussion in *Stein*. There the Court set forth four factors governing the Commission's reliance upon its authority under N.C.G.S. § 62-133(d) to supplement, modify, or depart from the basic ratemaking structure established in §§ 62-133(a)-(c). The four factors identified by the Court in its opinion are essentially a restatement of the Commission's traditional two-prong test for accounting deferrals:

> [W]e hold that the Commission may employ N.C.G.S. § 62-133(d) in situations involving (1) unusual, extraordinary, or complex circumstances that are not adequately addressed in the traditional ratemaking procedures set out in N.C.G.S. § 62-133; (2) in which the Commission reasonably concludes that these circumstances justify a departure from the ordinary ratemaking standards set out in N.C.G.S. § 62-133; (3) determines that a consideration of these "other facts" is necessary to allow the Commission to fix rates that are just and reasonable to both the utility and its customers; and (4) makes sufficient findings of fact and conclusions of law supported by substantial evidence in light of the whole record explaining why a divergence from the usual ratemaking standards would be appropriate and why the approach that the Commission has adopted would be just and reasonable to both utilities and their customers.

Stein, 375 N.C. at 926,851 S.E.2d at 273.

The record in this case plainly establishes that DEP does not need accounting deferral treatment to enable it to undertake and move ahead with its grid improvement initiatives (the Grid Improvement Plan or, sometimes, GIP). Public Staff witnesses testified that at the time of this general rate case and without any inducement or protection under a deferral accounting order the Company had already commenced work on thirteen of the GIP programs, that it spent about $38 million on those programs during 2018, and that it had spent another $164 million during 2019.[2] Tr. vol. 57, 378. During the update period of March through May 2020, DEP completed and placed in service another

[2] Except where otherwise noted, all figures are on a total system basis.

$52.8 million of investments in the various GIP programs.[3] Tr. vol. 16, 61. In fact DEP's own evidence was that spending on the self-optimizing grid program was outpacing its staff's ability to implement attendant computer programming changes needed to enable complete functionality of those investments, leading to delays in full implementation of some of the system upgrades. Tr. vol. 16 217-*8; see also* Commission Opinion at 135*.* Given these facts I am compelled to conclude that the GIP investments are quite far from being extraordinary, unusual, or unanticipated; they are instead well-thought out, planned, and executed upgrades and improvements to enhance the performance and the reliability of the Company's transmission and distribution systems. Maintaining, protecting, adapting, and enhancing reliability and performance of the electric grid are core obligations of any electric utility.

The Company contends that each of these investments, and those it wishes to make in the future, are necessary and indeed essential to respond to changes and challenges arising from such things as the deployment of distributed generation and other new grid-edge technologies and from increasing security concerns about cyberattacks on businesses and infrastructure such as the electrical grid. The fact that these improvements may be sound and even necessary does not, however, meet the Commission's standard for deferral treatment. The Company attempted to distinguish its GIP investments from other ongoing spending to upgrade equipment and facilities with newer, more efficient and effective replacements by relying on seven so-called "megatrends." These megatrends, however, are nothing more than general features of North Carolina's evolving demography and economy or else they arise from technological innovations that are affecting many sectors of modern life and do not uniquely affect the electric power industry. They have been at work for many years and are neither accidental, sudden, nor unforeseen. The difficulty with using these megatrends to justify special ratemaking treatment for the Company's GIP spending is that the argument simply proves far too much. Virtually every aspect of the Company's traditional model is being affected in some way by one or more of these megatrends. If the megatrends justify special ratemaking treatment for the eight specific GIP programs singled out in the Second Partial Stipulation, then they could justify similar treatment for all other portions of the Grid Improvement Plan and, for that matter, virtually every new investment the Company wishes to undertake.

Rather than being extraordinary or unusual I would find DEP's GIP programs to be more analogous to the automated meter reading (AMR) installations for which Carolina Water Service of North Carolina (CWSNC) sought deferral accounting in Docket No. W-354, Sub 364. Both involve the deployment of new technologies that promise substantial efficiencies and new capabilities for the utilities and resulting benefits for customers. In the CWSNC Order the Commission found that CWSNC's meter replacements had been on-going for several years and were anticipated to extend several more years into the future. In that case as in this one, the utility requested deferral

[3] This total of approximately $255 million spent over a period of approximately two and one-half years *without* the benefit of any deferral accounting treatment should be compared to the approximately $400 in GIP program expenditures over the two and one-half years from June 2020 through December 2022 for which the Commission finds deferral treatment to be necessary and appropriate.

accounting to mitigate the effect of regulatory lag on earned returns. The Commission rejected CWSNC's request, noting that the timing of meter replacements was entirely within the control of the Company. The fact that CWSNC's AMR investments spanned many years contributed to the Commission's determination that the investments were part of the regular business of adapting and updating the utility's systems to meet the most up-to-date standards and technologies. The fact that CWSNC sought to adopt a new technology and realize significant system benefits enabled by that new technology did not suffice to justify deferral accounting treatment. The DEP investments presently before the Commission also span many years, some programs starting as early as 2018 and some extending beyond 2022, based on DEP's cost-benefit analyses.[4] Several of them, such as the replacement of oil-filled hydraulic reclosers with remotely operated digital reclosing devices, the replacement of single-use fuses with automated reset fuses, and the replacement of electromechanical relays with remotely operated digital relays are virtually indistinguishable in substance from CWSNC's replacement of manually read water meters with AMR meters.[5]

In this instance several parties who support the Company's deferral accounting request, notably the Public staff, rely heavily, in fact almost entirely, on inferences they draw from the Commission's Sub 1146 Order. In that case DEC petitioned for creation of an annual revenue rider, or alternatively, to obtain deferral accounting treatment for a set of grid modernization programs it then referred to as Power Forward.[6] In its Sub 1146 Order the Commission found that DEC failed to show that Power Forward costs qualified for deferral accounting treatment. The Sub 1146 Order stated:

> [T]he Commission finds that DEC has not satisfied the criteria for deferral accounting. In order for the Commission to grant a request for deferral accounting treatment, the utility first must show that the cost items at issue are adequately extraordinary, in both type of expenditure and in magnitude,

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[4] Indeed, the Company's existing DSDR assets and functionality, which will be converted to operate in conservation mode at an estimated cost of approximately $10 million, were put into service several years prior to 2018, and the Company is already recovering the costs of the DSDR system through its DSM/EE rider. I am just not persuaded that the Company requires the benefits of accounting deferral treatment in order to make this conversion of an existing system to operate in a different modality.

[5] One of the eight GIP programs included in the Second Partial Stipulation involves cybersecurity. As the Commission's opinion notes, DEP witness Oliver testified that these elements of the GIP are essentially the same as those DEP has been funding in the past, only the amount of spending will be increased. Consolidated Tr. vol. 5, 39. As to those programs I also note that the Company has obtained an order from FERC permitting it to aggregate its expenditures into a single composite project eligible for AFUDC treatment, thereby allowing the Company to continue to accrue AFUDC until the last component element of its cybersecurity project is placed into service. FERC Docket No. AC19-75 (Dec. 19, 2019). It is not at all clear how this treatment relates to the deferral accounting treatment requested in this case or why if AFUDC treatment is available for these cybersecurity programs there would be any need for deferral accounting treatment for the cybersecurity programs at all.

[6] The specific programs for which deferral accounting treatment is sought in this case is a subset of the larger set of what DEP refers to as its Grid Improvement Plan, which in turn is itself a substantially modified version — both in scope and magnitude and as to its elements — of DEP's and DEC's earlier Power Forward initiative.

> to be considered for deferral. Second, the utility has to show that the effect of not deferring such cost items would significantly affect the utility's earned returns on common equity. Although it was uncontested by any party that DEC's planned Power Forward spend is extraordinary in magnitude, the Commission is unpersuaded that the entirety of Power Forward programs as proposed are unique or extraordinary. Assuming arguendo that all Power Forward programs as proposed were found to be unique and extraordinary, thus meeting the threshold criteria for consideration of deferral accounting, DEC failed to show that the effect of not deferring Power Forward costs would significantly affect its earned returns on common equity.

Sub 1146 Order, at 148.

The Commission further directed DEC to collaborate with stakeholders to address the myriad issues that had been raised about Power Forward in that rate case and also stated:

> The Commission can authorize a test for approving a deferral within a general rate case with parameters different from those to be applied in other contexts. Consequently, *with respect to demonstrated Power Forward costs incurred by DEC prior to the test year in its next case*, the Commission authorizes expedited consideration, and *to the extent permissible*, reliance on leniency in imposing the "extraordinary expenditure" test.

Id., at 149 (emphasis added).

Public Staff witness Maness interpreted the Sub 1146 Order to mean that the Commission is prepared to show leniency as to the financial impact of the Company's request in the instant rate case.[7] That interpretation was not the Commission's intent and it does not comport with the actual language used by the Commission. Rather, the quoted language from the Sub 1146 Order refers to a scenario that did not occur, one in which DEC incurred grid modernization costs before the test year in the current case and requested deferral treatment for those costs in the interim period and outside the parameters of a general rate case. Had that occurred, the Commission was prepared to consider the request in an expedited fashion, outside a general rate case, and was prepared to be lenient in imposing the extraordinary expenditure test, especially if DEC's collaboration with the parties had produced consensus as to the programs whose costs would be deferred. That is simply not the situation now presented to the Commission.

[7] Strictly speaking, the so-called "leniency" language in the Commission's Sub 1146 Order applies to DEC only and not to DEP. No similar language was included in DEP's last general rate case order in Docket No. E-2, Sub 1142. All parties have, however, simply assumed that the Commission's language in the Sub 1146 Order should be treated as equally applicable to DEP. In its order in Docket No. E-2, Sub 1142, the Commission was silent on the matter of the future ratemaking treatment of expenditures on programs such as Power Forward or GIP.

Moreover, the language from the Sub 1146 Order relied upon by the Public Staff was directed to the first prong of the Commission's deferral accounting standard – that the expenditures be unusual or extraordinary in type and magnitude – and not to the second prong of that standard. On that issue the pertinent language from the Sub 1146 Order is the following:

> With respect to deferral, the Commission acknowledges that, irrespective of its determination not to defer specific costs in this case, the Company may seek deferral at a later time outside of the general rate case test year context to preserve the Company's opportunity to recover costs, to the extent not incurred during a test period. In that regard, were the Company in the future before filing its next rate case to request a deferral outside a test year *and meet the test of economic harm,* the Commission is willing to entertain a requested deferral for Power Forward, as opposed to customary spend, costs.

Id. (emphasis added).

In his direct testimony Public Staff witness Maness stated that the Public Staff would not object if the Commission determined that the ROE impacts from a narrower set of GIP programs fall within the range of leniency that the Commission intended in the Sub 1146 Order. Tr. vol. 15, 1600-01. Strikingly, however, in response to questions from Commissioner Brown-Bland, witness Maness confessed that absent the quoted language from the Sub 1146 Order he could not conclude that the GIP investments proposed for deferral treatment in the Second Partial Stipulation would meet the second, financial impact prong of the Commission's standard. Consolidated Tr. vol. 7, 32; *see also* Commission Opinion at 122.[8] The GIP programs included in the Second Partial Stipulation are very dramatically scaled back from the group of programs that constituted the original Power Forward initiative. If, as the Commission found in the Sub 1146 Order, the multi-billion dollars of proposed Power Forward spending was insufficient to affect in a significant way the utility's potential to earn its authorized return on common equity, then I cannot conceive how a contrary finding could be supported as to the GIP programs covered in the Second Partial Stipulation based on the evidence in this proceeding. Moreover, the Company's own witnesses explained that in the absence of deferral accounting treatment, the Company had other ways to manage the financial impact of the proposed GIP expenditures. DEP witness Oliver confirmed that if the Commission did not grant deferral accounting treatment for the proposed GIP programs, the Company nevertheless would continue to implement them, managing and adjusting to

[8] Even if the Sub 1146 Order were interpreted such that "leniency" is taken to refer to both prongs of the deferral standard, not just the "extraordinary expenditure" prong, it should be noted that the Commission qualified leniency with the phrase "to the extent permissible." The outer boundaries of what is "permissible" are not, and likely could not be, established with certainty. But a virtual abandonment of the requirement that the utility show substantial financial harm is not, I think, within those boundaries. In this regard I note that N.C.G.S. § 62-133(b)(1)a authorizes the Commission to approve inclusion of construction work in progress in rate base, a mechanism to address regulatory lag similar in some ways to deferral accounting, when the Commission finds such use to be in the public interest "and necessary to the financial stability of the utility in question."

accommodate available resources and timetables in order to do so. Consolidated Tr. vol. 6, 56.

Leaving aside the Commission's two-prong test for deferral treatment and the Supreme Court's *Stein* factors defining the Commission's authority to depart from traditional ratemaking principles, there are other features of the Second Partial Stipulation's provisions dealing with GIP programs that I find unsettling. One involves what exactly it is that the parties are asking from the Commission. Deferral accounting treatment for expenditures made in connection with specific GIP programs is certainly being sought, but there is also something more. During the consolidated portion of the hearing DEC witness Jane McManeus testified that it is important for the Commission to make clear that the Commission believes the GIP programs are appropriate undertakings and that the costs of such program can ultimately be recovered from customers, assuming they are found to be reasonable in amount. Consolidated Tr. vol. 9, 24. DEP witness Kim Smith testified that she agreed with witness McManeus. *Id.* at 33. To that end the Second Partial Stipulation contains the following paragraph:

> The Stipulating Parties' agreement regarding deferral treatment of GIP costs constitutes only approval of the decision to incur GIP program costs. The Public Staff reserves the right to review costs for reasonableness and prudence.

Second Partial Stipulation § Ill.D.

Under questioning from Commissioners neither the Company nor the Public Staff witnesses were able to give completely clear meaning to this provision, seeming to contend that acceptance of this provision commits the Commission to allowing cost recovery for GIP program expenditures in future rate cases while at the same time preserving the Commission's full review of GIP spending under the traditional "prudence" standard. As I interpret it, the Company is seeking prior Commission approval of a list of loosely related programs, a practice this Commission seldom follows outside certificate of public convenience and necessity proceedings.[9] Some of those programs involve primarily operational and business process changes, such as the Integrated Systems Operations Plan, while others involve investments in new hardware and physical infrastructure. The Company did not articulate any set of unifying principles – aside from referring to the so-called "megatrends" – that bring these disparate programs into a single integrated whole. The proposed bifurcated review, which is what I believe the quoted provision is attempting to accomplish, deprives the Commission of the ability at the time when all costs have been incurred and all benefits have been have realized to judge whether or not the investment was warranted in the first instance. Although the Second Partial Stipulation contemplates ongoing review of GIP program spending by the Public

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[9] Indeed, as to those elements of the GIP that involve investment in utility plant and equipment, as opposed to expenditures made on such things as planning, operational design and operating management of the grid, if those investments are indeed so extraordinary and unusual as is contended, one may well ask why they are not subject to the certificate of public convenience and necessity requirement set forth in N.C.G.S. § 62-110(a), which requires a certificate before construction or operation of "any public utility plant or system," except where such construction or operation occurs in the "ordinary course of business."

Staff, it does not set forth any clear or measurable performance goals or targets that must be met in order ultimately for cost recovery to be allowed. According to the Second Partial Stipulation the Public Staff's review will include an evaluation of actual benefits realized compared to anticipated or expected benefits. What will be the way forward if the Public Staff should conclude that expected benefits failed to materialize in any significant degree or were wholly or very largely offset by unexpected or additional costs? In such a case will the quoted provision from the Second Partial Stipulation permit or not permit the determination that cost recovery should be denied altogether? Unlike a majority of the Commission, I do not believe that an aggregate spending cap on the amount of expenditures for which deferral treatment is allowed adequately substitutes for clear and measurable performance goals or targets that must be met in order for cost recovery to be allowed.[10]

A second unsettling feature of the Second Partial Stipulation's treatment of the GIP programs involves the increasing tendency for regulated utilities to attempt to string together a series of small-scale investments in order to craft some composite whole that can be offered up for deferral accounting treatment. The evolution first from Power Forward, then to the Grid Improvement Plan, then to a series of multiple, only partially overlapping, settlements between DEP and various individual parties to this proceeding about which GIP programs those parties would support, finally culminating in the Second Partial Stipulation with the Public Staff is a good illustration of the potential problems with this approach to solve the problem of regulatory lag.

In a recent general rate case involving Aqua North Carolina, Inc. (Aqua), Public Staff witnesses expressed reservations about a deferral accounting request that involved the aggregation of many unrelated projects. *See* Joint Testimony of Windley E. Henry and Charles M. Junes dated May 26, 2020, in Docket No. W-218, Sub 526. These witnesses testified that Aqua's deferral request was based on "the novel argument that the projects and related costs for which it seeks deferral accounting treatment should be considered not on an individual basis, but in the aggregate." I believe the same could be said of DEP's GIP request in this case. I am concerned with the large number and variety of programs that DEP has included under the GIP umbrella, with cost estimates that could vary by as much as 30 percent, and that contains many investment types that overlap with customary maintenance, repair, and upgrade expenditures. It will, I believe, become increasingly difficult for the Commission to apply the "extraordinary" or "unusual" prong of its established deferral accounting standard with any degree of integrity or consistency if this practice of aggregating small programs and expenditures becomes well established, especially if, as occurred in this case, that aggregate is arrived at by a process of negotiation and settlement among contending stakeholders.

A third feature that gives me pause concerns the future rate impacts of the Commission's approval of the Second Partial Stipulation. It is true that the decision to

[10] The "loose approval" treatment afforded here for the proposed GIP programs can be contrasted with the carefully structured provisions in N.C.G.S. § 62-110.1 governing certificates of public convenience and necessity for new generating facilities, which include several clauses authorizing the Commission to modify, revoke, or cancel a previously granted CPCN.

approve deferral accounting treatment for the GIP program expenditures included in the Second Partial Stipulation has no impact on the rates established in the present case. I cannot ignore, however, the implications of this request for future rate cases. The Company supports its case for the GIP investments by offering cost-benefit analyses that, the Company contends, show strong positive economic benefits from those investments. These analyses covered only some components and subprograms within the larger GIP effort, and they were strongly criticized by several intervenor witnesses as being based on studies or data that were out-of-date, were not well-tailored to the demographics and economy of North Carolina, or were otherwise deficient or flawed in various respects. Even if all those criticisms are valid, it nonetheless remains true that the Company and the contending intervenor adversaries did not disagree on either the directionality or the order of magnitude of one unmistakable feature of the Company's cost-benefit studies. The economic benefits disclosed by those studies center on improvements to service reliability, and they overwhelmingly flow to the benefit of the industrial and commercial customer classes. *See* Commission Opinion at 134*.* Yet based on the Company's analysis filed in this case the revenue requirement and resulting rate impact from the GIP programs will fall most heavily on the residential customer class. *See* Commission Opinion at 122*.* For me this is an important point.[11]

Witnesses for the Company and supporters of the GIP contended that the Commission should keep separate the present question, which is whether to grant permission to proceed with the GIP investments and grant deferral accounting treatment, from the question in future rate cases concerning how GIP program costs should be assigned to the different customer classes and, accordingly, reflected in rates. In the face of the extensive evidence presented in this case concerning problems of affordability of electric service, especially for low-income and unemployed North Carolinians and for many small businesses bearing the burden of a year of COVID-19 disruptions, I simply cannot perform this feat. If complications concerning the differential future rate impacts on different customer classes are staring at us from the end of the road, I am not comfortable pre-approving the GIP programs and granting them special ratemaking treatment without fully considering how the Commission will manage those complications when they materialize in future rate cases. The better approach would be to evaluate actual GIP expenditures made by the Company and actual results achieved for customers in the context of all other issues and decisions that culminate in the setting of just and reasonable rates in a future general rate case. While the Commission's decision to place a cap on the total GIP expenditures eligible for accounting deferral is a useful step, it is an inadequate substitute for the kinds of tools the Commission must have in order to

[11] Certain witnesses contended that it is not appropriate to consider the proportionality of the assignment of costs relative to the realization of benefits among the various rate classes. I commend to those witnesses Part I, Chapter 5 of Professor Bonbright's treatise, *Principles of Public Utility Regulation* (1960), where he discusses the use of the concepts of "value" and "benefit" in ratemaking. Summarizing the different theories and ways in which those concepts come into play, he observes" "…[I]n actual rate cases the cost [of service] principle is always given modified interpretation which, while not converting it into a value principle, takes indirect account of the effectiveness of the cost incurrence in contributing to the benefit of the consumers." *Id.* at 91.

properly grant pre-approval of the kinds of forward-looking expenditures such as the Company's proposed GIP investments.

Although in the end I dissent from the Commission's decision to grant deferral accounting treatment for elements of the proposed GIP, I am nonetheless conflicted about doing so. Increasingly, our present statutes governing ratemaking are proving to be poorly suited to address the types of investments that utilities are making and must continue to make in order to transition the electricity grid to the new world of distributed generation from renewables, non-wires solutions to grid reliability and capacity issues, and the two-way power flows that result from these first two trends, not to mention looming electrification of the transportation and real estate sectors and new challenges to grid reliability and resiliency due to cyberattacks and severe weather events. The fundamental paradigm by which rates are derived from examination of historic expenditures was adequate for a time when the electricity system was more stable and when major capital investments were largely centered on the addition of new centralized generating plants built to accommodate increases in aggregate system load. That paradigm does not work well now.

Even under the traditional ratemaking paradigm the General Assembly has shown an understanding of the need for tools that would enable what I would call "forward-looking" or, alternatively, "rapid response" ratemaking treatment in instances involving major capital expenditures or concerns about regulatory lag. In 2013 the General Assembly enacted N.C.G.S. § 62-133.12 to alleviate the effects of regulatory lag by allowing for recovery outside a general rate case of some portion of incremental depreciation expense and capital costs for eligible water and wastewater infrastructure projects that are placed into service between general rate cases. I believe the same recognition underpins N.C.G.S. § §62-133(b)(1)a and (b)(1)b, which establish the Commission's authority, under the circumstances and conditions spelled out in those statutes, to include in rate base construction work in progress, and also N.C.G.S. § 62- 110.7, which governs advance review and approval of nuclear power plant development. To date, however, for investments of the type exemplified by the GIP programs, no such special statutory treatment has been enacted, and thus the Commission is left to operate within the limits established by N.C.G.S. § 62-133(a)-(c), supplemented by § 62-133(d) as interpreted by the Supreme Court in *Stein.*

I wholeheartedly support efforts to change the existing ratemaking paradigm embodied in Chapter 62, and I was encouraged by the progress made in the consideration of SB 559 in the 2019-2020 session of the General Assembly. Though that legislation ultimately was not enacted, it will not be the last such effort. Recommendations coming from stakeholder working groups convened to flesh out the Clean Energy Plan developed in response to Executive Order 80 contain a number of options and possible changes to the General Statutes that could, if adopted, enable the Commission better to manage approval, oversight, and cost recovery for initiatives such as DEP's Grid Improvement

Plan.[12] Unfortunately, though, for now we must decide proceedings before us following the statutes we have. The Commission's decision is ultimately based not on substantial evidence that is material and sufficient under current law and precedent but instead on a wish and a hope – a wish that the Commission had the kind of authority I believe is essential for the future and a hope that the General Assembly will, even if after the fact as far as the present proceeding goes, take action that validates the policy rationale for the decision in this case. I share both that wish and hope, but I am constrained by the tools that we have been given by the General Assembly until they are changed.

I differ from the majority in that I do not believe a partial settlement of disputed issues, even more so an agreement by fewer than all parties and in circumstances where different settling parties agree on different provisions for settlement, can substitute for the Commission's lack of authority to engage in "forward looking" ratemaking, or that it can override or displace the Commission's existing standard for deferral accounting treatment, or that it can rectify the deficiencies in the evidence submitted to the Commission under its traditional test for an accounting deferral order. While settlements are certainly to be encouraged, I believe the Commissions' deference to the Second Partial Stipulation in this instance fails to comply with the requirement that the Commission exercise its own independent judgment with respect to the matters embraced in the settlement. This is especially troubling in that the settlement overrides a Commission standard that is to be used sparingly and whose use is to be considered an exception to general ratemaking principles. If litigating parties come to know and understand that by a settlement they can circumvent the Commission's standard, then what will be left of the notions of "sparingly" or "exceptional"? With respect to the Commission's decision granting deferral accounting treatment for certain of the Company's GIP expenditures I must therefore respectfully dissent.

II. Coal Ash Disposal and Groundwater Remediation Costs

Though I endorse much of the Commission's discussion of the proposed settlement relating to coal ash disposal and remediation costs, I cannot go the full distance. Pending before the Commission now are two matters only – first, a decision establishing rates in this proceeding and second, a decision on remand from the Supreme Court in Docket No. E-2, Sub 1142. I agree with the Commission majority that those portions of the CCR Settlement that address the two pending matters are appropriate and would produce rates that are fair and reasonable to the Company and to ratepayers. In arriving at this conclusion I have relied on the combined effect of the settlement of the case on remand and the settlement of the current proceeding. Considering them separately and individually, however, I would not reach the same result. For reasons discussed in my dissenting opinion in Docket No. E-2, Sub 1142 I do not consider the result in that case to be one that yielded just and reasonable rates, and the proposed CCR Settlement would reaffirm and leave unchanged that result. At the same time, however, the CCR Settlement would impose a greater reduction in the cost recovery

[12] See North Carolina Energy Regulatory Process – In Fulfillment of the North Carolina Clean Energy Plan B-1 Recommendation, December 22, 2020 Summary Report and Compilation of Outputs (https://files.nc.gov/ncdeq/climate-change/clean-energy-plan/2020-NERP-Final-Report.pdf).

request for ash basin closure and groundwater remediation expenditures in this case than I was prepared to impose, based upon the evidence offered in this case and the specific facts concerning the particular expenditures for which cost recovery is sought in this case. Because the combined effect of the settlement in this case and the settlement of the case on remand in Docket No. E-2, Sub 1142 closely approximates, for both the Company and for ratepayers, the combined result I would have reached, I support the CCR Settlement as to the two matters now before the Commission for disposition.

I am unclear as to exactly what position the Commission is taking with respect to the forward-looking provisions of the CCR Settlement. *See* Commission Opinion, Findings of Fact 20, 21, and 23. Aside from authorizing the Company to continue to defer ash basin closure and remediation expenditures in the same manner as was approved for the costs in this case and those in Docket No. E-2, Sub 1142, at this point I would take no position on those portions of the CCR Settlement that speak to the treatment of ash basin closure and groundwater remediation costs in future general rate cases. Those matters are not now at issue and thus are not before the Commission. Whether the financial terms the settling parties propose be applied to cost recovery requests in future rate cases will produce just and reasonable rates is, I believe, a question that can only be decided when the Commission has before it all the facts and circumstances of those future cases.

Finally, while I join in the Commission's directive, *see* Commission Opinion at 68-69, that the Company consider in its next general rate case the option of including in base rates a normalized allowance for ongoing coal ash expenditures, I would also have been prepared to go further and adopt such a cost recovery mechanism in the present case for all or some of the company's ongoing costs. When this mechanism was first suggested by the Company's affiliate, Duke Energy Carolinas, in its general rate case in Docket No. E-7, Sub 1146, it was rejected by the Commission. Two fundamental developments since that time have made the option viable and even, in my view, preferable to what the Commission and the parties have called the "spend-defer-recover" method employed to date. First, the Company's settlement with the Department of Environmental Quality means that from this point the nature and scope of the tasks that the Company will be required to perform in order to close the remaining ash impoundments and remediate detected groundwater contamination are no longer subject to regulatory uncertainty and litigation. They can be predicted and planned with a much greater degree of accuracy than was possible in 2017. Second, the Company has now substantially completed or is well advanced toward completing impoundment dewatering, ash excavation and other closure activities at its Sutton and Asheville facilities and has thereby gained valuable experience in forecasting the costs it may reasonably expect to incur to perform various closure activities. Because this cost recovery option would provide the Company consistent, predictable current cash flow to fund impoundment closure activities, not requiring it to tap its credit facilities or use shareholder capital, and because it would do so at lower cost to ratepayers, I believe it to be the superior method for achieving just and reasonable rates.

III. Cost Allocation Matters

Briefly, I note that my views on the appropriateness of using the single coincident peak method for allocating among customer classes the demand portion of production costs and of using the minimum system method for allocating a portion of distribution system costs on a per customer basis remain unchanged from my dissents in Docket Nos. E-2, Sub 1142 and E-7, Sub 1146. I believe these two cost allocation methodologies are flawed, and in the case of the so-called “minimum system” method they are increasingly being abandoned by regulatory commissions in favor of the “basic customer charge” method. In this case the Company was unable to produce any new, different, or more persuasive reasons for me to reconsider my prior positions. I am, however, hopeful that the two stakeholder forums initiated by the Commission’s decision in this case, one intended to take a comprehensive review of matters of rate design and the other dealing with problems of affordability, will permit a more extensive debate about how these flawed cost allocation methods help drive many of the problems that exist in current customer classifications and class rate designs and with respect to the affordability of service for low-income residential customers.

For the foregoing reasons and with respect to the issues discussed in this opinion, I dissent.

/s/ Commissioner Daniel G. Clodfelter
Commissioner Daniel G. Clodfelter

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

Commissioner Floyd B. McKissick, Jr., dissenting in part, and concurring, with an explanation:

Deferral of Grid Modernization Expenses

The majority has accepted the Second Partial Stipulation as it relates to eight separate projects which they are now collectively referring to as being part of a Grid Modernization Program. I must dissent on this issue. In my opinion, these projects fail to satisfy the four factors identified by the Supreme Court in *Stein*, which are substantially the same as the two-pronged test historically applied by the Commission for accounting deferrals. The Commission's acceptance of the Second Partial Stipulation in light of these circumstances has the potential to incentivize applicants in future cases where deferral treatment is sought to use the give and take of compromise to seek the deferral treatment of projects which would not otherwise meet or satisfy standards of the court or of this Commission. In addition, the Company commenced substantial work pursuant to its Grid Modernization Program before it sought deferral accounting treatment in this proceeding, and testimony provided by the Company's witnesses during the hearing clearly and unambiguously expressed an intent on the Company's behalf to carry out its Grid Modernization Program regardless of whether deferral accounting treatment was granted by the Commission in this proceeding.

Coal Ash Disposal

Concurrence with Explanation

After conducting a critical review of the CCR Settlement, I am persuaded that the give and take of the compromise process has resulted in an agreement between the parties to the stipulation, those parties being DEP, the Public Staff, the North Carolina Attorney General's Office, and the Sierra Club, to the issues set forth and agreed upon in the CCR Settlement. It is I believe uncontroverted, but nonetheless worth stating, that this agreement cannot legally bind other parties or intervenors in the future through the year 2030 that were not parties to the agreement. Therefore, intervenors in the future that were not parties to the CCR Settlement would be free to raise issues or contentions they deem relevant and appropriate relating to these issues. Likewise, future Commissions would have a duty and responsibility to hear and receive evidence on the issues at an appropriate time, including evidence relating to the issues agreed upon by the stipulating parties in the CCR Settlement. This includes issues related to the treatment of coal ash basin closures and remediation cost in future general rate cases.

As noted in the Commission's Order, the CCR Settlement does not involve a contemporaneous cost recovery mechanism which could be of substantial benefit to ratepayers as well as to DEP. I am of the opinion that a properly structured cost recovery mechanism would be far preferable to the "spend-defer-recover" method in the CCR Settlement Agreement.

/s/ Commissioner Floyd B. McKissick, Jr.
Commissioner Floyd B. McKissick, Jr.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-22, SUB 532

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Virginia Electric & Power Company, d/b/a Dominion North Carolina Power, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	)))))	ORDER APPROVING RATE INCREASE AND COST DEFERRALS AND REVISING PJM REGULATORY CONDITIONS

HEARD: Wednesday, August 17, 2016, at 7:00 p.m., Halifax County Historic Courthouse, 10 N. King Street, Halifax, North Carolina

Tuesday, September 13, 2016, at 7:00 p.m., Pasquotank County Courthouse, 206 E. Main Street, Courtroom C, Elizabeth City, North Carolina

Wednesday, September 14, 2016, at 7:00 p.m., Commissioner's Meeting Room, Dare County Administration Building, 954 Marshall Collins Drive, Manteo, North Carolina

Wednesday, September 21, 2016, at 7:00 p.m., Martin County Courthouse, 305 E. Main Street, Williamston, North Carolina

Tuesday and Wednesday, October 4 and 5, 2016, at 9:30 a.m., Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman Edward S. Finley, Jr., Presiding; Commissioners Bryan E. Beatty, ToNola D. Brown-Bland, Don M. Bailey, Jerry C. Dockham, James G. Patterson, and Lyons Gray

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BY THE COMMISSION: On March 1, 2016, pursuant to Commission Rule R1-17(a), Virginia Electric and Power Company (VEPCO), d/b/a in North Carolina as Dominion North Carolina Power (DNCP or the Company), filed notice of its intent to file a general rate case application. On the same date, DNCP filed a letter informing the Commission of the Company's intention to propose accounting adjustments to include an appropriate level of amortization of deferred post-in-service costs associated with the Company's Warren County Power Station (Warren County CC) in its rate case revenue requirement.

On March 4, 2016, DNCP filed a Response in Opposition to a motion filed on February 25, 2016, by Nucor in Docket No. E-22, Sub 479, to impose on DNCP additional jurisdictional allocation study filing requirements. On March 7, 2016, CIGFUR I filed a letter stating its position on Nucor's February 25, 2016 motion. On March 17, 2016, the Commission issued an Order denying Nucor's motion and granting alternative relief. In compliance with Paragraph 4 of the Commission's March 17, 2016 Order, DNCP filed a Single CP Cost of Service Study on May 31, 2016.

On March 31, 2016, the Company filed its Application for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina (Application), along with a Rate Case Information Report Commission Form E-1 (Form E-1),[1] and the direct testimony and exhibits of J. Kevin Curtis, Vice President - Technical Solutions; Mark D. Mitchell, Vice President – Generation Construction; James R. Chapman, Senior Vice President - Mergers & Acquisitions and Treasurer; Robert B. Hevert, Managing Partner of Sussex Economic Advisors, LLC; Paul M. McLeod, Regulatory Advisor - Regulatory Accounting Group; Bruce E. Petrie, Manager - Generation System Planning; Michael S. Hupp, Jr., Director - Power Generation Regulated Operations; Glenn A. Pierce,[2] Manager – Regulation; and Paul B. Haynes, Director - Regulation. The Company also filed requests for authority to use certain deferred accounts to implement a levelization methodology for its nuclear unit and refueling

[1] An erratum to DNCP's Form E-1 was filed on July 13, 2016, redacting confidential information from the original.

[2] Witness Pierce's direct testimony was subsequently adopted by witness Haynes.

maintenance outage expenses, as well as relief from the conditions imposed by the Commission in its April 19, 2005 Order approving DNCP's integration into PJM Interconnection, Inc. (PJM), in Docket No. E-22, Sub 418 (PJM Order).

Petitions to intervene were filed by CIGFUR I on March 7, 2016, Nucor on April 4, 2016, NCSEA on April 5, 2016, and CUCA on August 1, 2016. Notice of intervention was filed by the Attorney General on June 13, 2016.

The Commission subsequently entered Orders granting the petitions to intervene of CIGFUR I, NCSEA, Nucor, and CUCA. The Public Staff's intervention is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19. The Attorney General's intervention is recognized pursuant to G.S. 62-20.

On April 20, 2016, Nucor filed a motion requesting *pro hac vice* admission before the Commission for Damon E. Xenopoulos. On June 3, 2016, DNCP filed a motion requesting *pro hac vice* admission before the Commission for Joseph K. Reid, III. Orders allowing these motions for limited practice before the Commission were issued on April 26, 2016, and June 7, 2016, respectively.

On April 26, 2016, the Commission issued an Order Establishing General Rate Case and Suspending Rates. On May 10, 2016, the Commission issued an Order Scheduling Hearings and Requiring Public Notice.

On May 2, 2016, DNCP filed an Application for an Accounting Order to Defer Certain Capital and Operating Costs Associated with Brunswick County Power Station Addition in Docket No. E-22, Sub 533. On May 3, 2016, the Company filed a Motion for Reconsideration of the Commission's March 29, 2016 Order Denying Deferral Accounting for Warren County Combined Cycle Generating Facility in Docket No. E-22, Sub 519.

On May 17, 2016, the Commission issued an Order Consolidating Dockets, which consolidated this general rate case with DNCP's pending petition for deferral accounting authority to defer post-in-service costs associated with commercial operation of the Brunswick County Power Station (Brunswick County CC) in Docket No. E-22, Sub 533, and the Company's motion for reconsideration in Docket No. E-22, Sub 519, of the Commission's Order denying the Company's request to defer post-in-service costs associated with commercial operation of the Warren County CC.

On July 8, 2016, DNCP submitted a supplemental filing pertaining to the Company's request for relief from the conditions imposed by the PJM Order, supported by the supplemental direct testimony of Michael S. Hupp, Jr. and James R. Bailey, Manager – Planning and Strategic Initiatives – Electric Transmission Department.

On August 12, 2016, DNCP filed the supplemental direct testimony and exhibits of James R. Chapman, Deanna R. Kesler, Regulatory Consultant in Demand Side Planning – Integrated Resource Planning, Bruce E. Petrie, Paul M. McLeod, and Paul B. Haynes, as well as applicable updated NCUC Form E-1 information report items.

On September 7, 2016, the Public Staff filed the direct testimony and exhibits of Jack L. Floyd, Engineer, Electric Division; John R. Hinton, Director, Economic Research Division; Michael C. Maness, Assistant Director, Accounting Division; James S. McLawhorn, Director, Electric Division; Jay B. Lucas, Engineer, Electric Division; Dustin R. Metz, Engineer, Electric Division; Katherine A. Fernald, Assistant Director, Accounting Division; and Darlene P. Peedin, Supervisor, Electric Section, Accounting Division. On the same day, Nucor filed the direct testimony of J. Randall Woolridge, Professor of Finance and University Fellow at Pennsylvania State University; Lane Kollen, Vice President and Principal, Kennedy and Associates; Jacob M. Thomas, Senior Project Manager, GDS Associates, Inc.; and witness Dennis W. Goins, Economic Consultant, Potomac Management Group.

On September 7, 2016, CUCA filed a motion requesting a one-day extension of time for it and the other intervenors to file their testimony and exhibits. The Commission issued an Order allowing CUCA's motion on September 8, 2016.

On September 8, 2016, CUCA filed the direct testimony of Kevin O'Donnell, President of Nova Energy Consultants, Inc.; CIGFUR I filed the direct testimony of Nicholas Phillips, Jr., Managing Principal, Brubaker & Associates, Inc.; and Nucor filed the supplemental direct testimony of witness Goins.

On September 26, 2016, DNCP filed the rebuttal testimony and exhibits of J. Kevin Curtis, Mark D. Mitchell, James R. Chapman, Robert B. Hevert, Paul M. McLeod, Mark C. Stevens, Director of Regulatory Accounting, James I. Warren, member of the law firm of Miller & Chevalier Chartered, Michael S. Hupp, Jr., and Paul B. Haynes.

On September 28, 2016, DNCP filed a list of witnesses, the order of witnesses, and estimated time for cross-examination of the witnesses.

On October 3, 2016, the Public Staff filed a notice of settlement in principle. In addition, the Public Staff filed a motion to delay the hearing of expert testimony. The Public Staff requested that the Commission convene the hearing as scheduled on October 4, 2016, at 9:30 a.m., to receive public witness testimony, but delay the start of the testimony by expert witnesses until 1:30 p.m. that afternoon.

Also, on October 3, 2016, DNCP, the Public Staff, and CIGFUR I (Stipulating Parties) entered into and filed an Agreement and Stipulation of Settlement (Stipulation). In addition, DNCP and the Public Staff filed a joint motion to excuse witnesses.

In support of the Stipulation, on October 3, 2016, DNCP filed the testimony and exhibits of J. Kevin Curtis, Robert B. Hevert, and Paul B. Haynes, and the joint testimony of Mark C. Stevens and Paul M. McLeod; and the Public Staff filed the testimony and exhibits of Katherine A. Fernald and John R. Hinton.

On October 4, 2016, Nucor filed a motion to postpone the hearing of expert testimony for 14 calendar days following the filing of the final version of the Stipulation and the additional expert witness testimony, if any. In summary, Nucor asserted that it needed additional time to prepare for the hearing due to the Stipulation recently filed by DNCP, the Public Staff and CIGFUR I.

The public hearings were held as scheduled. The following public witnesses appeared and testified:

Halifax:	Belinda Joyner, Tony Burnette, Larry Abram, Dean Knight, Janice Bellamy, Regina Moffett, and Betty Bennett
Elizabeth City:	Peter Bishop
Manteo:	Robert Woodard, Walter L. Overman, Dwight Wheless, Robert C. Edwards, Manny Medeiros, and Judy Williams
Williamston:	Martha McDonald, John McDonald, Tawilda Bryant, Rhett B. White, Ronnie Smith, John Liddick, Linda Gibson, Samantha Komar, Louise Simmons, Jerry McCrary, Glenda Barnes, and Reginald Williams, Jr.
Raleigh:	No public witnesses appeared.

On October 3, 2016, DNCP filed a Motion for Approval of Undertaking and Notice to Implement Temporary Rates, Subject to Refund, pursuant to G.S. 62-135.

The matter came on for hearing on October 4, 2016, at 9:30 a.m. After determining that there were no public witnesses who desired to testify, the Chairman heard the parties' arguments on the Public Staff's motion to delay the start of the expert witness testimony until 1:30 p.m. that afternoon, and Nucor's motion to postpone the hearing for 14 calendar days. The Chairman ruled that the hearing of expert testimony would commence at 1:30 p.m., on October 4, 2016. Further, the Chairman ruled that the concerns of Nucor and other parties about needing more time to prepare direct testimony and cross-examination regarding the Stipulation would be addressed by rearranging the order of witnesses and other accommodations, if such accommodations became reasonably necessary during the hearing. Thus, the Public Staff's motion was granted, and Nucor's motion was denied, but Nucor's and the other parties' concerns about needing additional time to prepare were resolved.

The expert witness hearing began at 1:30 p.m., on October 4, 2016, and was concluded on October 5, 2016. DNCP presented the testimony of witnesses Curtis, Chapman, Mitchell, Hevert, McLeod, Stevens, Warren, Hupp, and Haynes. The testimony and exhibits of DNCP witnesses Kesler, Bailey, and Petrie were stipulated into the record. Nucor presented the testimony of witness Woolridge. The testimony and exhibits of Nucor witnesses Kollen, Thomas, and Goins were stipulated into the record. CUCA presented the testimony of witness O'Donnell. The testimony of witness Phillips was withdrawn by CIGFUR I.

The Public Staff presented the testimony of witnesses Maness, Fernald, Floyd, and McLawhorn. The testimony and exhibits of Public Staff witnesses Lucas, Peedin, Metz, and Hinton were stipulated into the record.

The pre-filed testimony of those witnesses who testified at the expert witness hearing, as well as all other witnesses filing testimony in this docket, except for CIGFUR I witness Nicholas Phillips, Jr., was copied into the record as if given orally from the stand, and their pre-filed exhibits were admitted into evidence.

On October 11, 2016, the Commission issued a notice of mailing of transcript and ordered that the parties submit briefs and/or proposed orders by November 10, 2016. On November 4, 2016, the Attorney General moved that the date by which briefs and proposed orders must be filed be extended until November 15, 2016. The motion was granted by Order issued November 8, 2016. On November 15, 2016, the Attorney General requested a second extension to November 16, 2016. The motion was granted on November 15, 2016.

On October 12, 2016, the Commission issued an Order Approving Financial Undertaking and an Order Approving Public Notice of Temporary Rates in response to DNCP's Motion for Approval of Undertaking and Notice to Implement Temporary Rates, Subject to Refund.

On October 18, 2016, in response to a request by the Commission during the hearing, DNCP filed additional information regarding its weatherization and other energy assistance programs.

On November 15, 2016, DNCP and the Public Staff filed a late-filed exhibit, as requested by the Commission, comparing the regulatory conditions in the PJM Order with the commitments made by DNCP in the present docket.

Also on November 15, 2016, NCSEA filed a post-hearing Brief.

On November 16, 2016, CUCA filed its Proposed Findings and Brief, and Nucor and the Attorney General's Office filed post-hearing Briefs. In addition, DNCP, the Public Staff and CIGFUR I filed a Joint Proposed Order.

On December 2, 2016, the Public Staff filed a letter on behalf of the Stipulating Parties requesting that the Commission accept revisions to two paragraphs of their Joint Proposed Order regarding Nucor's motion to postpone the expert witness hearing for 14 calendar days.

On December 9, 2016, DNCP filed for informational purposes a letter of December 8, 2016, from DNCP to Nucor regarding the continuation of services to Nucor under the parties’ existing contract and Schedule NS.

On December 13, 2016, DNCP and NCSEA filed a letter informing the Commission of an agreement reached between them regarding DNCP's time-of-use rate offerings.

Based upon consideration of the pleadings, testimony, and exhibits received into evidence at the hearings, the Stipulation, and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

Jurisdiction

1. Virginia Electric and Power Company (VEPCO) is duly organized as a public utility operating under the laws of the State of North Carolina as Dominion North Carolina Power (DNCP or Company) and is subject to the jurisdiction of the North Carolina Utilities Commission. DNCP is engaged in the business of generating, transmitting, distributing, and selling electric power and energy to the public in North Carolina for compensation. DNCP is an unincorporated division of VEPCO and has its office and principal place of business in Richmond, Virginia. VEPCO is a wholly owned subsidiary of Dominion Resources, Inc. (DRI).

2. The Commission has jurisdiction over the rates and charges, rate schedules, classifications, and practices of public utilities operating in North Carolina, including DNCP, under Chapter 62 of the General Statutes of North Carolina.

3. DNCP is lawfully before the Commission based upon its application for a general increase in its retail rates pursuant to G.S. 62-133, 62-133.2, 62-134, and 62-135 and Commission Rule R1-17.

4. The appropriate test period for use in this proceeding is the 12 months ended December 31, 2015, adjusted for certain known changes in revenue, expenses, and rate base through June 30, 2016.

The Application

5. In summary, by its general rate case Application, supporting testimony and exhibits filed on March 31, 2016, in this docket, DNCP sought an increase in its non-fuel base rates and charges to its North Carolina retail customers of $51,073,000, along with other relief, including cost deferrals and changes to its rate design and regulatory conditions. The Application was based upon a requested rate of return on common equity (ROE) of 10.50%, an embedded long-term debt cost of 4.889%, and DNCP’s actual capital structure of 53.36% common equity and 46.64% long-term debt, as of December 31, 2015.

The Stipulation

6. On October 3, 2016, the Public Staff filed a Notice of Settlement in Principle with DNCP and CIGFUR I. On October 3, 2016, the Stipulating Parties entered into and filed the Stipulation resolving all of the issues in this proceeding among the Stipulating Parties.

7. After carefully reviewing the Stipulation, the Commission finds that the Stipulation is the product of give-and-take in settlement negotiations among the Stipulating Parties, and is material evidence entitled to be given appropriate weight by the Commission.

Revenue Requirement and Adjustments to Cost of Service

8. The Stipulation, as reflected on Settlement Exhibits I and II, provides for a stipulated increase in the revenue requirement of $25,790,000, consisting of an increase of $34,732,000 in non-fuel revenues and a decrease of $8,942,000 in base fuel revenues. The Stipulation provides for $375,722,000 of operating revenues, $299,084,000 of operating revenue deductions, and $1,040,035,000 of original cost rate base for use in establishing base rates in this proceeding.

9. The costs of rate base and operating revenue deductions reflected in and underlying the Stipulation, as well as the level of operating revenues under present rates, were prudently and reasonably incurred. These rate base costs and operating expenses are necessary for DNCP to meet its obligation to provide safe, adequate, and reliable electric service.

10. The Stipulation provides for certain accounting adjustments, which are set forth in detail at Settlement Exhibit II. The Stipulating Parties agree that settlement regarding those issues will not be used as a rationale for future arguments on contested issues brought before the Commission. The accounting adjustments outlined in Settlement Exhibit II are just and reasonable to all parties in light of all the evidence presented.

11. For purposes of this proceeding, the Stipulation removes certain site separation costs associated with development of the proposed North Anna Nuclear Station Unit 3 from the stipulated revenue requirement, and additionally provides that consideration of the recovery of such costs is reserved for a future proceeding. The Stipulation's treatment of the North Anna Unit 3 site separation costs is appropriate, just and reasonable to all parties in this case.

EDIT Refund

12. The Stipulation provides that the appropriate level of excess deferred income taxes (EDIT) to be refunded to customers in this case is $15,708,000 (on a pre-income-tax basis), which includes EDIT associated with the January 1, 2017, reduction in the North Carolina corporate state income tax rate from 4% to 3%.

13. DNCP shall implement a decrement rider, Rider EDIT, to refund EDIT to customers over a two-year period on a levelized basis, with a return. As reflected on Settlement Exhibit IV, the appropriate amount to be credited to customers is a total of $16,816,000, which should be credited to customers via a rate that is calculated using the sales shown in Column 1 of Company Rebuttal Exhibit PBH-1, Schedule 11. The ratemaking treatment of the EDIT regulatory liability set forth in the Stipulation is just and reasonable to all parties in light of all the evidence presented.

Implementation of Session Law 2015-6 (House Bill 41)

14. Pursuant to Section 2.4.(a) of House Bill 41 (HB 41), the Commission must adjust the rate for the sale of electricity, piped natural gas, and water and wastewater service to reflect all tax changes enacted in Session Law 2013-316 (HB 998). Under G.S. 105-130.3C, as enacted in HB 998, an automatic reduction in the State corporate income tax rate from 4% to 3% will become effective for the taxable year beginning on or after January 1, 2017, because certain net General Fund tax collection levels were met for the State's fiscal year 2015-2016. The base non-fuel rate revenue requirement in the Stipulation reflects the 3% North Carolina state income tax (SIT) rate effective for the taxable year beginning on or after January 1, 2017.

Nuclear Refueling and Outage Expense Levelization Accounting

15. Section VII of the Stipulation provides that the Company may use levelization accounting for nuclear refueling costs, as described in the testimony of Public Staff witness Fernald and Fernald Exhibit 3. The levelization accounting treatment of the nuclear refueling costs set forth in the Stipulation is just, reasonable and appropriate.

Coal Combustion Residuals (CCR) Costs

16. DNCP's actions through June 30, 2016, in addressing CCR remediation have been prudent, and its CCR costs incurred through June 30, 2016, are reasonable.

17. Section VIII of the Stipulation provides for the Company's deferral and recovery of CCR expenditures incurred through June 30, 2016, and that such costs be amortized over a five-year period. Section VIII of the Stipulation also provides that by virtue of the Commission's approval in this proceeding of a mechanism to provide for recovery of CCR expenditures incurred through June 30, 2016, DNCP has continuing authority pursuant to the Commission's August 6, 2004 Order in Docket No. E-22, Sub 420, to implement asset retirement obligation (ARO) accounting and to defer additional CCR expenditures for consideration for recovery in a future rate case, without prejudice to the right of any party to take issue with the amount or the treatment of any deferral of ARO costs in a future rate case or other appropriate proceeding.

18. The ratemaking treatment of the CCR costs set forth in the Stipulation, as well as the other provisions of the Stipulation regarding CCR costs, are just and reasonable to all parties in light of all the evidence presented.

Regulatory Assets

19. Section XI of the Stipulation provides for deferral accounting treatment and recovery over a three-year period on a levelized basis of deferred post-in-service costs for the Warren County CC and Brunswick County CC.

20. Section XI of the Stipulation also provides for deferral accounting treatment and recovery of the Chesapeake Energy Center (CEC) impairment and closure cost regulatory assets, as proposed by DNCP witness McLeod and further modified by Public Staff witness Fernald.

21. The Stipulation also provides for deferral accounting treatment and recovery of certain regulatory assets and liabilities expiring in 2017 as proposed by Public Staff witness Fernald, which is set forth in Section XI of the Stipulation.

22. The Stipulating Parties agreed to, and by the Stipulation requested Commission approval of, deferral accounting treatment as proposed by Company witness McLeod of costs associated with the beyond design basis studies mandated by the Nuclear Regulatory Commission (NRC) for North Carolina jurisdictional purposes. Through the Stipulation, the Company committed to comply with Commission Rule R8-27(a)(2) prior to establishing any regulatory assets and liabilities for North Carolina jurisdictional purposes in the future.

23. For the present case, the deferral and recovery of the deferred costs presented in the Stipulation is just and reasonable to all parties in light of all the evidence presented.

Accounting for Deferred Costs

24. The Company is authorized to receive a specific amount of revenue for each of the several deferred costs approved by this Order. If the Company receives revenue for any deferred cost for a longer period of time than the amortization period approved by the Commission for that deferred cost, the Company should continue to record all revenue received for that deferred cost in the specific regulatory asset account established for that deferred cost until the Company's next general rate case.

Accounting and Reporting Recommendations

25. Section XIII of the Stipulation provides for certain accounting and reporting commitments by the Company, as recommended by the Public Staff and agreed to by the Company. As a result of the Stipulation, the Company will notify the Commission when the Yorktown Power Station closure occurs and provide estimates of its undepreciated value at the time of closure and the level of costs to be incurred for closure. Additionally, the Public Staff's accounting recommendations concerning the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts (USOA) and the service company charges will be addressed by DNCP and the Public Staff in Docket Nos. E-22,

Subs 476 and 477. Further, the Company agreed in the Stipulation to provide the Public Staff, within 90 days of the date of the Stipulation, with a presentation regarding its accounting practices for non-nuclear asset retirement obligation costs.

Base Fuel Factor

26. The Stipulation provides for a total decrease in DNCP's annual base fuel revenues of $8.942 million from its North Carolina retail electric operations, based on a base fuel factor of 2.073 cents per kilowatt-hour (kWh) (including regulatory fee), which is just and reasonable to all parties in light of all the evidence presented.

27. The base fuel factor should be differentiated between customer classes as provided on Company Rebuttal Exhibit PBH-1, Schedule 9, Page 2.

28. The Stipulation also provides for an adjustment to the Company's base fuel and non-fuel expenses to reflect 78% as a proxy for the fuel cost component of energy purchases for which the actual fuel cost is unknown (Marketer Percentage), with the remaining 22% of the cost of energy purchases being recovered by DNCP in base rates. This represents a reduction from the Company's current Marketer Percentage of 85%. The 78% Marketer Percentage agreed to in the Stipulation is reasonable and appropriate for use in this proceeding. The 78% Marketer Percentage shall remain in effect until the Company's next base rate application or the Company's 2018 application to adjust its annual fuel factor, whichever occurs first.

Capital Structure, Cost of Capital, and Overall Rate of Return

29. Based on the expert witness evidence, the public witness evidence, and the Stipulation, the 51.75% common equity and 48.25% long-term debt, as set forth at Section II.B of the Stipulation, is a just, reasonable, and appropriate capital structure for DNCP in this general rate case.

30. DNCP's June 30, 2016, actual long-term debt cost of 4.650% is appropriate for use in this proceeding.

31. Based on the expert witness evidence, the public witness evidence, and the Stipulation, the rate of return on common equity that the Company should be allowed the opportunity to earn is 9.90% as set forth at Section II.B of the Stipulation. This rate of return on common equity is just, reasonable, and appropriate for DNCP in this general rate case.

32. Based on the expert witness evidence, the public witness evidence and the Stipulation, the overall rate of return that the Company should be allowed the opportunity to earn on the Company's invested capital, including its costs of equity and long-term debt, is 7.367%, as set forth at Section II.B of the Stipulation. This overall rate of return is just, reasonable, and appropriate for use in this general rate case.

33. The authorized levels of overall rate of return and rate of return on common equity set forth above are supported by competent, material, and substantial record evidence, are consistent with the requirements of G.S. 62-133, and are fair to DNCP's customers generally and in light of the impact of changing economic conditions.

34. With respect to the foregoing ultimate findings on the appropriate overall rate of return on rate base and allowed rate of return on common equity for use in this proceeding, the Commission relies on the following more specific findings of fact:

a. DNCP's currently authorized overall rate of return on rate base and allowed rate of return on common equity are 7.80% and 10.20% respectively.[3]

b. DNCP's current base rates became effective on November 1, 2012, and have been in effect since that date.

c. In its Application, DNCP sought approval for rates based on an overall rate of return on rate base of 7.88% and an allowed rate of return on common equity of 10.50%.

d. In the Stipulation, the Stipulating Parties seek approval of an overall rate of return on rate base of 7.367% and an allowed rate of return on common equity of 9.90%.

e. From January 2013 through September 2016, the average authorized ROE for vertically integrated electric utilities was 9.87%. Of the 77 cases decided during that period, 35 included authorized returns of 9.90% or higher. The Commission is not specifically relying on past rate of return on equity determinations authorized for other utilities in determining DNCP's cost of equity and ROE in this case; however, it is appropriate to note such past determinations as a check or as corroboration of the Commission's decision regarding the cost of equity demonstrated by the evidence in the present proceeding.

f. The stipulated overall rate of return on rate base of 7.367% and allowed rate of return on common equity of 9.90% are supported by credible, competent, material, and substantial evidence.

g. The 9.90% rate of return on equity falls between the 10.5% ROE initially requested by the Company and the ROEs recommended by ROE witnesses for Nucor and CUCA (9.0% and 8.6%) and the Public Staff (9.3% before supporting the settlement ROE of 9.90%) in this case.

h. It is appropriate to give substantial weight to the high end of the range of results from Public Staff witness Hinton's updated comparable earnings analysis, where the three highest ROE results - 10.0%, 9.9% and 9.7% - average 9.867%.

[3] Virginia Electric & Power Co., Docket No. E-22, Sub 479, Order Granting General Rate Increase, (Dec. 21, 2012) (2012 Rate Order), Order on Remand (July 23, 2015) (2015 Remand Order).

i. It is also appropriate to give substantial weight to an average of a combination of the updated analytical results of DNCP witness Hevert. The average of his high growth rate multi-stage Discounted Cash Flow (DCF) results, his Capital Asset Pricing Model (CAPM) Value Line market risk premium results, and his bond yield plus risk premium results, is 9.86%.

j. It is not appropriate to approve the single number recommendation of any of the ROE witnesses in this case, nor any one analytical method. Rather, a 9.90% ROE represents a reasonable middle ground, avoiding the extremes reflected in the recommendation of the Company witness on the one end and the recommendations of intervenor witnesses on the other end. A 9.90% ROE is supported by witness Hinton's comparable earnings results. It is also supported by the averaging of witness Hevert's high growth rate multi-stage DCF results, CAPM Value Line market risk premium results, and bond yield plus risk premium results.

k. Substantial expert evidence presented in this matter, uncontroverted by other expert testimony on the subject, indicates that the overall economic climate in North Carolina (as well as nationally) continues to improve. This evidence includes data and projections from reliable sources indicating that in the few months before the hearing in this matter: (1) unemployment rates were declining; (2) real gross domestic product growth was continuing; (3) median household income was growing; and (4) residential electricity costs remain well below the national average. In DNCP's service territory specifically, such data show that: (1) economic conditions remain difficult for many people; (2) but recent changes in economic conditions have been positive, as unemployment has fallen considerably in the last several years and per capita income has been growing.

l. During four public hearings held in Halifax, Manteo, Elizabeth City, and Williamston, the Commission heard testimony regarding economic conditions and the potential impact of DNCP's proposed rate increase on the Company's customers. No public witnesses appeared at the hearing held in Raleigh. Of the 120,000 DNCP retail customers in North Carolina, 26 public witnesses testified at the hearings, many of whom testified that the rate increase was not affordable to many customers, including senior citizens, persons on fixed incomes, persons with disabilities, the unemployed and underemployed, and the poor. The Commission has considered this public witness testimony in its deliberations in setting just and reasonable rates for DNCP, including its determination that a 9.90% ROE and a 51.75% equity component of the stipulated capital structure are reasonable.

m. The rate increase approved in this case, which includes the approved ROE and capital structure, will be difficult for some of DNCP's customers to pay, in particular the Company's low-income customers.

n. The 9.90% rate of return on equity takes into account the impact of changing economic conditions on consumers. The authorized revenue amount available to pay a return on equity is lower for DNCP because the Stipulation reduced downward DNCP's requested revenue requirement, and this reduction is intertwined with the decision on rate of return on equity in that it affects the earnings available to investors and the rates customers will pay.

o. No party submitted evidence showing that any regulatory commission applies increments or decrements to the return on equity to account for economic conditions or customer ability to pay.

p. DNCP has made significant capital investments since its last rate case in 2012, much of which relates to its efforts to add new baseload combined cycle generating capacity to its fleet and to expand and strengthen its transmission and distribution infrastructure in northeastern North Carolina and throughout its system. All of these investments further the mission of ensuring reliability, operational excellence, and efficient electric service for DNCP's customers. The Company plans to make additional significant capital investments in the future.

q. Continuous safe, adequate, and reliable electric service by DNCP is essential to the well-being of the people, businesses, institutions, and economy of North Carolina, and access to capital at reasonable rates is critical to DNCP's ability to fund its ongoing capital investment requirements and DNCP's provision of safe, reliable, and cost effective electric service.

r. The 9.90% ROE and the ratemaking capital structure consisting of 51.75% common equity approved by the Commission in this case result in a cost of capital that will enable DNCP by sound management to produce a fair return for its shareholders, and is just, reasonable, and fair to DNCP's customers considering the impact of changing economic conditions on those customers. The resulting cost of capital is as low as reasonably possible and appropriately balances DNCP's need to obtain financing and maintain a strong credit rating with its customers' need to pay the lowest possible rates.

s. The potential difficulties that DNCP's low-income customers will experience in paying DNCP's increased rates will be somewhat mitigated by the $400,000 of shareholder funds that the Company will contribute to assist low-income customers.

Revenue Increase

35. The Stipulation provides for an increase in DNCP's annual electric sales revenues from its North Carolina retail electric operations of $34.732 million. With the stipulated decrease in annual base fuel revenues of $8.942 million, there is a net overall revenue increase of $25.790 million from its North Carolina retail electric operations. The increase in annual non-fuel base rates to be paid by DNCP's North Carolina retail customers is just and reasonable to all parties in light of all the evidence presented.

EnergyShare Contribution

36. Section XV of the Stipulation provides that the Company will make a one-time $400,000 shareholder contribution to the North Carolina EnergyShare program that provides energy assistance to customers in need in the Company's North Carolina

service territory. This $400,000 will be an additional contribution in 2017 on top of the Company's usual annual contribution of about $360,000. This shareholder contribution represents an additional rate mitigation measure that could not have been ordered by the Commission without agreement by the Company. This provision of the Stipulation is just and reasonable to all parties in light of all the evidence presented.

Cost of Service Allocation Methodology

37. The Stipulation provides for the use of the Summer-Winter Peak and Average (SWPA) methodology to allocate the Company's cost of service to the North Carolina jurisdiction and among the customer classes in this case. The Stipulating Parties agreed that use of the SWPA methodology for allocation between jurisdictions and among customer classes shall not be a precedent for, and may be contested in, future general rate case proceedings. The Stipulating Parties further agree that the Company's proposed adjustment to DNCP's recorded summer and winter peaks to recognize the peak demand contributions of non-utility generators (NUGs) interconnected to the Company's distribution system is appropriate and reasonable. The SWPA cost of service methodology, as adjusted by DNCP to account for the peak demand contribution of distribution-connected NUGs, is appropriate for determining the Company's North Carolina jurisdictional and retail customer class cost allocation and responsibility for purposes of this case.

38. DNCP's adjustment to the peak component of SWPA appropriately recognizes the impact non-utility generators have on DNCP's utility system and is appropriate for use in this proceeding.

39. The SWPA cost of service methodology, as adjusted by DNCP, has been used in this Order to determine the appropriate levels of rate base, revenues, and expenses for North Carolina retail service.

40. DNCP's continued use of the SWPA methodology in this proceeding properly assigns production plant costs to all customer classes, including the Schedule NS Class in recognition of its significant use of the Company's generation throughout the year.

41. It is not reasonable nor necessary at this time to require the Company to re-evaluate the issues addressed in the 1994 fuel study filed in Docket No. E-22, Sub 333, as raised by Nucor.

Rate Design

42. For purposes of apportioning and assigning the approved increase in base non-fuel and base fuel revenues between the North Carolina customer classes in this proceeding, the apportionment and rate design principles presented by Company witness Haynes in his direct and rebuttal testimony, as modified in Section V of the Stipulation, are reasonable, appropriate, and nondiscriminatory. The Stipulation further provides that in developing rates based upon the foregoing class apportionment, the Company agrees

to recover 100% of the stipulated revenue increase through the energy and demand components of rates and not to increase the basic customer charge component of rates.

Schedule 6L

43. The new Rate Schedule 6L, as amended in Company Rebuttal Exhibit PBH-1, Schedule 12 to eliminate the NAICS "Manufacturing" classification as part of the qualification for this rate schedule, is reasonable, nondiscriminatory, and should be approved.

Utilities International Model (UI Model)

44. The Stipulation provides that DNCP will work with its cost of service model vendor to determine whether an application can be produced that would enable an intervenor or the Public Staff to perform certain cost of service model functionalities in Excel, generally including manipulating allocation factors to prepare their own cost of service studies in future rate case proceedings. DNCP should work with its vendor, Utilities International, to assess reasonable additional cost of service model functionalities that can be produced in an Excel spreadsheet-based format. DNCP should be prepared prior to filing its next general rate case to release the Excel product to intervenors as requested.

LED Schedule

45. The Stipulation provides that the Company shall develop and file for Commission approval a new LED schedule for North Carolina jurisdictional customers within one year of the Commission's final order in this proceeding. This provision of the Stipulation is reasonable and appropriate.

Time-Differentiated Rates

46. DNCP currently does not offer a Real Time Pricing (RTP) rate for its service territory in North Carolina. It is reasonable to expect the Company to propose a pilot or experimental RTP rate offering no later than July 1, 2017.

47. The number of DNCP residential customers receiving service on either of the time-of-use rates offered by DNCP in North Carolina is approximately 0.3%. In 2008, the Commission encouraged utilities to increase the utilization of time-differentiated rates. However, the percentage of DNCP's residential customers participating is smaller now than it was in 2007. Therefore, DNCP should be required to provide a written summary of its time-of-use rates, and its RTP rates, when developed, to each residential customer presently being served and to be served in the future by a smart meter. Further, the Commission approves the terms of the agreement filed herein by DNCP and NCSEA on December 13, 2016.

Terms and Conditions

48. The Stipulation provides that DNCP's Terms and Conditions should be revised as set forth in Item 39 of the Company's Form E-1 filed with its supplemental direct testimony on August 12, 2016. The rate designs, rate schedules, and service regulations proposed by the Company are reasonable, as filed, except as specifically addressed in the Stipulation and this Order.

Quality of Service

49. The overall quality of electric service provided by DNCP is good.

PJM Conditions

50. It is appropriate to relieve the Company from compliance with most, but not all, of the conditions that were imposed by the Commission's April 19, 2005 Order Approving Transfer Subject to Conditions issued in Docket No. E-22, Sub 418. The Company shall continue to file with its annual fuel clause adjustment filing the information required by Paragraph 5 of the November 10, 2004 Joint Offer of Settlement between DNCP and PJM. The Independent Market Monitor (IMM) for PJM shall continue to annually file the information required by Paragraph 6 of that same Joint Offer of Settlement. DNCP committed in the Stipulation to comply with the representations and commitments made in its July 8, 2016 Supplemental Filing with respect to certain obligations, and that provision of the Stipulation is just and reasonable. Further, it is appropriate to require the Company to file as a compliance filing in this case a comprehensive document entitled "Code of Conduct" that shall include all representations and commitments to which the Company will be bound, consistent with this Order.

Acceptance of the Stipulation

51. Based upon all of the evidence in the record, including consideration of the public witness testimony and the record evidence from parties who have not agreed with the Stipulation, the provisions of the Stipulation are just and reasonable to the customers of DNCP and to all parties to this proceeding, and serve the public interest. Therefore, the Stipulation should be approved in its entirety. In addition, the Stipulation is entitled to substantial weight and consideration in the Commission's decision in this docket.

Just and Reasonable Rates

52. The base non-fuel and base fuel revenues approved herein are just and reasonable to the customers of DNCP, to DNCP, and to all parties to this proceeding, and serve the public interest.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-4

The evidence supporting these findings of fact and conclusions is contained in the verified Application and Form E-1 of DNCP, the testimony and exhibits of the witnesses, and the entire record in this proceeding. These findings and conclusions are informational, procedural, and jurisdictional in nature, and are not contested by any party. In addition, the Commission finds and concludes that the Company's use of a test period of the 12 months ended December 31, 2015, with appropriate adjustments through June 30, 2016, comports with the requirements of G.S. 62-133 and Commission Rule R1-17, and is appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

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

On March 1, 2016, pursuant to Commission Rule R1-17(a), DNCP filed notice of its intent to file a general rate case application. On the same date, DNCP filed a letter informing the Commission of the Company's intention to propose accounting adjustments to include an appropriate level of amortization of deferred post-in-service costs associated with the Company's Warren County Power Station (Warren County CC) in its rate case revenue requirement.

On March 31, 2016, DNCP filed its Application and initial direct testimony and exhibits, seeking a net increase of approximately $ 51,073,000 in its annual electric sales revenues from its North Carolina retail electric operations. The Application is based on a requested rate of return on common equity (ROE) of 10.50%, an overall rate of return of 7.88%, an embedded long-term debt cost of 4.889%, and DNCP's actual capital structure of 53.36% common equity and 46.64% long-term debt, as of December 31, 2015. Further, the Application states that DNCP's 2015 ROE was 5.06%, and its overall rate of return was 4.98%.

The Company's last general rate case was in 2012 in Docket No. E-22, Sub 479. By Order issued on December 21, 2012, the Commission approved an increase in DNCP's base non-fuel revenues of $36,438,000, and a decrease of $14,484,000 in its base fuel revenues. DNCP's current authorized ROE is 10.2%, its authorized overall rate of return is 7.8%, and its authorized capital structure for ratemaking purposes is 51% common equity, 1.5% preferred stock and 47.5% long-term debt.

In its present Application, the Company proposed to implement the non-fuel base rate increase on a temporary basis subject to refund effective on November 1, 2016, along with an accelerated implementation of its new lower base fuel rate – to be filed in August 2016 – as part of any temporary rates (subject to refund) proposed to become effective November 1, 2016. The Company also proposed a methodology for returning certain excess accumulated deferred income taxes (EDIT) to customers through a decrement rider, Rider EDIT, over a two–year period; sought authority to use certain deferred accounts to implement a levelization methodology on its books for its nuclear unit refueling and maintenance outage expenses; and requested an adjustment of the Marketer Percentage to 100%. Further, DNCP requested the deferral of several costs that it had incurred. Finally, DNCP requested relief from the regulatory conditions imposed in the PJM Order.

In its supplemental testimony filed on August 12, 2016, DNCP updated the increase sought in its non-fuel base rates and charges to its North Carolina retail customers to $47.8 million. Upon making certain adjustments, DNCP updated the increase sought to $46.8 million in rebuttal testimony filed on September 26, 2016.

The Commission finds and concludes that DNCP's Application satisfies the requirements of G.S. 62-133, et seq., and Commission Rule R1-17. Further, DNCP is a public utility within the meaning of G.S. 62-3(23). Therefore, pursuant to G.S. 62-30, et seq., the Commission has jurisdiction to consider and decide DNCP's Application for a rate increase and other relief.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 6-7

The evidence supporting these findings of fact and conclusions is contained in the testimony of DNCP's witnesses Curtis, Haynes, Hevert, McLeod and Stevens, Public Staff witness Hinton, the provisions of the Stipulation, and the entire record in this proceeding.

On October 3, 2016, DNCP, the Public Staff and CIGFUR I (Stipulating Parties) filed a Stipulation resolving all of the issues among the Stipulating Parties. The Stipulation is based on the same test period as the Company's Application. In summary, the Stipulation provides:

- A $34.7 million increase in DNCP's annual non-fuel base revenues;

- A $8.9 million decrease in DNCP's annual fuel base revenues;

- A 2-year Excess Deferred Income Taxes decrement rider (Rider EDIT) returning to ratepayers excess deferred income taxes in the amount of approximately $15.7 million beginning November 1, 2016;

- An overall base rate increase for all customer classes of approximately 7.47%, excluding the effect of any 2017 Fuel Factor Riders and the Rider EDIT decrement;

- An increase to residential customers' bills for 2017 limited to 0.08%, taking into account the effect of the base rate increase, overall fuel decrease, the Company's proposed 2017 Fuel Factor Riders, and the Rider EDIT decrement;

- A rate of return on equity of 9.90% and an overall rate of return on rate base of 7.367%;

- A capital structure for ratemaking purposes consisting of 51.75% equity and 48.25% long-term debt;

- An embedded cost of debt of 4.650%;

- A 5-year amortization of costs associated with coal combustion residual expenditures incurred through June 30, 2016;

- Withdrawal from this case of DNCP's request to recover site separation costs associated with the proposed North Anna 3 nuclear plant. Consideration of the recovery of any such costs would be reserved for a future proceeding;

- Allocation of the Company's cost of service based on the Summer/Winter Peak and Average (SWPA) method;

- A one-time $400,000 shareholder contribution by DNCP to the EnergyShare program that provides energy assistance to customers in need in the Company's North Carolina service territory;

- Deferral of the post-in-service costs of the Warren County CC and Brunswick County CC generating facilities;

- Deferral of the Chesapeake Energy Center (CEC) impairment and closure costs; and

- Subject to certain clarifications and conditions, release of DNCP from further compliance with the regulatory conditions imposed by the Commission in its Order Approving Transfer Subject to Conditions, Docket No. E-22, Sub 418 (April 19, 2005), approving DNCP's participation in PJM.

In his testimony in support of the Stipulation, filed on October 3, 2016, DNCP witness Curtis stated that the Company was able to reach a settlement with the Public Staff after extensive discovery conducted by the Public Staff and other intervenors. Witness Curtis further testified that the Stipulation is the product of give-and-take negotiations between the Company and the Public Staff. He testified that through extensive discussions and negotiations with the Public Staff, the Company and Public Staff were able to strike the balance between reasonable rates for customers and the Company's need to attract capital in order to continue providing safe and reliable service. In addition, witness Curtis testified that the Company understands that the Commission must set just and reasonable rates, including the authorized ROE, in a way that balances the economic conditions facing DNCP's customers with the Company's need to attract capital in order to continue providing safe and reliable service. He testified that the Stipulation mitigates the impact on DNCP's customers of the rate relief provided to the Company through, for example, the agreed-upon cost of service adjustments, the reduced overall revenue requirement, the decreased base fuel factor, and the refund of excess deferred income taxes through decrement Rider EDIT. Witness Curtis also noted that the Stipulation provides significant benefits that could not otherwise be ordered by the Commission, including the accelerated refund of the current fuel over-recovery through decrement Rider A1, and the Company's agreement to make a $400,000 contribution of shareholder funds to the North Carolina EnergyShare program, to provide energy assistance to customers in need in DNCP's North Carolina service area.

Company witness Hevert filed testimony on October 3, 2016, in support of the Stipulation. He testified that although the ROE agreed upon in the Stipulation is below the lower end of his recommended range (i.e. 10.25%), he recognizes that the Stipulation represents the give-and-take regarding multiple issues that would otherwise be contested.

Company witnesses Stevens and McLeod filed joint testimony on October 3, 2016, in support of the Stipulation. They testified that subsequent to the filing of the Company's Application, DNCP, the Public Staff and other intervenors engaged in substantial discovery, and that the parties filed testimony asserting their positions, with DNCP also filing rebuttal testimony responding to the other parties' positions. Witnesses Stevens and McLeod further testified that after lengthy negotiations the Company and Public Staff arrived at a settlement of all of the issues between them. Witnesses Stevens and McLeod also noted that DNCP negotiated in good faith with other parties, and was able to reach a settlement with CIGFUR I. In addition, witnesses Stevens and McLeod stated that the Stipulation is the result of give-and-take negotiations in which each party made substantial compromises on certain issues in order to gain compromises from the other party on other issues, and that the Stipulating Parties believe the results reached are fair to the Company and its customers. Finally, they noted that the Stipulation resolves all issues among the Stipulating Parties without the necessity of contentious litigation.

DNCP witness Haynes also filed testimony on October 3, 2016, in support of the Stipulation. Witness Haynes testified that he believes the Stipulation constitutes a just and reasonable approach to establishing DNCP's cost of service, apportioning the costs among the customer classes, and designing the Company's rates and charges. Moreover, he testified that the Stipulation represents a compromise between differing interests in a number of respects, including CIGFUR I's support of the Company's proposed SWPA cost allocation methodology, and CIGFUR I's withdrawal of its request that an additional portion of the rate increase be allocated to the NS Class.

Public Staff witness Hinton also filed testimony in support of the Stipulation on October 3, 2016. Witness Hinton testified that the Public Staff and DNCP have fundamentally different views of the current market conditions and cost of capital, and that neither party persuaded the other to change its views. He testified that the Public Staff and DNCP nonetheless found a way to bridge their differences and to reach agreement on a proposed ROE and capital structure. Witness Hinton further stated that the stipulated ROE of 9.90% and equity ratio of 51.75% came about as a result of various compromises on other issues by both DNCP and the Public Staff. In addition, Public Staff witness Fernald testified to her belief that the Stipulation is in the public interest.

The Stipulation has not been adopted by all of the parties to this docket. Therefore, the Commission's determination of whether to accept or reject the Stipulation is governed by the standards set out by the North Carolina Supreme Court in State ex rel. Utilities Commission v. Carolina Utility Customers Association, Inc., 348 N.C. 452, 500 S.E.2d 693 (1998) (CUCA I), and State ex rel. Utilities Commission v. Carolina Utility Customers Association, Inc., 351 N.C. 223, 524 S.E.2d 10 (2000) (CUCA II). In CUCA I, the Supreme Court held that

> [A] stipulation entered into by less than all of the parties as to any facts or issues in a contested case proceeding under Chapter 62 should be accorded full consideration and weighed by the Commission with all other evidence presented by any of the parties in the proceeding. The Commission must consider the nonunanimous stipulation along with all the evidence presented and any other facts the Commission finds relevant to the fair and just determination of the proceeding.
>
> The Commission may even adopt the recommendations or provisions of the nonunanimous stipulation as long as the Commission sets forth its reasoning and makes "its own independent conclusion" supported by substantial evidence on the record that the proposal is just and reasonable to all parties in light of all the evidence presented.

348 N.C. at 466, 500 S.E.2d at 703.

However, as the Court made clear in CUCA II, the fact that fewer than all of the parties have adopted a settlement does not permit the Court to subject the Commission's Order adopting the provisions of a nonunanimous stipulation to a "heightened standard" of review. 351 N.C. at 231, 524 S.E.2d at 16. Rather, the Court said that Commission approval of the provisions of a nonunanimous stipulation "requires only that the Commission ma[k]e an independent determination supported by substantial evidence on the record [and] ... satisf[y] the requirements of chapter 62 by independently considering and analyzing all the evidence and any other facts relevant to a determination that the proposal is just and reasonable to all parties." Id., at 231-32, 524 S.E.2d at 16 (emphasis added).

The Commission gives substantial weight to the testimony of DNCP witnesses Curtis, Haynes, McLeod and Stevens describing the Stipulating Parties' efforts in negotiating the Stipulation. Further, the Commission gives significant weight to the settlement testimony of Public Staff witnesses Fernald and Hinton, which in their discussion of the benefits that the Stipulation will provide to customers and their testimony describing the compromise reflected in the Stipulation's terms indicate the Public Staff's commitment to fully represent the using and consuming public. In addition, the Commission gives some weight to the fact that the settlement was not reached until October 3, 2016, the day before the expert witness hearing began. Prior to that date, DNCP, the Public Staff and CIGFUR I pre-filed the testimony of their experts setting forth their litigation positions on the issues. That indicates to the Commission that the Stipulating Parties were fully prepared to litigate the contested issues in the event that a settlement was not reached.

As a result, the Commission finds and concludes that the Stipulation is the product of the give-and-take among the Stipulating Parties during their settlement negotiations in an effort to appropriately balance DNCP's need for increased revenues and its customers' needs to receive safe, adequate, and reliable electric service at the lowest possible rates. In addition, the Commission finds and concludes that the Stipulation was entered into by the Stipulating Parties after substantial discovery and negotiations, and that it represents a proposed negotiated resolution of the matters in dispute in this docket among the Stipulating Parties. As a result, the Stipulation is material evidence to be given appropriate weight in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 8-11

The evidence supporting these findings of fact and conclusions is contained in DNCP's verified Application, the direct, supplemental and rebuttal testimony and exhibits of the witnesses, the Stipulation, and the entire record in this proceeding.

Rate Base

Per Settlement Exhibit I of the Stipulation, the amount of original cost rate base is $1,040,035,000. A breakdown of the components of the original cost rate base is as follows (000's omitted):

Line No.	Item	After Rate Increase
1	Electric plant in service	$1,947,252
2	Accumulated depreciation and amortization	(716,858)
3	Net electric plant in service (L1 + L2)	1,230,394
4	Materials and supplies	44,916
5	Cash working capital	18,476
6	Other additions	19,607
7	Other deductions	(17,434)
8	Customer deposits	(5,126)
9	Accumulated deferred income taxes	(250,799)
10	Rounding	1
11	Total original cost rate base (Sum of L3 thru L10)	$1,040,035

Discussion of Certain items included in Rate Base

North Anna 3 Site Separation Costs

The Company's Application included certain North Anna Power Station "site separation" plant investments in DNCP's rate base for ratemaking purposes.

Public Staff witness Metz testified that the North Anna Power Station consists of two nuclear reactors, North Anna Units 1 and 2, that are in-service, as well as a potential site for a third nuclear reactor, known as North Anna 3, for which DNCP has not sought a certificate of public convenience and necessity from the Virginia State Corporation Commission (SCC), a determination of need from this Commission pursuant to G.S. 62-110.6, or approval from this Commission of its decision to incur project development costs pursuant to G.S. 62-110.7. In the Company's most recent integrated resource plan (IRP) in Docket No. E-100, Sub 147, DNCP indicates that it is engaged in development efforts in regard to North Anna 3 and is currently pursuing a Combined Operating License from the NRC, which is expected next year.

Witness Metz testified that the Company has included in its cost of service certain capital investment and related expenses associated with site preparation activities for North Anna 3. Site activities for North Anna 3 have involved removing existing structures/buildings that support North Anna Units 1 and 2, and then relocating them outside of the proposed construction zone of North Anna 3.

Witness Metz cited Company witness Mitchell's testimony in SCC Case No. PUE-2015-00027 that stated, "[t]he services supported by each of these assets will be used by the operating Units 1 and 2 as well as Unit 3 if the Company proceeds with construction. However, but for the development of North Anna 3, the development of these assets would not have been needed." Further, in rebuttal in that same case, witness Mitchell stated: "I highlight that but for the development of North Anna 3, these preconstruction site separation activities would not have been needed." Public Staff witness Metz asserted that these costs should be assigned to North Anna 3 and thus removed from DNCP's cost of service in this proceeding.

Similarly, Nucor witness Kollen testified that the site separation costs are solely related to North Anna 3, and not North Anna 1 and 2; therefore, these costs should be removed from rate base and depreciation expense in this proceeding. Witness Kollen additionally testified that in the Company's most recent biennial review, the Virginia SCC removed the North Anna 3 costs from rate base and operating expense that it was not required to include pursuant to Virginia state law (70% of new nuclear construction costs incurred between July 1, 2007, and December 31, 2013).

In rebuttal, Company witness Mitchell provided a brief history of North Anna Units 1 and 2 and explained the decision making process to move forward with North Anna 3 development as part of the Company's resource planning strategy. Witness Mitchell explained that North Anna Units 1 and 2 are benefiting from the new buildings and how these common facilities would eventually support a third nuclear unit at the site. The new facilities, including warehouses, paint shops, welding areas, and vehicle repair shops, are now in service supporting the operating North Anna station, including Units 1 and 2. Witness Mitchell disputed Public Staff witness Metz's characterization of the activities in question as "site preparation activities for North Anna 3" rather than "site separation activities" needed for North Anna, testifying that the new support buildings and infrastructure are needed today in order to continue the safe and reliable operations of North Anna Units 1 and 2. Witness Mitchell testified that this limited universe of costs are site "separation" investments that are now in service and being used to support operations at North Anna Units 1 and 2.

Company witness Stevens disagreed with Public Staff witness Metz's and Nucor witness Kollen's claim that the North Anna site separation costs are solely related to North Anna 3, not to North Anna Units 1 and 2. While the future development of an additional nuclear unit was the driver of the overall project, witness Stevens explained that the site separation assets are common assets that are used and useful assets today at North Anna. Witness Stevens asserted that the Company's accounting for the site separation assets is also consistent with the FERC USOA. As such, he insisted that the site separation assets – which are now in-service and are used and useful today – should not be recorded in construction work in progress (CWIP), but appropriately recorded in plant-in-service.

In his rebuttal testimony, witness Stevens testified that the Virginia SCC did not remove North Anna 3 rate base and operating expenses in the Company's most recent biennial review in Virginia – it included the recovery of 70% of "all costs" related to North Anna 3 as a period expense in the Company's earnings test results for fiscal year 2014. Specifically, he testified that the Virginia legislature has provided explicit direction to the Virginia SCC through Va. Code § 56-585.1 regarding the manner in which VEPCO, operating in Virginia as Dominion Virginia Power, shall be authorized to recover the costs of new generating facilities (including recovery of CWIP) and other utility plant. DNCP witness Stevens asserted that the Virginia cost recovery statute should have no bearing on DNCP's recovery of the North Carolina portion of site separation costs under the North Carolina Public Utilities Act. According to witness Stevens, prudently incurred investments in plant-in-service that are used and useful today to serve the Company's North Carolina customers are recoverable under the North Carolina Public Utilities Act.

Witness Stevens asserted in his rebuttal testimony that Nucor witness Kollen's calculation of its adjustment to remove the site separation costs was overstated. According to DNCP witness Stevens, witness Kollen imputed depreciation expense for the assets rather than evaluating the actual depreciation expense reflected in the cost of service. Witness Stevens further testified that Nucor witness Kollen also failed to adjust for accumulated deferred income taxes associated with the site separation assets, thereby incorrectly reducing rate base.

For purposes of this proceeding, the Stipulation provides that certain site separation costs associated with development of the proposed North Anna Nuclear

Station Unit 3 be removed from the stipulated revenue requirement, and that consideration of the recovery of such costs shall be reserved for a future proceeding. Based on this proceeding and the entire record as a whole, the Commission finds and concludes that the Stipulation's treatment of the North Anna Unit 3 site separation costs is appropriate, just and reasonable in this case.

Cash Working Capital (CWC)

In his direct testimony, Company witness McLeod testified that the CWC requirement is based on a lead/lag study prepared based on calendar year 2013 data. According to witness McLeod, the CWC calculation for regulatory purposes is consistent with DNCP's lead/lag study methodology described in the Company's Reply Comments filed in Docket No. M-100, Sub 137, and meets the requirements identified in the Commission's March 21, 2016 Order Clarifying Order on Lead-Lag Study Procedure.

Public Staff witness Fernald identified and proposed a number of adjustments and corrections to the Company's calculation of CWC in her testimony. Additionally, the Public Staff adjusted CWC under present rates to reflect all of the Public Staff's adjustments, in accordance with the Commission's Order in Docket No. M-100, Sub 137.

Nucor witness Kollen testified that the Company's CWC calculation includes the following non-cash expenses: depreciation and amortization expense; deferred federal and state income tax expense, and income available for common. Witness Kollen argued that these non-cash expenses are typically excluded in the lead-lag calculation for that reason, and recommended that the Commission exclude these non-cash expenses from the lead/lag calculation.

As reflected in the rebuttal testimony of Company witness McLeod, DNCP reviewed Public Staff witness Fernald's testimony and exhibits and accepted each of the revisions to the Company's lead-lag study and allowance for CWC, as adjusted by witness Fernald, with the exception of the current state income tax expense lead days. Company witness McLeod testified that the Company disagreed with the Public Staff's correction to the current income tax expense lead days because the Company's expense lead days are based on all current tax payments during the year. Witness McLeod explained that the Company does not necessarily agree with the Public Staff's other revisions to the expense lead and revenue lag days, but has accepted the changes for purposes of this proceeding due to their minor impact on the overall base non-fuel rate revenue requirement.

In his rebuttal testimony, Company witness Stevens disputed Nucor witness Kollen's recommendation to exclude certain non-cash items from the determination of CWC. Witness Stevens explained that the Company's treatment of these items is consistent with the Company's prior practices and this Commission's prior treatment of lead-lag studies and CWC. According to witness Stevens, the Commission had previously addressed the same issue also raised by Nucor in Docket No. M-100, Sub 137, and the Commission overruled Nucor's position. Witness Stevens recommended that the

Commission reject Nucor's adjustment to exclude these expenses from the lead-lag calculation.

The Commission notes that the allowance for CWC in the Stipulation includes an expense lead for current income taxes based on the statutory filing deadlines as proposed by Public Staff witness Fernald. The Commission finds and concludes that for the present case the CWC allowance presented in the Stipulation and agreed to by DNCP and the Public Staff is just and reasonable to all parties in light of all the evidence presented. With respect to Nucor witness Kollen's recommendation regarding certain non-cash items, Nucor has not presented any new evidence to dissuade the Commission from its findings and conclusions addressing inclusion of non-cash items in CWC, as set forth in its May 15, 2015, Order Ruling on Lead-Lag Study Procedure*,* in Docket M-100, Sub 137. Therefore, the Commission rejects Nucor's position regarding the exclusion of certain non-cash items in the calculation of CWC.

Accumulated Deferred Income Taxes Due to Bonus Depreciation on Brunswick County CC

In its supplemental filing, DNCP updated its rate base as of June 30, 2016. DNCP witnesses testified that this calculation also incorporated both the investment and the accumulated deferred income taxes (ADIT) associated with the recently completed Brunswick County CC. Embedded in the ADIT calculation is the impact of bonus depreciation as recorded on the Company's books and records as of June 30, 2016.

Nucor witness Kollen testified that the Company calculated ADIT due to first year bonus depreciation for the Brunswick County CC and included only six months as a subtraction from rate base. According to witness Kollen, bonus depreciation is taken when the asset is placed in service for tax purposes and the entirety of the ADIT is available at June 30, 2016, not just half (or six months) as reflected in the Company's filing. Witness Kollen contended that the Company chose to allocate the bonus depreciation equally over the months in calendar year 2016 in the filing; however, this understates the ADIT available from bonus depreciation at June 30, 2016. Witness Kollen recommended that the Commission reflect the full federal ADIT from bonus depreciation at June 30, 2016.

In response to Nucor witness Kollen, in his rebuttal testimony Company witness Warren discussed the history of bonus depreciation, and explained that bonus depreciation is conceptually no different from other forms of accelerated depreciation; it represents an incentive provided by the government for stimulating capital investment. Witness Warren testified that by allowing businesses to claim accelerated depreciation, Congress essentially causes the government to extend interest-free loans to those enterprises. These loans, according to witness Warren, produce incremental cash (*i.e.,* a reduction in the amount of tax otherwise payable), which are presently available to the utility, but will have to be paid back to the government over time. He further testified that the repayment of such loans is effected by filing future tax returns. Witness Warren explained that the outstanding loan balance is reflected as an ADIT credit, which is properly reflected as a reduction to rate base. In this way, ratepayers receive the entire benefit of the interest-free feature of the loan.

DNCP witness Warren testified that the nature of the disagreement between the Company and witness Kollen is over how much of the ADIT benefit of the Company's 2016 bonus depreciation should be recognized when computing its rate base as of June 30, 2016. The Company contends that it should recognize a half year's worth of the benefit. Witness Kollen contends that it should recognize 100% of the benefit. Witness Warren explained that on DNCP's accounting records, it spreads the benefits of accelerated tax depreciation ratably over the entire year in which the accelerated depreciation is claimed. He stated that this methodology is not one that it applied only to the Brunswick County CC facility or used only for purposes of calculating ADIT in this proceeding. In fact, as of June 30, 2016, the Company's accounting records reflect 50% of the benefit of the bonus depreciation (as well as of the "regular" accelerated tax depreciation on the non-deducted cost) it will claim on its 2016 tax return relating to Brunswick County CC facility. Thus, the ADIT the Company has recognized for purposes of this proceeding conforms to the ADIT it has recognized for all other purposes. Witness Warren further testified that witness Kollen's proposal recognizes an ADIT amount for purposes of the Company's rate base calculation that does not appear on its books and records.

Witness Warren testified that witness Kollen's assertion that the bonus depreciation deduction is taken when the asset is placed in service is both inaccurate and irrelevant. The Brunswick County CC bonus depreciation deduction will not be taken until DNCP files its 2016 federal income tax return in the second half of 2017. According to witness Warren, the critical issue is when the cost-free capital produced by the Company's ability to claim bonus depreciation with respect to the Brunswick County CC facility becomes available to the Company. According to witness Warren, witness Kollen incorrectly presumes that this occurs when the facility is placed in service.

Witness Warren explained that the Company acquires the cost-free capital produced by accelerated depreciation on the facility by reducing its estimated tax payments. As a tax year progresses, corporations are required to make four estimated tax payments so that they pay their tax liability during the year – not when they file their tax return. The amount of the quarterly estimated tax payments, according to Witness Warren, is equal to the lesser of: (1) one-fourth of the tax liability for the year; or (2) an amount calculated by annualizing the taxable income generated during the period. In terms of alternative (1) above, one-fourth of the impact of any bonus depreciation claimed during the year will reduce each of the four estimated tax payments. Thus, the effect of bonus depreciation is spread ratably throughout the year. Therefore, under alternative (1), the ADIT recorded on the Company's books and records as of June 30, 2016, accurately reflects the cost-free capital in its possession. Witness Warren contended that witness Kollen's proposed adjustment imputes a quantity of cost-free capital that, in fact, did not exist as of June 30, 2016.

Witness Warren explained that under alternative (2) above, the applicable tax regulation, Treasury Regulation §1.6655-2(f)(3)(iv), dictates how depreciation must be handled when a taxpayer annualizes its taxable income. It provides that, in determining taxable income for any annualization period, a proportionate amount of the taxpayer's estimated annual depreciation is taken into account. Thus, the benefit of the bonus depreciation actually claimed during the first period is spread over all four periods. Therefore, under alternative (2), the ADIT recorded on the Company's books and records as of June 30, 2016, accurately reflects the cost-free capital in its possession. Witness Warren contended that witness Kollen's proposed adjustment would again impute a quantity of cost-free capital that did not exist as of June 30, 2016.

Further, witness Warren testified that witness Kollen's proposal also creates a conflict with the tax depreciation normalization rules (Normalization Rules). The Normalization Rules are established by §168(i)(9) of the Internal Revenue Code of 1986, as amended, and Treas. Reg. §1.167(l)-1. They are quite complex, but prescribe: (1) how to implement the required tax benefit deferral (*i.e.*, normalization); (2) what can be done with the deferred tax benefit once it is deferred; and (3) under what circumstances the deferred tax benefit can be reversed. Witness Warren explained that accelerated depreciation was enacted by Congress to promote investment by businesses (including utilities) in plant and equipment. However, Congress was concerned that, in the case of a regulated utility whose rates are set by reference to its costs (one of which is tax expense), these incentives could be extracted from the utility and flowed directly to its customers through the rate-setting process, and the benefits would be stripped from the utilities and converted into consumption subsidies for utility customers who did not necessarily use the money to make plant investments. According to witness Warren, this was not Congress' intent, and it included in the tax law a set of rules to prevent this from happening – the Normalization Rules.

Witness Warren further explained that because the Normalization Rules permit rate base to be reduced by the cost-free capital produced by claiming accelerated depreciation, the benefits of accelerated depreciation that those rules intend to preserve can be passed through to ratepayers by ratemaking that presumes the existence of an excessive quantity of cost-free capital. DNCP witness Warren testified that the Normalization Rules therefore impose a limit on the amount of depreciation-related ADIT by which rate base can be reduced. Witness Warren contended that the limitation that is relevant to witness Kollen's proposed adjustment is the one contained in Treasury Regulations §1.167(l)-1(h)(6) entitled "Exclusion of normalization reserve from rate base." Treasury Regulations Section §1.167(l)-1(h)(6)(i) states, in pertinent part:

> [A] taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes under section 167(l) which is excluded from the base to which the taxpayer's rate of return is applied…exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's tax expense in computing cost of service in such ratemaking.

This regulation requires that rate base not be reduced by an ADIT balance unless that balance has been included in the utility's cost of service. Witness Warren testified that the additional six months of ADIT that witness Kollen proposes to factor into the Company's rate base computation has not been included in the Company's cost of service. Witness Warren asserted that only the amount that has been reflected on the Company's accounting records – the amount that it has used in its rate base computation – has been included in cost of service.

Witness Warren testified that as a condition for claiming accelerated tax depreciation (including bonus depreciation) on any of its depreciable assets, a utility must use a normalization method of accounting. Thus, the penalty for a violation in this proceeding would not be confined to the Brunswick County CC facility, but would extend to all of the Company's North Carolina depreciable assets. Witness Warren explained that the penalty for violating the Normalization Rules is draconian. By no longer being able to claim accelerated depreciation, a non-compliant utility would not generate any additional interest-free, governmental loans. Moreover, witness Warren stated that all governmental loans outstanding as of the date of the violation would have to be paid back a good deal more rapidly than would otherwise have been the case. The inability to claim accelerated tax depreciation would result in a significant reduction in the quantity of cost-free loans such depreciation deductions produce. Company witness Warren attested that this would manifest itself in the form of a dramatically reduced ADIT balance. Since the Company's ADIT balance offsets the rate base upon which a return must be allowed, diminished ADIT balances will produce a higher rate base and, consequently, higher rates than had the normalization violation not occurred.

The Stipulation reflects ADIT from bonus depreciation for the Brunswick County CC as of June 30, 2016, as a reduction to rate base as proposed by the Company.

Based upon the evidence presented by Company witness Warren, the Commission concludes that witness Kollen's proposal to reflect the full federal ADIT from bonus depreciation for the Brunswick County CC as a reduction to rate base as of June 30, 2016, is unreasonable and inappropriate. The Commission agrees with Company witness Warren that DNCP acquires the cost-free capital produced by accelerated depreciation on the facility by reducing its estimated tax payments made over the course of the tax year. As of June 30, 2016, the Company had only acquired half of this benefit, which DNCP has appropriately reflected as a reduction to rate base. The Commission, therefore, finds and concludes that the ADIT reflected in the Stipulation associated with the Brunswick County CC bonus depreciation is just and reasonable to all parties in light of all the evidence presented.

Operating Expenses

Operating Expenses per the Stipulation are $299,084,000. A breakdown of the operating expenses allowed in this proceeding is as follows:[4]

Line No.	Item	Amount (000's omitted)
1	Electric operating expenses:	
2	Operations and maintenance:	
3	Fuel clause expenses	$90,686
4	Other operations and maintenance expenses	98,989
5	Depreciation and amortization	60,047
6	Gain / loss on disposition of property	309
7	Taxes other than income taxes	15,233
8	Income taxes	33,820
9	Total electric operating expenses (Sum of L3 thru L8)	$299,084

Discussion of Certain items included in Operating Expenses

Uncollectible Expense

In its Application, DNCP proposed a normalization adjustment to uncollectible expense based on an historical average uncollectible expense rate for the five-year period of 2011-2015. Public Staff witness Fernald presented testimony stating that in 2014, the Company changed its write-off and collection policies for customers with medical certifications. According to witness Fernald, prior to that time, although these customers existed, the Company did not include them in its determination of the reserve for uncollectibles. She further testified that in 2014, DNCP began including customers with medical certifications in its calculation of the reserve, and to implement this policy change the Company recorded a $12.1 million credit accounting adjustment, on a total system level, to its reserve for uncollectibles account, with a charge to uncollectible expense, in order to establish an initial reserve for these customers. Witness Fernald testified that data from 2014 and prior years should not be used to determine an ongoing level of uncollectibles, since data from those years cannot validly be compared with 2015 data. Accordingly, witness Fernald stated that she calculated uncollectibles based on 2015 data, reflecting the Company's current policy of establishing a reserve for customers with

[4] Chart omits 000's.

medical certificates. Witness Fernald noted that the uncollectibles rate utilized by the Public Staff was 0.4814% as compared to the Company's 0.5549% rate.

Company witness McLeod testified that the Company's adjustment based on a five-year historical average expense rate methodology was consistent with the methodology approved by the Commission in the 2012 rate case, Docket No. E-22, Sub 479 (2012 Rate Case), as well as the Company's prior 2010 rate case, Docket No. E-22, Sub 459 (2010 Rate Case). Witness McLeod noted that the methodology approved in the 2012 Rate Case, which the Company followed in its Application, was first proposed by Public Staff witness Fernald in that proceeding. Witness McLeod argued that a change in accounting policy should not negate the use of an historical average since the purpose of using a historic average is to recognize the volatile nature of the expense - capturing both the highs and lows – and include a "normal" level that the Company will incur over a reasonable period of time. He asserted that normalization adjustments are designed to smooth out volatility in interim years including changes in accounting policy.

The Stipulation provides for an adjustment to uncollectible expenses based on 2015 data as proposed by witness Fernald. The Commission finds and concludes that for the present case the accounting adjustment is just and reasonable to all parties in light of the agreement between the Company and the Public Staff in the Stipulation and all the evidence presented.

<u>Major Storm Restoration Expense</u>

The Company proposed a normalization adjustment to non-labor and overtime major storm restoration expenses based on an historical average of costs during the five-year period of 2011-2015. Company witness McLeod testified that this adjustment is appropriate for ratemaking purposes given the unpredictable nature of storm activity, which can cause a material level of expense in a short period of time.

Public Staff witness Fernald proposed to normalize major storm expense based on the average storm costs for the last 10 years, instead of the last five years as proposed by the Company. Witness Fernald testified that the use of a 10-year average is consistent with the normalization of storm costs in the recent rate cases for Duke Energy Carolinas in Docket No. E-7, Subs 909, 989, and 1026, and for Duke Energy Progress in Docket No. E-2, Sub 1023. In addition, due to the unpredictability of both the frequency and cost of major storms, she contended that a 10-year average is more appropriate for use in determining a normalized level. Witness Fernald further recommended that since the Company has a normalized level of storm costs included in rates in this case, costs for future storms should not be deferred nor amortized.

Nucor witness Kollen testified that the data indicates that there is no "normal" storm damage expense and that a "normalized" expense is highly dependent on the number of years used for that purpose, as there are significant differences from year to year. Witness Kollen recommended that the Commission implement storm damage reserve accounting for ratemaking purposes and calculate the storm damage expense using the three most recent years of expense. According to Witness Kollen, this proposal would allow for the tracking of storm damage costs and the recovery of storm damage expenses on a dollar-for-dollar basis with the net over/under recovery position as a component of rate base. Witness Kollen further testified that any storm costs more or less than the expense accrual, under this scenario, would be tracked in the reserve and he suggested that the Commission could periodically adjust the storm damage expense to target a zero reserve balance over time.

In rebuttal testimony, witness McLeod testified that the Public Staff's reliance on a 10-year average understates the normal level of storm expenses that can be expected to occur going-forward. Witness McLeod asserted that the Public Staff's reliance on 10 years of data also fails to take into account operational changes that have occurred over that period of time.

In rebuttal testimony, Company witness Stevens recommended that the Commission reject Nucor witness Kollen's proposal to establish a ratemaking mechanism for tracking DNCP's storm costs. Witness Stevens contended that the methodology presented by Company witness McLeod is reasonable, and that witness Kollen's storm damage tracker goes beyond any known Commission precedent.

The Stipulation provides for an adjustment to major storm restoration expenses based on data during the period January 1, 2010 to June 30, 2016, in effect, including a levelized storm restoration expense level less than the five-year average recommended by the Company and greater than the level proposed by Public Staff. The Commission finds and concludes that for the present case this stipulated level of storm expense is reasonable and appropriate and is just and reasonable to all parties in light of all the evidence presented. The Commission also finds that Nucor witness Kollen's recommendation for the Commission to order a storm cost tracker should not be implemented in light of the Commission's preceding determination to include storm restoration expense in the cost of service.

Annual Incentive Plan Expense

In the Company's Application, Company witness McLeod explained that the annual incentive plan (AIP) represents at-risk compensation paid out to Company employees only upon meeting certain operational and financial goals during the plan year. During 2015, not all of the operational and financial goals of the Company were achieved, and, as a result, less than 100% of at-risk compensation was paid to employees. Witness McLeod proposed in his direct testimony an accounting adjustment that provides for 100% of the plan target based on employees meeting all operational and financial goals during the year.

Public Staff witness Fernald testified that she agreed that incentive pay, such as DNCP's AIP, represents a part of employees' overall compensation. However, witness Fernald explained that the actual amounts paid to employees under the AIP could vary widely. AIP payout percentages in the last five years have ranged from a 20% payout during the test year to 100% payouts in 2013 and 2014. Witness Fernald recommended that the three-year average of the payout percentage, amounting to 73.33%, be used to determine the amount of AIP expense for this proceeding.

Nucor witness Kollen recommended that the ratemaking level of AIP expense should be limited to the lesser of: (a) the expense incurred in the test year, if the Company's actual payout was less than 100% of target; or (b) 100% of target, if its payout exceeded 100% of target. Witness Kollen contended that the concept underlying the AIP is that employees are paid for performance and that a portion of their payroll is at risk and the Commission should not require customers to pay for performance that the Company did not achieve. Witness Kollen proposed to reduce the Company's adjustment from 100%, as proposed, down to 20% to reflect the actual test year payout.

Company witness McLeod testified in rebuttal that the methodology used by the Company in this case is consistent with the methodology approved by the Commission in 2012 Rate Case. Witness McLeod requested that the Commission again allow the Company to incorporate AIP expense at the 100% target payout percentage and to continue to incentivize high employee performance for the benefit of DNCP's customers. Witness McLeod asserted that Nucor witness Kollen's ratemaking adjustment for AIP expense was asymmetric. Witness McLeod testified that the AIP payout percentage during the test year was the single lowest payout in at least the past eight years.

The Stipulation provides for a normalized level of AIP expense based on the three-year average of the payout percentage of 73.33% as proposed by witness Fernald. The record shows that the Company's AIP payout percentage is, on average, well above the 20% payout percentage recommended by witness Kollen. Therefore, the Commission finds and concludes that for the present case the level of AIP expense presented in the Stipulation is just and reasonable to all parties in light of all the evidence presented.

<u>Employee Severance Program Costs</u>

In the Company's supplemental filing, witness McLeod proposed to include a normalized level of employee severance program costs for ratemaking purposes based on the average severance program costs during the years 1994 through 2016. The normalized annual level of severance costs was determined by dividing the average severance program costs by 4.4 years, the average frequency of severance programs as determined by the Company.

Public Staff witness Fernald explained that in the 2012 Rate Case, an ongoing level of severance program costs was included in rates based on the actual costs of the Company's 2010 employee severance program, which at that time was its latest corporate-wide severance program. Witness Fernald discussed DNCP's most recent employee severance program, the Organizational Design Initiative (ODI), which was announced during the first quarter of 2016. Witness Fernald recommended that the level of employee severance program costs for ratemaking purposes in this proceeding be based upon the actual cost of the most recent corporate-wide severance program, amortized over five years. These costs are lower than the employee severance costs allowed in the 2012 rate case, according to witness Fernald, but this reflects the fact that the costs of ODI, and the savings it generated for ratepayers, were lower than those of the Company's previous programs.

Nucor witness Kollen testified that the scope and frequency of prior employee severance has varied considerably, and thus there is no "normal" employee severance program cost. According to witness Kollen, the Company's change in methodology from its initial filing to its update filing demonstrates how the "normalized" expense can be affected by the selection of the programs to be included, the scope and cost of the programs, and the frequency of the programs. It also demonstrates, according to witness Kollen, that one event can significantly affect the average cost, amortization period, and amortization expense.

Witness Kollen recommended that the Commission reject the approach proposed by the Company. Instead, he recommended that the Commission establish a policy that allows the Company to defer the costs of major severance programs, subject to a reasonableness test showing savings in excess of costs, and then amortize and recover those costs over a reasonable period coincident with reflecting the savings in rates, including a return on the unamortized costs. In this case, witness Kollen proposed that the Commission authorize the Company to defer the costs of the ODI, include the costs in rate base, and amortize the costs over a 10-year period, which is equivalent to the longest interval without a severance program in the last 27 years.

In rebuttal testimony, Company witness McLeod explained that in the 2012 Rate Case, the Commission concluded the normalized level of employee severance program costs should reflect "actual historical operating experience" and "should be recovered at a level consistent with DNCP's historical practice…." According to witness McLeod, the Public Staff and Nucor are calculating the going level of severance program costs based solely on ODI, which is by far the least cost program in the past 22 years.

DNCP witness Stevens, in his rebuttal testimony, disputed Nucor witness Kollen's recommendation for the Commission to establish a deferral accounting approach to employee severance program costs. Stevens contended that the deferral mechanism approach suggested by Nucor does not meet the standard or threshold the Commission sets for establishing regulatory assets. According to witness Stevens, the matter is really a debate about the appropriate level of expense to reflect in the cost of service for ratemaking purposes.

The Stipulation provides for a normalized level of employee severance program costs based on the cost of ODI over a five-year period, as recommended by the Public Staff. The Commission finds and concludes that for the present case the accounting adjustment presented in the Stipulation is just and reasonable to all parties in light of all the evidence presented. This approach is consistent with the methodology approved by the Commission in the Company's most recent rate case, which provided for an ongoing level of employee severance program costs and is consistent with DNCP's historical practice of instituting such programs. The Commission in not persuaded by witness Kollen's recommendation to establish a deferral accounting practice for severance costs to be amortized over a protracted period of time. Therefore, the Commission concludes that Nucor witness Kollen's recommendation should be rejected.

Section 199 – Domestic Production Activities Deduction

In supplemental testimony, Company witness McLeod defined the Section 199 – Domestic Production Activities Deduction (Section 199 Deduction or DPAD) as a federal incentive pursuant to Internal Revenue Code §199, which is a permanent benefit available for the generation of electricity – *i.e.,* a federal incentive to manufacture certain goods in the United States. The deduction is equal to 9% of the Company's taxable income attributable to the generation of electricity. Witness McLeod proposed a ratemaking Section 199 Deduction based on a five-year average for the years 2011-2015, on a stand-alone basis for DNCP.

Public Staff witness Fernald explained that the Section 199 Deduction is a tax credit that can be taken by DNCP on the taxable income associated with generation of electricity. A major factor in the computation of taxable income, according to witness Fernald, is the amount of tax depreciation, including bonus depreciation, taken by the Company. Witness Fernald stated that the more bonus depreciation taken, the greater the tax deduction for depreciation expense, and the lower the taxable income. Witness Fernald further explained that the amount of bonus depreciation that could be taken was different in 2011 than what could be taken in 2012 through 2015. In 2011, under the then-current tax laws 100% of the cost of newly acquired property could be deducted as bonus depreciation; however, beginning January 1, 2012, the bonus depreciation deduction decreased to 50% of the cost of the property, where it is set to remain until December 31, 2017. After that it is set to decrease to 40% for 2018, and then to 30% for 2019. Public Staff witness Fernald additionally testified that due to the 100% bonus depreciation deduction in 2011, the Company experienced a net operating loss for that year and was thus unable to utilize the Section 199 Deduction for that tax year. Based on all the above information, witness Fernald concluded that 2011 should not be included in calculating the average Section 199 Deduction, and instead recommended that the Section 199 Deduction be calculated based on the average of the four years from 2012 through 2015, the years for which bonus depreciation was at the current rate of 50%.

Nucor witness Kollen discussed the calculation of the retention factor and claimed the Company failed to include the DPAD in the retention factor (applicable to the increase in taxable income resulting from the rate increase). Witness Kollen testified that the Section 199 Deduction was calculated as 9% of the utility's production taxable income subject to various potential limitations. In the ratemaking process, according to witness Kollen, the test year income tax expense included in the revenue requirement was calculated in two steps. The first step calculates the income tax expense included in operating income and in the operating income deficiency before the rate increase. This calculation includes the Section 199 Deduction on production taxable income, including the effects of any limitations. The second step calculates the income tax expense on the rate increase resulting from the claimed operating income deficiency. The operating income deficiency was grossed up for income taxes and other revenue related expenses through the retention factor to calculate the revenue deficiency or rate increase. Witness Kollen testified that in this second step, the income tax expense on the rate increase was included in the rate increase itself. According to witness Kollen, the calculation assumes that the entirety of the rate increase is subject to income taxes and should reflect all related deductions, including the Section 199 Deduction, and the Section 199 Deduction is fully available without any limitation because the limitations are already embedded into the calculation of the operating income deficiency. Witness Kollen proposed to revise the Section 199 Deduction stating that the federal income tax rate should be reduced by the 9% Section 199 Deduction times the ratio of the production rate base to the sum of the production, transmission, and distribution rate base before it is reflected in the calculation of the retention factor.

In rebuttal testimony, Company witness McLeod explained that Public Staff witness Fernald changed the allocation factor used by the Company for the SIT expense Section 199 Deduction from the Net Book Income factor to the production allocation factor (Factor 1). According to witness McLeod, this is inconsistent with witness Fernald's recommendation to allocate all income tax expense based on the Net Book Income factor.

Witness McLeod concluded that the five-year average Section 199 Deduction produces a reasonable result that should be utilized for ratemaking purposes.

Company witness Warren testified in rebuttal that tax law permits a business to claim a Section 199 Deduction equal to 9% of the lesser of: (1) certain qualified net income (referred to as QPAI); (2) the taxpayer's taxable income; or (3) 50% of the W-2 wages associated with the production of the QPAI. To qualify as QPAI, according to witness Warren, the net income has to be derived from specified activities associated with manufacturing, and the generation of electricity is an eligible activity. Witness Warren asserted that Nucor witness Kollen's proposal was inappropriate because it assumes the DPAD is fully available without any limitation. Witness Warren explained that the DPAD is limited; it is only available for QPAI. Moreover, witness Warren testified that it is limited by taxable income and by 50% of W-2 wages and, therefore, cannot be presumed to be "fully available." Witness Warren contended that witness Kollen's approach implicitly presumes that additional revenue will produce additional QPAI in the same amount and that there will be no taxable income or W-2 wage limitation on the DPAD computation. Unlike other tax deductions, witness Warren explained that the amount of the DPAD is a function of the interaction of a number of variables, and presuming that additional revenues will necessarily produce additional DPAD is overly simplistic.

Witness Warren explained that the Financial Accounting Standards Board (FASB) analyzed and characterized the DPAD in 2004, soon after the enactment of the tax law provision that established the DPAD, and considered how to properly reflect the DPAD for financial reporting purposes. Witness Warren testified that the FASB made a determination that the Section 199 Deduction should not be treated as an adjustment to the income tax rate, but instead, it should be treated as a "special deduction," which is recognized only in the year in which it is deductible on the tax return. The reason for this conclusion was that the DPAD is contingent upon the future performance of specific activities, including the level of wages. Witness Warren contended that the FASB's conclusion is consistent with his recommendation to exclude the DPAD from the retention factor.

Company witness Stevens contended that Nucor witness Kollen double counted the Section 199 Deduction by incorporating his own adjustment, while also leaving in the Company's standalone regulatory accounting adjustment for the Section 199 Deduction in the revenue requirement. According to witness Stevens, witness Kollen also misapplied his own methodology by applying the change in the retention factor to the Company's entire North Carolina jurisdictional rate base. The proper ratemaking exercise, according to witness Stevens, is to derive a Section 199 Deduction effect only for the additional revenue required to produce the targeted return on equity. Stevens testified that Nucor witness Kollen overstated the impact of the proposed retention factor by $1.5 million. Witness Stevens also testified that other electric utilities under the jurisdiction of the Commission do not utilize a retention factor that is comprised of a Section 199 Deduction, and witness Kollen's proposal represents a significant deviation from past regulatory practice for electric utilities in North Carolina and would lead to inaccurate results. Witness Stevens recommended that the Commission reject witness Kollen's proposal.

The Stipulation provides for a normalized level Section 199 Deduction based on an historical average for the four years 2012-2015 as recommended by Public Staff witness Fernald.

Based on the foregoing, the Commission finds and concludes that Nucor witness Kollen's proposal to include the Section 199 Deduction as a component of the retention factor is inappropriate. The Commission does not find the evidence presented by Nucor witness Kollen convincing, nor does it agree that the incremental revenue increase approved in this case would produce an additional Section 199 Deduction tax benefit. The Commission agrees with the testimony of Company witness Warren that the Section 199 Deduction is more appropriately characterized in the current proceeding as a special deduction, subject to taxable income and wage limitations. Thus, the Commission finds and concludes that it is inappropriate to include the Section 199 Deduction as a component of the retention factor for purposes of determining revenue requirement. Further, the Commission finds and concludes that for the present case the accounting adjustment presented in the Stipulation is just and reasonable to all parties in light of all the evidence presented.

Income Tax Expense Allocation

Public Staff witness Fernald testified that the Company allocated income tax expense as follows:

(1) The Company allocated current and deferred SIT expense to North Carolina retail based on the net book income.

(2) The Company allocated the deferred federal income tax (FIT) expense (i.e., the federal income tax expense associated with revenues and expense items that are recognized in different periods for tax purposes due to timing differences) based on the nature of the timing differences.

(3) The Company allocated the current federal income tax expense based on federal taxable income.

Witness Fernald contended that the income tax expense included in the cost of service for ratemaking should be the amount of income tax expense based on book taxable income, regardless of whether for tax purposes the Company will pay that tax now or later due to timing differences. Therefore, witness Fernald stated, the more appropriate allocation factor for income tax expense is the net book income factor. As such, Public Staff witness Fernald proposed an adjustment to allocate all income tax expense based on net book income.

In rebuttal testimony, Company witness McLeod testified that Schedule 6 (Current Income Tax) and Schedule 7 (Deferred Income Tax) of the Company's cost of service study (COSS) in NCUC Form E-1, Item 45a include detailed calculations of current and deferred FIT expense on both a system level and North Carolina jurisdictional basis. Witness McLeod explained that Schedule 6 contains computations of taxable income for the test period based on the level of operating revenue and expense as determined in the Company's other COSS schedules and an allocation of the various book/tax timing differences, and deferred taxes are allocated among the Company's four jurisdictions in COSS Schedule 7 based on the underlying book/tax timing difference, which corresponds with Schedule 6. Witness McLeod noted that this methodology is consistent with the methodology approved in both of DNCP's most recent rate cases - the 2010 Rate Case and the 2012 Rate Case. Witness McLeod noted that although the Public Staff's audit did not reveal any inherent flaws in the Company's methodology, the Public Staff recommended a complete departure from the methodology proposed by the Company.

Witness McLeod explained that the Company allocates SIT expense to the North Carolina jurisdiction based on the Net Book Income factor because the Company does not have the same level of detail for SIT expense during the test year as it did for FIT expense. Witness McLeod asserted that under these circumstances, it is appropriate to make simplifying assumptions in order to produce a reasonable result for ratemaking purposes. Witness McLeod explained that the Company does, however, have detailed information regarding the book/tax timing differences for FIT expense, and as a result, the methodology in the COSS produces a more accurate and precise allocation of FIT expense than the Public Staff's approach.

According to Company witness McLeod, there are two primary reasons why the methodology in COSS produces a more precise allocation of FIT expense than the Net Book Income factor. First, witness McLeod testified that the Net Book Income factor does not account for all of the permanent differences between book income and taxable income, which causes the Company's effective tax rate to deviate from the statutory rate and will cause the effective tax rate to be different between the Company's jurisdictions. The second item that will cause the Net Book Income factor to not properly reflect North Carolina's appropriate allocable portion of FIT expense, according to witness McLeod, is income tax credits. Witness McLeod argued that since income tax credits are not included in the calculation of the Net Book Income factor, the Public Staff's proposed methodology overrides the allocator designated in the COSS and replaces it with the Net Book Income factor resulting in an inappropriate shift of tax benefits between the jurisdictions. In concluding his testimony, witness McLeod recommended that the Commission allocate FIT expense based on the methodology in the Company's cost of service study since this provides a more precise determination of North Carolina jurisdictional FIT expense.

The Stipulation allocates FIT expense based on the methodology in the Company's cost of service study, as recommended by Company witness McLeod. The Commission finds and concludes that for the present case, the accounting adjustment is just and reasonable to all parties in light of all the evidence presented.

Non-Fuel Variable O&M Expense Displacement

Public Staff witness Maness testified that DNCP made pro forma adjustments to include in the cost of service the full costs of the Brunswick County CC, which began commercial operation on April 25, 2016, including adding incremental non-fuel variable operating and maintenance (O&M) expenses to reflect a full year of operation. With the addition of the Brunswick County CC, witness Maness testified that other plants in DNCP's fleet will operate less frequently, and thus incur fewer non-fuel variable O&M expenses. Therefore, witness Maness asserted, the Public Staff proposed to adjust non-fuel variable O&M expenses to prevent the inclusion in cost of service of more than an annual level of these types of expenses. Otherwise, operating revenue deductions would include both (1) a general annualized and normalized level of variable expenses and (2) the incremental variable expenses related to specific new generation facilities.

In his rebuttal testimony, Company witness McLeod testified that the Company agrees with certain aspects of witness Maness' adjustment for purposes of this case. Specifically, the Company agrees that the addition of the Brunswick County CC will result in some level of purchased power energy savings recovered through base non-fuel rates, and thus proposed in its rebuttal testimony a purchased energy savings adjustment to reduce purchased energy costs proportionate to a pro forma level of the Brunswick County CC generation. However, witness McLeod testified that the Company disagrees with the portion of the adjustment pertaining to energy-related expenses not adjusted elsewhere for growth. Witness McLeod explained that the adjustment is premised on the fact that the Company has included a fully annualized level of Brunswick County CC operating expenses, which was the Company's intent. However, upon further evaluation, the Company determined that its initial adjustment to annualize the Brunswick County CC O&M expense did not include a provision for maintenance outage expenses, which will result in a significant level of cost when incurred. Furthermore, witness McLeod testified that witness Maness' displacement adjustment also does not account for these maintenance outages as the adjustment assumes that the Brunswick County CC will operate for 12 full months. According to witness McLeod, the Public Staff's displacement adjustment, if accepted in full, would understate the level of energy-related expenses necessary to serve the end-of-period customers at the normalized level of generation.

In rebuttal testimony, witness McLeod proposed a new accounting adjustment that reflects an annualized level of purchased energy savings in base non-fuel rates as a result of the Brunswick County CC commencing commercial operation. Witness McLeod recommended that the Commission reject Public Staff witness Maness' displacement adjustment, and incorporate witness McLeod's adjustment that reflects an annualized level of purchased power energy savings for the Brunswick County CC.

The Stipulation reflects an annualized level of purchased power energy savings for the Brunswick County CC as proposed by Company witness McLeod. At the hearing, Public Staff witness Maness testified that while not necessarily agreeing with all aspects of the calculation of this adjustment, the Public Staff accepted it in the Stipulation for purposes of this proceeding only.

Based on the testimony of Public Staff witness Maness and DNCP witness McLeod, and the Stipulation, the Commission finds and concludes that the O&M displacement adjustment, as agreed to in the Stipulation, is just and reasonable to all parties in light of all the evidence presented and should be accepted for purposes of this proceeding.

Depreciation Rates for Warren County CC and Brunswick County CC

Nucor witness Kollen testified that for depreciation expense and rates reflected in the revenue requirement for Warren County CC and Brunswick County CC, the Company used the per books depreciation expense for June 2016, after several adjustments detailed in its workpapers, and annualized the adjusted depreciation expense. According to witness Kollen, the depreciation rates for the per books depreciation expense were provided to the Company by witness John Spanos, a consultant with Gannett Fleming, in a single page letter. The letter included no additional support, analyses, or workpapers, all of which typically are provided in conjunction with an actual depreciation study performed by an expert. The letter states that the depreciation rates "are based on a 36-year life span, interim survivor curves and future interim net salvage percents where applicable. Each of these parameters is established with the general understanding of the new facility and the estimates of comparable Dominion facilities." Witness Kollen stated that the letter provides the proposed interim survivor curve, net salvage rates, and annual depreciation accrual rates for each plant account.

Witness Kollen testified that the Commission should not simply accept the Company's proposed depreciation expense and rates for these units. Witness Kollen contended that there is no support for the parameters used by witness Spanos other than general references to other units owned and operated by the Company. Witness Kollen asserted that he had reviewed the relevant pages from the Company's most recent depreciation studies, and found that the survivor curves and net salvage parameters proposed by witness Spanos did not match any of the Company's other units. He also found that there was a range of life spans for the Company's other CC units from 34 years to 45 years.

In support of his position, witness Kollen testified that one of witness Spanos' colleagues, Ned W. Allis, recommended a 40-year life span for new combined cycle units in a pending Florida Power & Light Company (FPL) proceeding, a change from the 35-year life span that witness Allis recommended in the prior FPL proceeding for new combined cycle units. With that evidence, witness Kollen recommended a 40-year life span for the Warren County CC and Brunswick County CC. Nucor witness Kollen testified that this is the midpoint of the range for the Company's other combined cycle units and is the same life span recommended by witness Allis. Witness Kollen further recommended that the Commission ignore projected interim retirements and net salvage in this proceeding since these units are new and have almost no history of interim retirements or net salvage. Witness Kollen argued that these parameters should be introduced and supported by competent evidence in the Company's next depreciation study.

In response to Nucor witness Kollen's proposal, Company witness Stevens explained in rebuttal that the Company's depreciation consultant provided specific guidance on appropriate depreciation accruals based on informed judgment for Warren County CC and Brunswick County CC. Witness Stevens stated that expert opinion directs that a 36-year useful life for Warren County CC and Brunswick County CC is appropriate given the operating characteristics of these combined cycle units, reviews of Company practice and outlook as they relate to Company operation and retirement, experience of similar existing units within DNCP's generation fleet, and current practice in the electric industry.

DNCP witness Stevens further testified that electric utilities do not experience the exact same performance of a generation facility across the U.S. The expected useful life of a given unit is specific to each utility based on the operating performance of similar units within its owned fleet, the maintenance performance of those units, as well as the expected dispatch characteristics of those units. Witness Stevens contended that a Florida utility's natural gas combined-cycle facility would likely have a different set of operating parameters and conditions and impact on equipment than a natural gas combined-cycle facility constructed by the Company in Virginia.

Witness Stevens also explained that DNCP owns no other combined cycle units with a useful life greater than 36 years. The natural gas combined cycle facilities at Bellemeade, Rosemary, Gordonsville, Chesterfield Unit 7, Chesterfield Unit 8, Possum Point Unit 6, and Bear Garden all have a useful life of 36 years as determined by the Company's depreciation consultant. Witness Stevens noted that this depreciation study was filed with the Commission on April 1, 2013, in Docket No. E-22, Sub 493. Therefore, based on the facts presented, he rejected witness Kollen's testimony that a 40-year life span is the midpoint of the range for the Company's other combined cycle units as inaccurate.

With respect to Nucor witness Kollen's recommendation that the Commission ignore interim cost of removal and net salvage into its depreciation accrual rates for Warren County CC and Brunswick County CC in this proceeding, witness Stevens testified that this practice would be contrary to Generally Accepted Accounting Principles and the FERC USOA.

Witness Stevens further recommended that the Commission reject Nucor's proposed adjustment to the depreciation accruals for Warren County CC and Brunswick County CC.

The Stipulation reflects depreciation expense for the Warren County CC and Brunswick County CC based on the depreciation accrual rates proposed by DNCP.

Based upon the evidence presented in this proceeding, the Commission finds and concludes that the depreciation accrual rates proposed by DNCP for the Warren County CC and Brunswick County CC are appropriate and should be utilized for ratemaking purposes in this case. The Commission concludes that the evidence presented by DNCP supports a useful life of 36 years for these facilities as reasonable for ratemaking purposes until the Company performs another depreciation study. The Commission concludes that Nucor witness Kollen's recommendation to ignore interim cost of removal and net salvage is unsubstantiated and witness Stevens' testimony that witness Kollen's proposal would be contrary to Generally Accepted Accounting Principles and the FERC USOA has not been challenged. Accordingly, the Commission finds and concludes that this recommendation should not be adopted.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12-14

The evidence supporting these findings of fact and conclusions is contained in the verified Application, the testimony and exhibits of Company witnesses McLeod, Haynes, and Stevens and Public Staff witnesses Fernald and Floyd, and the Stipulation.

In the Company's Application, Company witness McLeod testified that HB 998 was signed into law on July 23, 2013. According to witness McLeod, prior to the passage of HB 998, the North Carolina SIT rate was 6.9%, and HB 998 made the following changes to the NC SIT Rate:

- Reduced to 6% effective January 1, 2014;
- Reduced to 5% effective January 1, 2015; and
- Reduced to 4% effective January 1, 2016, assuming certain triggering events occurred, as set forth in the legislation.

Witness McLeod explained that after the passage of HB 998, the accumulated deferred North Carolina SIT balance was overstated based on the legislative changes to the statutory corporate tax rate, or in other words, contained "excess" deferred income taxes (EDIT). In its Order Establishing Procedure for Implementation of Session Law 2015-6 in Docket No. M-100, Sub 138 issued on September 11, 2015, the Commission ordered DNCP to hold the EDIT in a regulatory liability account to be refunded to ratepayers in the context of DNCP's next general rate case proceeding. Witness McLeod testified that the Company is proposing a methodology in this case for crediting the North Carolina jurisdictional portion of the EDIT to customers as this is the first general rate case since the Company established the EDIT regulatory liability.

Company witness McLeod proposed to refund the EDIT to customers through a decrement rider over a two-year period (Rider EDIT). This mechanism, according to witness McLeod, provides transparency as the credit is differentiated from the base rate cost of service. Additionally, excluding the credit from the base rate cost of service will defer the need for a subsequent base rate case after the credit is fully amortized. Witness McLeod testified that this approach returns the credit to customers in an efficient and timely manner, and is equitable to both the Company and customers.

Witness McLeod proposed to include capital savings associated with the regulatory liability until the liability is fully returned to customers. According to witness McLeod, the capital savings decline as the regulatory liability is credited to customers over the two-year period; therefore, the revenue requirement during the first year is greater than the revenue requirement in the second year. Witness McLeod discussed the Company's methodology for determining the North Carolina jurisdictional EDIT to be refunded to customers based on a retrospective analysis of the methodologies approved by the Commission for allocating deferred North Carolina SIT expense in DNCP's previous base rate cases.

With respect to the level of SIT expense included the base non-fuel revenue requirement, witness McLeod proposed an accounting adjustment to reduce NC SIT expense for ratemaking purposes based on an apportioned NC SIT rate that includes a 4% statutory rate.

In direct testimony, Company witness Haynes proposed to allocate the Rider EDIT credits to customer classes based upon North Carolina rate revenue for 2015. Witness Haynes developed a decrement rate based upon actual 2015 kWh sales to be applied to each customer's 2015 sales. The total credit amount for each customer will be amortized over 12 months and provided through a monthly bill credit.

Public Staff witness Fernald testified regarding the history of HB 998, noting that it also added a new section, G.S. 105-130.3C, to the General Statutes concerning possible future rate reduction triggers. On August 4, 2016, the North Carolina Department of Revenue announced that pursuant to G.S. 105-130.3C, the corporate tax rate for tax years beginning on or after January 1, 2017, will be reduced from 4% to 3%. Witness Fernald testified that there are no restrictions on how EDIT should be refunded to ratepayers, and explained that the Public Staff believes that the manner in which EDIT should be refunded to ratepayers, including the period over which the EDIT is amortized, should be determined on a case-by-case basis in each utility's next general rate case. In this particular case, witness Fernald explained, in addition to the need for EDIT collected from past ratepayers to be returned to future ratepayers, there are several deferrals, which represent costs incurred to provide service to past ratepayers that will now be recovered from future ratepayers.

In this case, Public Staff witness Fernald proposed an EDIT regulatory liability of $15,708,000, which included the additional EDIT related to the decrease in the tax rate from 4% to 3% that was announced on August 4, 2016. She identified several regulatory assets and liabilities whose amortizations end in 2017, and proposed re-amortizing the unamortized balances for these assets and liabilities, since these amortizations will end in 2017 and will not continue on an ongoing basis. The total deferred costs and unamortized balances for regulatory assets and liabilities with amortizations ending in 2017 to be recovered from North Carolina ratepayers in this proceeding, as recommended by Public Staff witness Fernald in her testimony, are as follows:

Deferred Costs	Total Cost to be Recovered from NC Ratepayers
Warren County CC Deferral	$10,204,000
Brunswick County CC Deferral	2,957,000
Chesapeak Closure Costs	1,504,000
North Branch Net Proceeds/Costs	175,000
Unamortized Balances	
Unamortized Desighn Basic Costs - Surry	39,000
NUG Buyout Costs - Atlantic	104,000
NUG Buyout Costs - Mecklenburg	481,000
Bear Garden Deferral	593,000
DOE Settlement	(565,000)
Total per Public Staff	$15,492,000

Public Staff witness Fernald testified that both the EDIT liability and the deferred costs and unamortized balances listed above represent revenues collected or costs incurred in providing service to past ratepayers that will now be returned to or recovered from future ratepayers. Consequently, witness Fernald recommended that, instead of a decrement rider as proposed by the Company, the refund of the EDIT liability should be treated in the same manner as the recovery of these deferred costs and unamortized balances based on the circumstances in this proceeding. Therefore, witness Fernald recommended that both the EDIT liability and the deferred costs and unamortized balances listed above be included in the cost of service through a levelized amortization. Since the difference between the impact on rates of amortizing the EDIT liability and the deferrals and unamortized balances over three years and the impact of amortizing them over five years is not substantial, witness Fernald recommended that the levelized amortization of the EDIT liability and deferred costs and unamortized balances listed above be amortized over a three-year period using the after-tax rate of return recommended by the Public Staff in this proceeding.

With respect to the level of SIT expense included the base non-fuel revenue requirement, Public Staff witness Fernald proposed accounting adjustments to reflect the reduction in the North Carolina corporate tax rate from 4% to 3% effective for taxable income on or after January 1, 2017.

Public Staff witness Floyd testified that he recommended the Commission reject DNCP's proposed Rider EDIT. Witness Floyd stated that the Public Staff is concerned that although the EDIT was collected from customers over many years, that it will only be repaid to those who were customers during 2015. Witness Floyd testified that he believed witness Fernald's approach to the EDIT credit to be best as it returns the EDIT to all customers and removes the need for a Rider.

In rebuttal testimony, Company witness Stevens testified that a decrement rider provides greater precision in order to demonstrate to multiple constituents – the Commission, North Carolina customers, and the North Carolina General Assembly – that the amount to be refunded did in fact get refunded. Witness Stevens testified that a decrement rider provides greater transparency on the EDIT refund to North Carolina customers. DNCP's decrement rider approach, according to witness Stevens, is preferable because it credits the EDIT back to North Carolina customers more quickly in two years compared to the Public Staff's recommended three years.

Company witness McLeod accepted the total EDIT regulatory liability of $15,708,000 presented by Public Staff witness Fernald. Witness McLeod also accepted the Public Staff's recommendation to calculate the EDIT regulatory liability amortization on a levelized basis using an annuity factor. These changes were reflected in the Rider EDIT credit amounts presented in witness McLeod's rebuttal schedules and exhibits. Witness McLeod also accepted witness Fernald's accounting adjustments to reduce the level of NC SIT expense in the base non-fuel revenue requirement to reflect the reduction in the NC corporate tax rate from 4% to 3% effective for taxable income on or after January 1, 2017.

With respect to Rider EDIT, Company witness Haynes proposed that after Year 1, any over or under-recovery of the credit amount should be deferred and added (or subtracted) as appropriate from the Year 2 credit amount. Such amount should be allocated based upon the annualized revenue in witness Haynes' rebuttal exhibits. Witness Haynes proposed that prior to the tenth month from the effective date of the Year 2 rider, DNCP will provide an analysis to the Public Staff to evaluate if the total rider credit will be provided at the end of Year 2. For any deviation between the total rider credit and the projected credit provided to customers, the Company and the Public Staff will work together to develop an adjustment to the Rider EDIT to minimize the deviation over the remaining months of Rider EDIT being in effect.

The Stipulation provides that the appropriate level of EDIT to be refunded to customers in this case is $15,708,000 (on a pre-tax basis), which includes EDIT associated with the January 1, 2017, reduction in the North Carolina corporate state income tax rate from 4% to 3%. DNCP shall implement a decrement rider, Rider EDIT, as described in the rebuttal testimony of Company witnesses McLeod and Haynes, to refund EDIT to customers over a two-year period on a levelized basis, with a return. As shown on Settlement Exhibit IV, the appropriate amount to be credited to customers is

$16,816,000, which should be credited to customers via a rate that is calculated using the sales shown in Column 1 of Company Rebuttal Exhibit PBH-1, Schedule 11.[5]

Further, pursuant to Section 2.4.(a) of Session Law 2015-6, the Commission must adjust the rate for the sale of electricity, piped natural gas, and water and wastewater service to reflect all of the tax changes as enacted in HB 998. Under G.S. 105-130.3C, as enacted in HB 998, an automatic reduction in the State corporate income tax rate from 4% to 3% will become effective for the taxable year beginning on or after January 1, 2017, because certain net General Fund tax collection levels were met for the State's fiscal year 2015-2016. The base non-fuel rate revenue requirement in the Stipulation appropriately reflects the 3% NC SIT rate effective for the taxable year beginning on or after January 1, 2017.

The Commission finds and concludes that for the present case the ratemaking treatment of the EDIT regulatory liability presented in the Stipulation is just and reasonable to all parties in light of all the evidence presented. The Commission also finds and concludes that the base non-fuel rate revenue requirement in the Stipulation reflects the 3% NC SIT rate effective for the taxable year beginning on or after January 1, 2017.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The evidence supporting this finding of fact and these conclusions is contained in the verified Application, the Stipulation, the testimony and exhibits of the DNCP and Public Staff witnesses, and the entire record in this proceeding.

In the Company's Application, Company witness McLeod requested Commission approval of a levelization methodology on its books and records for its nuclear refueling and maintenance outage expenses. Witness McLeod testified that DNCP operates four nuclear units: two units at Surry and two units at North Anna. The Company utilizes a "3/3/2" planning practice for scheduling nuclear outages, meaning the Company performs three outages in two successive years, then two outages every third year.

According to witness McLeod, the Company incurs substantial outage costs during the refueling outages, and absent the levelization accounting treatment on its books and records, DNCP experiences and will continue to experience significant variability in its annual operating costs which causes the cost of service for one year to appear inconsistent with a previous year. DNCP requested approval of a levelization methodology in order to minimize this variability and to better match the refueling outage expenses with the period over which the benefit is realized. Witness McLeod stated that this request for accounting authority is not intended to modify the Company's existing approach to levelizing nuclear outage expenses for ratemaking purposes. Witness McLeod noted that the Commission approved similar accounting treatment in the most

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[5] On October 19, 2016, the Company filed proposed Rider EDIT to be implemented on November 1, 2016. The Rider EDIT rates for each customer class are identified on pages 129 and 260 of the Company's October 19 filing, and the supporting workpapers are included on page 291.

recent general rate case proceedings for Progress Energy Carolinas, now Duke Energy Progress (DEP) and Duke Energy Carolinas (DEC).[6]

Witness McLeod testified that under this accounting methodology, costs incurred during the three months leading up to an outage, costs incurred during the typical two-month outage period, and trailing costs incurred during the three months after an outage are deferred to a regulatory asset account. The deferrals are amortized over the period of the operating cycle between scheduled refueling for the unit, not to exceed 18 months. Amortization begins the month following completion of the outage and adjustments are made for trailing costs.

Public Staff witness Fernald testified that the Company implemented deferral and amortization of nuclear refueling outage costs on its books in April 2014 pursuant to Virginia legislation. Prior to this change, the Company expensed nuclear refueling outage costs in the month that the costs were incurred. According to witness Fernald, the Company has accounted for nuclear refueling outage costs since April 2014 as follows:

(1) The costs related to nuclear refueling outages are recorded to the appropriate O&M expense account as incurred, as was done in the past.

(2) A credit is recorded to FERC Account 407.4 – Regulatory Asset Deferral O&M for the costs being deferred. When this credit is netted against the amount charged to O&M expense, the costs being deferred are in effect removed from the cost of service. The Company decided that costs eligible for deferral include incremental costs incurred three months prior to the outage, during the outage, and three months after the outage. Specific details regarding the types of incremental costs eligible for deferral are provided in Fernald Exhibit 3.

(3) The deferred costs are then amortized over the refueling cycle, not to exceed 18 months, and the amortization expense for the costs is recorded to FERC Account 407.3.

Witness Fernald explained that in prior rate cases, pro forma adjustments have been made to normalize nuclear refueling outage costs for DNCP. With levelized accounting, the costs reflected in the Company's financial statements will be consistent with the ratemaking treatment of the costs, according to witness Fernald. In future rate proceedings, the test period amounts produced by this levelized accounting method will be the starting point in determining normal nuclear refueling outage expenses, subject to appropriate ratemaking adjustments.

Witness Fernald testified that DNCP's nuclear refueling outage deferral window for nuclear refueling outage costs is a longer period of time than that used by DEC and DEP.

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[6] Order Granting General Rate Increase, Docket No. E-2, Sub 1023 (May 30, 2013), Finding of Fact No. 31, and Order Granting General Rate Increase, Docket No. E-7, Sub 1026 (Sept. 24, 2013), Finding of Fact No. 36.

Witness Fernald testified that the accounting procedures established by DNCP are used for regulatory purposes in Virginia, and the Public Staff does not believe that the difference in the nuclear refueling outage deferral window necessitates the time and effort required to maintain a different accounting treatment for North Carolina. Public Staff witness Fernald emphasized that the amounts to be recovered for nuclear refueling outage costs are always subject to review in North Carolina rate cases.

Witness Fernald recommended approval of the Company's levelized accounting treatment with the following conditions:

> (1) The regulatory asset associated with the nuclear refueling outage deferral accounting will not be included in rate base in rate cases. The Company has made an adjustment in this proceeding to remove the nuclear refueling outage deferral balance in regulatory assets from rate base.
>
> (2) Under the Virginia legislation, the amortization period is to be no more than 18 months. The amortization period should be consistent with the refueling cycle of the nuclear units, which currently is 18 months. If DNCP changes the frequency of the refueling cycle for any of its nuclear units in the future, the amortization period for the deferral accounting should be changed to reflect the change in the refueling cycle.

Nucor witness Kollen testified that the change in accounting would result in a one-time reduction in maintenance expense. The Company's proposal will delay the nuclear outage expense for accounting purposes by approximately 18 months to reflect the fact that the costs will be deferred when incurred and then amortized to expense over the period between outages instead of being expensed when incurred. According to witness Kollen, if this accounting is authorized by the Commission, the Company's nuclear outage expense will be reduced when each of the next four outages occur, in other words, there will be a one-time savings in O&M expense. Witness Kollen contended that the Company would retain the one-time savings if the Commission does not direct the Company to defer and amortize the savings as a reduction to expense for ratemaking purposes.

Witness Kollen proposed that the Commission adopt the change in accounting for ratemaking purposes, subject to a deferral and amortization of the one-time savings in expense.

In rebuttal testimony, Company witness Stevens testified that Nucor witness Kollen mischaracterized the financial impacts of implementing the nuclear outage levelization accounting methodology on DNCP's books and records. Witness Stevens argued that the new accounting methodology did not change the cost of nuclear outages. Operating expense in the period was reduced when this accounting methodology was first implemented. However, this was not a "one-time savings," but instead a timing difference resulting from implementation of a new accounting methodology.

Witness Stevens argued that witness Kollen's proposal to establish a regulatory liability for nuclear outage expenses is inappropriate as nuclear outage costs are a component of the base non-fuel rate cost of service, and the Company is not recovering these costs dollar for dollar. According to witness Stevens, an analysis demonstrates that the incurred costs in the past few years are greater than the normalized level of nuclear outage costs approved by the Commission in its 2012 Rate Case. The Company incurred system level average costs for this period of $83.680 million compared to the system level costs included in base rates of $78.163 million. Therefore, witness Stevens concluded that there are no one-time savings or windfalls as suggested by witness Kollen.

The Stipulation provides that the Company may use levelized accounting for nuclear refueling costs, as described in the testimony of Public Staff witness Fernald.

The Commission concurs with DNCP and the Public Staff that implementing this nuclear levelization accounting methodology should have no ratemaking implications, contrary to the proposal set forth by witness Kollen. Accordingly, the Commission finds and concludes that Nucor witness Kollen's proposal to establish a regulatory liability for purported one-time savings associated with establishment of the nuclear outage levelization accounting methodology is inappropriate. The implementation of a new accounting methodology for nuclear outage costs does not change the underlying nature and amount of nuclear outage costs incurred by the Company. The Commission further finds and concludes that DNCP's request to implement levelization accounting for nuclear outage and refueling expenses, as set forth in the Stipulation, is hereby granted.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 16-18

The evidence supporting these findings of fact and conclusions is contained in the verified Application, the testimony and exhibits of Company witnesses Curtis, Hevert, Mitchell and McLeod, Nucor witness Kollen, and Public Staff witness Maness, the Stipulation, and the entire record in this proceeding.

DNCP witness Curtis testified that DNCP's coal combustion residual (CCR) expenditures are the result of efforts by DNCP to comply with the United States Environmental Protection Agency's (EPA's) Standards for Disposal of Coal Combustion Residuals in Landfills and Surface Impoundments (CCR Final Rule), which became effective for DNCP on April 7, 2015.

DNCP witness Mitchell testified that the Virginia Department of Environmental Quality incorporated the CCR Final Rule into its solid waste management regulations in December 2015. He stated that DNCP is developing comprehensive closure and storage plans for the CCR impoundments located at DNCP's operating and non-operating coal plants. Witness Mitchell discussed the Company's plans to close or retrofit the ash ponds and landfills at Chesapeake, Yorktown, Chesterfield, Clover, Mt. Storm, Bremo, and Possum Point Power coal-fired generating stations. He testified that the pond and landfill closures or retrofits are in response to the CCR Final Rule regulating the management of CCR stored in ash ponds and landfills. Witness Mitchell explained that the CCR Final

Rule establishes environmental compliance requirements for the disposal of CCR, and provides specifications for construction and closure of CCR ponds and landfills. In addition, witness Mitchell testified that these new regulations also impose higher requirements in the areas of structural integrity standards, public disclosure, location restrictions, inspection, groundwater monitoring and cleanup for existing and new CCR ponds and landfills.

In direct testimony, Company witness McLeod testified that the enactment of the CCR Final Rule created a legal obligation to retrofit or close all inactive and existing ash ponds over a certain period, as well as to perform required monitoring, corrective action, and post-closure care activities as necessary. Witness McLeod explained that the Company recognized ARO liabilities of $385.7 million on a total system basis during the test year for financial reporting purposes in accordance with Accounting Standard Codification (ASC) 410-20 (formerly Statement of Financial Accounting Standard No. 143) related to future ash pond and landfill closure costs. Witness McLeod testified that the Company eliminates all the effects of ARO accounting pursuant to ASC 410-20 from the cost of service, including the AROs associated with the CCR Rule, in accordance with the Commission's directives in Docket No. E-22, Sub 420. Witness McLeod proposed to defer the actual North Carolina jurisdictional CCR-related cash expenditures incurred through the update period in this case (June 30, 2016) to be amortized over a three-year period commencing with rates approved in this case effective November 1, 2016.

DNCP witness McLeod further testified that the CCR Final Rule requires DNCP to close or retrofit all of its active and inactive coal ash ponds and landfills. He stated that DNCP has eight generating facilities where coal ash remediation must be performed. In his direct testimony, witness McLeod testified that DNCP spent $37.5 million during the test period and anticipated spending an additional $63.8 million through June 2016. He testified that DNCP proposes to defer its portion of the expenditures over a three-year period.

In his supplemental testimony, witness McLeod adjusted the updated January 2015 through June 2016 CCR costs to a total of $84.4 million. He testified that DNCP proposes to establish a regulatory asset in the amount of $4.3 million, North Carolina's allocable share of the CCR costs to date, and to amortize this amount over a three-year period beginning with the effective date of the rates set in this proceeding.

Public Staff witness Maness testified that the Public Staff generally agrees with the concept proposed by the Company of deferring and amortizing the costs incurred through June 30, 2016, over a multi-year period, but does not necessarily agree that this treatment is automatically mandated by the August 6, 2004, Order Allowing Utilization of Certain Accounts in Docket No. E-22, Sub 420 (2004 ARO Order). Witness Maness also disagreed with the Company's proposed three-year amortization period and instead proposed a 10-year amortization. According to witness Maness, the majority of the costs underlying the ARO liability, and thus current and future expenditures, are related to generating assets that have already been retired or are financially impaired and are soon to be retired. He testified that for costs of significant size related to retired or abandoned plants, the Public Staff in recent years has consistently recommended an amortization or levelization period of 10 years, and this period has been approved by the Commission.

In addition, Public Staff witness Maness testified regarding some of the specific CCR work being performed by DNCP, as described by DNCP in response to data requests. Witness Maness stated that four of the DNCP coal-fired facilities are closed, or have been converted to natural gas-fired facilities. At the closed facilities, remediation is taking three different forms: (1) cap and close method; (2) a clean and close method in which the coal ash is moved to an on-site pond that is being capped and closed, and the original impoundment is closed; or (3) the clean and close method, except the original impoundment is used for a new purpose. With regard to operating coal facilities, witness Maness stated that DNCP's work at this point is mainly project planning and engineering.

Witness Maness testified that the Public Staff investigated DNCP's CCR remediation efforts and found that the efforts and costs were prudent and reasonable. He stated that DNCP incurred $84.4 million in cash expenditures for CCR remediation from January 2015 through June 2016. He also provided DNCP's projected CCR costs during the next several years. That amount was filed by DNCP under seal as a confidential trade secret. Witness Maness testified that DNCP has recorded this amount, adjusted to its current fair value, as an ARO. The present amount of the ARO recorded on DNCP's financial statements is $326 million. As these costs are incurred and deferred into a regulatory asset account, that amount will be deducted from the ARO.

With respect to the ongoing deferral of CCR expenditures, witness Maness indicated that the Company plans to defer North Carolina jurisdictional CCR cash expenditures for review by the Commission in future base rate proceedings, and subsequent recovery through base non-fuel rates approved in such proceedings. Witness Maness contended, however, that it was clear from the language of the 2004 ARO Order that the Commission intended that the authorization granted by the Order would have no impact on the ratemaking treatment to be determined by the Commission. He stated that although the 2004 ARO Order could be read as applying to all AROs, it should be noted that at the time of its issuance, the only significant ARO in existence was the one established for nuclear decommissioning. At that time, the Commission already had in place a long-standing, comprehensive mechanism to provide for the tracking and recovery of nuclear decommissioning costs. Witness Maness testified that the purpose of the 2004 ARO Order was to maintain Company accounting to match the Commission’s longstanding accounting and ratemaking treatment of those costs, consistent with the statement in the ARO Order that “the intent and outcome of the deferral process shall be to continue the Commission’s currently existing accounting and ratemaking practices.” However, in the case of CCR expenditures, witness Maness testified that the Commission has not yet decided what the long-standing accounting and regulatory treatment of those costs should be. Therefore, in the absence of any action by the Commission in this case, witness Maness stated that continuing “the Commission’s currently existing accounting and ratemaking practices,” as the 2004 ARO Order requires, would most likely mean that the CCR expenditures through June 30, 2016, and afterwards, would simply be written off to expense in the year incurred. Witness Maness testified that because no prior

Commission treatment of CCR costs has been determined, the Company could not simply unilaterally presume that its proposed ratemaking deferral is authorized. Nonetheless, witness Maness testified that in this proceeding the Public Staff has investigated the CCR expenditures that the Company has proposed to defer and amortize, and has determined that the costs were reasonable and prudently incurred. Therefore, the Public Staff recommended the establishment of a regulatory asset for those expenditures.

Given the above, witness Maness made several recommendations regarding ongoing CCR deferrals:

> (1) That the Company be allowed to defer additional CCR expenditures through calendar year 2018, without prejudice to the right of any party to take issue with the special accounting treatment in a regulatory proceeding.
>
> (2) That the Commission note in its order in this proceeding that it is not making any conclusions regarding the prudence and reasonableness of the Company's overall CCR plan, or regarding any specific expenditures other than the ones it has approved for recovery in this case.
>
> (3) That the annual amortization expense approved for recovery in this proceeding continue to be credited as an offset to any future deferrals recorded by the Company, up until the time rates approved in the Company's next general rate case go into effect. Additionally, any other appropriate credits related to CCR expenditures, such as recoveries from third parties or governmental authorities, should be recorded as an offset to any future deferrals.
>
> (4) That the Company be required to file an annual report with the Commission, on the same date it files its annual FERC Form 1 report, detailing the CCR deferrals recorded in the previous calendar year as well as the annual amortization offset and any other offsets recorded.
>
> (5) That because CCR costs are being incurred due to the nature of the coal burned to produce energy over the years, the energy allocation factor be used to determine the North Carolina retail revenue requirement.

Moreover, Public Staff witness Maness testified that, during its investigation in this proceeding the Public Staff became aware that the Company has been or is involved in several legal disputes with various parties regarding its CCR compliance activities or the state of its CCR facilities. Additionally, witness Maness explained that the Company remains subject to possible state and federal findings of non-compliance with applicable statutes and regulations. Witness Maness indicated that the Public Staff has not become aware of any significant costs that have been incurred to date as a result of these disputes. Nevertheless, the Public Staff recommended that the Commission include in its order in this proceeding, in association with any approval of future deferral, a finding that any costs resulting from fines, penalties, other imprudent or unreasonable activities, or corrective actions to address those activities, are not allowable for deferral or recoverable for ratemaking purposes, and that legal costs incurred or settlements reached in resolution of disputes will be subject to close scrutiny to make sure that they are reasonable and appropriate for recovery from ratepayers.

Nucor witness Kollen testified that a three-year amortization period is unduly and unnecessarily short. Witness Kollen explained that a reasonable amortization period for the inactive and retired plants is 10 years, and a reasonable amortization period for the operating plants is the remaining life of each plant. The remaining service lives for the operating plants, according to witness Kollen, range from six to 35 years. Witness Kollen estimated an approximate amortization period based on the remaining service lives of 20 years. For the combined CCR costs of DNCP's retired and operating plants, witness Kollen proposed a 15-year amortization period for all CCR deferrals. Nucor reiterated this position in its post-hearing Brief.

In rebuttal testimony, Company witness Stevens argued that a lengthy recovery period for regulatory assets does not serve the best interests of DNCP's North Carolina customers or the Company. Since the Company is afforded a return on the unamortized balance for ratemaking purposes, witness Stevens argued that a longer amortization period costs customers more in the long run, while delaying the Company's recovery of actually incurred costs in the short run. Witness Stevens contended that delaying recovery of these actually incurred costs produces greater rate instability, and the Company's position strikes a reasonable balance of establishing rates that send accurate price signals to North Carolina customers, while recognizing the appropriate level of cost of service. The Company's proposed non-fuel base revenue increase in this proceeding, according to Stevens, is almost completely offset by a 2017 fuel factor reduction and decrement rider to refund EDIT with the total overall change in North Carolina retail rates approximating 0.2%. Witness Stevens noted that for many customer classes, their bills would reflect an overall decrease in rates on January 1, 2017.

With respect to Nucor witness Kollen's proposal to amortize CCR expenditures over 15 years, witness Stevens explained that the Company anticipates significant additional CCR expenditures subsequent to June 30, 2016, and a short duration for the amortization of this first wave of CCR expenditures is more appropriate. Witness Stevens contended that the Company's position aligns well with the fuel factor reduction and the significant EDIT refund, and setting an appropriate amortization level for this first wave of CCR expenditures allows for greater rate stability when addressing the need to recover additional phases of ongoing CCR compliance in future rate filings.

With respect to Public Staff witness Maness' proposal to amortize CCR expenditures over 10 years, witness Stevens argued that the comparison of the CCR expenditures to the abandonment or impairment and early retirement of a generating facility is neither reasonable nor accurate. Witness Stevens testified that the abandonment or impairment and retirement of a generating facility is a one-time, non-recurring event, while CCR expenditures are recurring and are environmental compliance and remediation costs, not abandoned plant, that will need to be recognized in future rate filings. According to witness Stevens, the Public Staff's proposal will likely result in overlapping vintages of CCR expenditure regulatory asset amortizations in future rate cases. To the contrary, witness Stevens explained that under the Company's proposal, the regulatory asset from the instant proceeding will conclude and be replaced by the next regulatory asset in the next general rate case, allowing for a more smooth transition from one case to the next, and more importantly, achieving greater rate stability for customers.

With respect to witness Maness' discussion regarding the Company's proposed ratemaking treatment of CCR expenditures, Company witness McLeod explained in his rebuttal testimony that the Company has set forth a ratemaking methodology for CCR expenditures in this case, and the Public Staff and other parties have the opportunity to respond. Witness McLeod testified that no one is disputing that the Commission will ultimately rule on the Company's proposed ratemaking methodology for CCR expenditures.

In addition, witness McLeod testified that the Company already requested and the Commission has already granted deferral authority for CCR expenditures in the 2004 ARO Order, and it is not necessary for the Company to request deferral authority from the Commission again for ARO costs beyond 2018 as recommended by Public Staff witness Maness. With respect to witness Maness' recommendation for the Commission to note in its order in this proceeding that it is not making any conclusions regarding the prudence or reasonableness of the Company's overall CCR plan, or regarding specific expenditures other than the ones it has approved for recovery in this case, witness McLeod argued that it is not necessary for the Commission to address future CCR expenditures in this proceeding. Further, witness McLeod disagreed with witness Maness' recommendation for the annual amortization expense approved for recovery in this proceeding continue to be credited as an offset to any future deferral recorded by the Company, up until the time rates approved in the Company's next general rate case go into effect, stating that the Company is not recovering these costs dollar for dollar, they are simply part of the total base non-fuel rate cost of service. Witness McLeod stated that it would be no more appropriate to grant witness Maness' proposal for these costs than it would for any other cost in the base non-fuel cost of service. Witness McLeod also contended that it is not necessary or appropriate for the Commission to address the future ratemaking treatment of fines, penalties, or other litigation costs in this case.

Finally, witness McLeod indicated that the Company accepted the Public Staff's adjustment to calculate the CCR expenditures regulatory asset by the energy factor.

The Stipulation includes the following provisions with respect to CCR costs:

(1) Amortization periods – CCR expenditures incurred through June 30, 2016, should be amortized over a five-year period. 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.

(2) Deferral of future CCR expenditures – By virtue of the Commission's approval in this proceeding of a mechanism to provide for recovery of CCR

expenditures incurred through June 30, 2016, the Company has authority pursuant to the August 6, 2004, Order in Docket No. E-22, Sub 420, to defer additional CCR expenditures, without prejudice to the right of any party to take issue with the amount or the treatment of any deferral of ARO costs in a rate case or other appropriate proceeding.

(3) Continuing amortization and deferral of CCR expenditures – The Company and the Public Staff reserve their rights in the Company's next general rate case to argue to the Commission (a) how the unamortized balance of deferred CCR expenditures incurred by the Company prior to June 30, 2016, and the related amortization expense should be addressed; and (b) how reasonable and prudent CCR expenditures incurred by the Company after June 30, 2016, should be recovered in rates.

(4) Overall prudence of CCR Plan – The Public Staff's agreement in this proceeding to the deferral and amortization of CCR expenditures incurred through June 30, 2016, shall not be construed as a recommendation that the Commission reach any conclusions regarding the prudence and reasonableness of the Company's overall CCR plan, or regarding any specific expenditures other than the ones to be recovered in this case.

(5) Reporting - The Company shall file with the Commission, on the same date it files its quarterly ES-1 report, a report detailing 1) the CCR deferrals recorded in the reporting period, and 2) regulatory accounting entries pursuant to the August 6, 2004, Order in Docket No. E-22, Sub 420, with regard to any costs other than nuclear decommissioning costs or CCR costs, recorded in the reporting period.

(6) That DNCP agrees to provide the Public Staff, within 90 days of the date of the Stipulation, with a presentation regarding its accounting practices for non-nuclear asset retirement obligation costs.

At the hearing, witness Maness testified that the Stipulating Parties had reached agreement as to the CCR issues set forth in his testimony. He also stated that the Company and Public Staff agreed that it was not necessary for the Commission to make any findings regarding the possible future treatment of fines, penalties, or other litigation costs in this proceeding.

Further, witness Maness testified that the Public Staff's general impression is that DNCP's CCR repository facilities "were constructed and operated in a similar manner to facilities in various areas in the country." (T Vol. 8, at p. 361) In addition, witness Maness elaborated on the Public Staff's investigation of DNCP's CCR remediation efforts. He testified that the effort thus far has been engineering studies for work to be performed at the various sites, and beginning the closure of existing impoundments, such as dewatering of CCRs and water treatment. Witness Maness further testified that the Public Staff's Engineering Division reviewed invoices for the CCR work performed by DNCP and did not find any of the costs to be unreasonable.

On November 16, 2016, the Attorney General's Office (AGO) filed a post-hearing Brief. The AGO takes the position that the proposed recovery of coal ash expenditures unfairly burdens consumers and should be rejected by the Commission. The AGO notes that the Commission must set rates that are fair to the ratepayers and utility, pursuant to G.S. 62-133(a), and that the burden of proof is on the utility, under G.S. 62-75. The AGO further states that the Commission should consider, among other things, whether the CCR costs incurred are reasonable and prudent, and that this determination is detailed and fact specific, especially in the context of complicated cost recovery for environment-related clean-up costs. In addition, the AGO states that DNCP's CCR costs are projected to increase significantly over the next two or three years.

Moreover, the AGO contends that DNCP's CCR expenditures do not relate to operations that are used and useful for DNCP's current customers because they are for the disposal of CCRs that were produced over decades at plants that no longer generate electricity. Further, the AGO maintains that DNCP's proposal to include the unamortized balance of CCR costs in DNCP's rate base and earn a return on the unamortized balance is not a fair or lawful burden to impose on ratepayers, and is contrary to the holding in State ex rel. Utilities Comm'n. v. Carolina Water Service, 335 N.C. 493, 439 S.E.2d 127 (1994).

In addition, the AGO asserts that DNCP failed to provide detailed evidence about whether the CCR remediation costs it seeks to recover are reasonable and prudent, and that the Public Staff's analysis was insufficient. According to the AGO, DNCP appears to simply rely on compliance with the CCR Final Rule to justify its recovery of costs. The AGO also points out that DNCP has been sued for alleged violations of CCR environmental regulations.

Discussion and Decision

Prudence and Reasonableness

In the Coal Ash Management Act of 2014, the General Assembly included a moratorium prohibiting the Commission from allowing CCR clean-up costs in a utility's base rates. The moratorium was in effect until January 15, 2015. However, that section also states that "Nothing in this section prohibits the utility from seeking, nor prohibits the Commission from authorizing under its existing authority, a deferral for costs related to coal ash combustion residual surface impoundments." G.S. 62-133.13.

DNCP, like many electric utilities in the United States, has for decades generated electricity by burning coal. During those decades, the widely accepted reasonable and prudent method for handling CCRs has been to place them in coal ash landfills or ponds (repositories). At the hearing in this docket, in response to questions by the Commission, DNCP witness Stevens testified that when the EPA issued its draft CCR Rule in December 2014, DNCP first began addressing the fact that its CCRs could not remain stored in their existing repositories in perpetuity. Further, as discussed above, in his direct testimony, DNCP witness McLeod testified that the CCR Final Rule requires DNCP to close or retrofit all of its active and inactive CCR repositories. He further testified that

DNCP spent $37.5 million during the test year and anticipated spending an additional $63.8 million through June 2016. He later filed supplemental testimony adjusting the updated January 2015 through June 2016 CCR costs to a total of $84.4 million.

Public Staff witness Maness testified that the Public Staff's general impression is that DNCP constructed and operated its CCR repositories in a manner that is similar to CCR facilities in various areas of the United States. He stated that four of the eight DNCP coal-fired facilities are closed, or have been converted to natural gas-fired facilities. At the closed facilities, DNCP is using three methods in its effort to comply with the CCR Final Rule: (1) cap and close method; (2) a clean and close method in which the coal ash is moved to an on-site pond that is being capped and closed, and the original repository is closed; or (3) the clean and close method, except the original repository is used for a new purpose. He described the efforts as engineering work at various facilities, and the beginning of closure work at some facilities, including dewatering of the ash ponds and water treatment. Witness Maness also testified that the Public Staff Engineering Division reviewed the invoices for the CCR work that has been performed by DNCP thus far, and that the Public Staff did not find that any of DNCP’s CCR costs were unreasonable. Witness Maness testified that the Public Staff found that DNCP's efforts and costs expended were prudent and reasonable.

Based on the allocation methodology agreed upon in the Stipulation, DNCP's allocable share of the CCR costs is $4,417,000. The Stipulating Parties agreed to DNCP's requested deferral of these costs and an amortization period of five years.

The Commission finds the CCR testimony of DNCP witnesses Stevens and McLeod and Public Staff witness Maness to be credible and to constitute substantial evidence that DNCP's actions in planning and beginning the work for permanent CCR repositories have been prudent, and that the CCR remediation costs incurred thus far by DNCP are reasonable. In particular, the Commission gives substantial weight to Public Staff witness Maness's testimony describing the Public Staff’s investigation of DNCP’s CCR remediation efforts. Witness Maness testified in some detail regarding the three CCR remediation options being employed by DNCP. He also testified that the Public Staff found that DNCP's CCR remediation efforts and costs were prudent and reasonable.

The AGO takes issue with the probative value of the DNCP and Public Staff evidence in support of CCR remediation costs recovery, not with the absence of such evidence. As outlined in detail above, the record contains substantial, unrebutted evidence from DNCP and Public Staff witnesses that DNCP’s CCR remediation expenditures at issue were reasonable and prudent. The AGO has offered no witness or other probative evidence that DNCP’s incurrence of CCR remediation costs were imprudent or unreasonable. No witness offered evidence that the costs should not be recovered. The only material dispute among the witnesses was over the appropriate amortization period for deferred remediation costs.

The AGO contends that DNCP's CCR activities have not produced property that is used and useful for DNCP's ratepayers. The Commission does not agree and determines that the used and useful argument misses the point. The AGO’s argument is based on the fact that some of the coal-fired generating plants producing CCRs were no longer in service or were converted to gas-fired generation or some of the coal ash repositories had been closed before the test year. The Commission finds the AGO's logic misplaced. Due to federal and state environmental regulations, and in an attempt to remediate potential environmental degradation, DNCP incurred expense in the test year as extended. The fact that some of the coal-fired plants from which the CCRs had been removed were no longer in service or that the repositories in which the CCRS were stored had been closed and no longer receiving CCRs is beside the point. The issue is not recovery of costs of closed plants or costs of storing CCRs in repositories over past periods. The issue is recovery of remediation costs incurred in the test year as extended. In addition, a number of the electric generating plants from which CCRs are being and have been produced and the repositories are still in operation and have not been taken off line or closed.

Moreover, the current CCR repositories are and have served their purpose of storing CCRs for many years. In that respect, they have been used and useful for DNCP's ratepayers. However, pursuant to the CCR Final Rule, DNCP must incur expenses to the existing repositories for environmental remediation. As a result, the required solution for the CCR remediation serves the public policy of encouraging and promoting harmony between public utilities, their users and the environment. See G.S. 62-2(a)(5). Based on the testimony of witnesses Stevens, McLeod, and Maness, DNCP is responding to the CCR Final Rule requirements in a responsible and prudent manner. The result of DNCP's efforts should be the expenditure of funds to establish permanent CCR storage repositories. Like the existing CCR repositories, these permanent storage repositories will be used and useful for DNCP's ratepayers.

Further, the Supreme Court's decision in Carolina Water Service, cited by the AGO, does not support a denial of rate base treatment for the deferred and unamortized test year costs of CCR remediation. In Carolina Water Service, the Commission allowed the utility to include in the utility's rate base the unamortized portion of net costs still on the books at time of retirement not charged off in the test year for its Mt. Carmel wastewater treatment plant, even though the plant was not operating at the end of the test year and would never again be in service. The Commission's rationale was that the Mt. Carmel wastewater treatment plant unrecovered net costs should be treated as an extraordinary property retirement, with the deferred and unamortized costs included in the utility's rate base. The Supreme Court reversed that portion of the Commission's Order. The Court stated:

> [C]osts for abandoned property may be recovered as operating expenses through amortization, but a return on the investment may not be recovered by including the unamortized portion of the property in rate base.

Carolina Water Service, 335 N.C., at 508, 439 S.E.2d, at 142.

The issue in Carolina Water Service was whether to include in rate base the unamortized, unrecovered costs of a wastewater treatment plant that had been placed in service many years ago at which time the costs of the plant were incurred but with respect to plant that had been permanently retired. As addressed above, the costs at issue in this case are test year remediation costs, not unamortized costs of abandoned plants. Whatever costs DNCP incurred in past years in coal-fired generating plants already removed from service or costs incurred in the past to store CCRs in repositories now closed are not costs DNCP seeks to recover as DNCP's CCR remediation costs.

If, hypothetically, the Court had determined that costs Carolina Water Service had incurred in the test year to remediate potential environmental degradation from a discontinued wastewater treatment plant could be amortized but that the unamortized costs could not be included in rate base, perhaps such precedent would support the AGO's position; however, such costs are not those the Court addressed.

Although four of the coal-fired generating plants that are the sites of DNCP's CCR remediation efforts are no longer generating electricity, DNCP is not seeking to defer undepreciated costs of these plants or inclusion of unamortized costs in rate base as part of its CCR cost recovery request. Also, the existing CCR repositories at these sites cannot be abandoned by DNCP. Unlike the abandoned Mt. Carmel wastewater treatment plant in Carolina Water Service, the existing CCR repositories continue to be used and useful for storing CCRs, and will continue to be used and useful until DNCP moves the CCRs to a permanent repository, or takes the necessary steps to cap and close the existing repository.

The Commission's determination for allowing a portion of test year CCR costs to be recovered in this case is beneficial to DNCP, and the decision to amortize a large percentage of these test year CCR costs over a five-year period is a benefit to the ratepayer. The Commission likewise finds reasonable the provisions of the Stipulation allowing a return on the unamortized balance over the five-year period to be fair to the Company. Further, the Commission deems appropriate the establishment of a regulatory asset through which future CCR costs are accounted for, and thereby potentially departing from the general rule of matching future annual costs with revenues in the same period. In this fashion, the Company will have the opportunity to seek cost recovery for this unexpected and extraordinary cost expended in response to the CCR Final Rule which has required DNCP to store CCRs in a manner different from that in which the CCRs were being stored prior to 2015. The cost of complying with federal and state CCR remediation requirements was a risk that was unknown to the Company prior to 2015. Absent deferral, failure to recover those future costs could materially impact the Company's earnings. The Company's actions and testimony, and the testimony of Public Staff witness Maness, provide justification for the Commission's decisions. No witness testified against the effort to treat future CCR remediation costs as a regulatory asset for deferral and consideration in a future rate case. Based upon the entire evidence of record, the present Stipulation to allow the test year CCR costs to be recovered in this case by amortization over a five-year period with the unamortized balance to earn a return and the authorization to treat future CCR costs incurred through 2018 as a regulatory asset (which is the mechanism to facilitate the deferral of future CCR costs) is proper and in the public interest under the facts and circumstances of this case.

Conclusions on CCR Cost Deferral

Based on the foregoing and the record, the Commission finds and concludes that DNCP shall be allowed to defer the costs of its remediation of coal combustion residuals through June 30, 2016, and shall be allowed to amortize those deferred costs over a period of five years. The Company submitted substantial evidence that its costs incurred to comply with federal and state law regarding disposal of CCRs were prudently and reasonably incurred. No other party presented conflicting direct evidence on prudence or reasonableness of these costs. However, the Commission's approval of DNCP's CCR cost deferral is based on the particular facts and circumstances presented in this docket and, therefore, is not precedent for the treatment of CCR costs in any future proceedings.

In addition, the Commission finds and concludes that the treatment of CCR costs incurred by DNCP after June 30, 2016, shall be reviewed in a future rate case, subject to the provisions of the Stipulation regarding future amortization periods, deferral of future CCR expenditures, continuing amortization and deferral of CCR expenditures, and any other arguments or positions presented by the Company, the Public Staff, or another party at that time. Further, the Commission's determination in this case shall not be construed as determining the prudence and reasonableness of the Company's overall CCR plan, or the prudence and reasonableness of any specific CCR expenditures other than the ones deferred and authorized to be recovered in this case.

Finally, the Commission finds reasonable the provisions of the Stipulation regarding the agreement of DNCP to make a presentation to the Public Staff regarding its accounting practices for non-nuclear asset retirement obligation costs.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 19-23

The evidence supporting these findings of fact and conclusions is contained in the filings and Orders in Docket Nos. E-22, Sub 519, and Sub 533, the Company's verified Application, the direct and rebuttal testimony and exhibits of Company witnesses McLeod and Stevens, the testimony of Public Staff witness Fernald and Nucor witness Kollen, the Stipulation, and the entire record in this proceeding.

Warren County CC and Brunswick County CC Deferrals

The Company's initial Application proposed to amortize the deferred costs, including a return on investment, associated with the Warren County CC requested in the Company's petition in Docket No. E-22, Sub 519. [7] As explained by Company witness

[7] The Commission previously addressed the deferral costs related to the Warren County CC. On January 30, 2015, DNCP filed an application for an accounting order in Docket No. E-22, Sub 519 (Sub 519 docket) requesting that it be allowed to defer certain costs associated with its Warren County CC generating facility that was placed in service in December 2014. After comments by the parties and an oral argument held on June 15, 2015, the Commission issued an Order Denying Deferral Accounting for Warren County CC on March 29, 2016. DNCP filed for reconsideration regarding the deferral of the Warren County CC on March 3, 2016 (Motion for Reconsideration). On May 17, 2016, the Commission issued an Order

McLeod, DNCP requested to defer the incremental costs incurred from the time the assets were placed into service (December 2014) until the time they are reflected in the base non-fuel rates, and that these cost be amortized over a three-year period, with the unamortized balance, net of ADIT, included in rate base.

The initial Application also proposed to amortize the deferred costs, including a return on investment, associated with the Brunswick County CC requested in the Sub 533 docket, from the time the assets were placed into service (April 2016) until the time they are reflected in base non-fuel rates, and that these costs be amortized over a three-year period.

Public Staff witness Fernald testified that DNCP filed additional evidence concerning the Sub 519 docket. She stated that had DNCP filed this additional evidence concerning its December 2014 ES-1 information as part of its original deferral application, the Public Staff's position on the original deferral request would have changed. Witness Fernald further testified that while the Public Staff does not agree with all of the Company's additional adjustments to the December 2014 ES-1 included in its Motion for Reconsideration, the Public Staff would have agreed with the Company's proposed adjustment to apply the 2014 cost of service study factors to the December 2014 ES-1. Witness Fernald stated that with this adjustment, the ROE would have been materially below the Company's authorized ROE, and the Public Staff would not have opposed the Company's deferral request based on earnings. Therefore, Public Staff witness Fernald recommended that the Warren County CC deferral costs of $10,204,000 for North Carolina retail be recovered from ratepayers in this proceeding through a levelized amortization over a three-year period.

Nucor witness Kollen recommended that the Commission deny DNCP's proposed regulatory deferrals associated with the Warren County CC and Brunswick County CC. With respect to the Warren County CC deferral, witness Kollen discussed the Order Denying Deferral Accounting for Warren County Combined Cycle Generating Facility issued on March 29, 2016, in Docket No. E-22, Sub 519, in which the Commission denied the Company's deferral request. Witness Kollen noted the Commission subsequently agreed to rehearing on the issue in the instant proceeding.

According to witness Kollen, the Company's requests sought deferral of costs only through June 30, 2016. He argued that since that date now has passed, an accounting order issued after June 30, 2016, necessarily would authorize retroactive ratemaking.

Nucor witness Kollen noted that the Company did not seek to return to customers savings from the ODI implemented earlier in 2016. The Company proposes to recover increases in its costs (i.e. the Warren County CC deferral request), while at the same time

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consolidating the Motion for reconsideration for the Warren County CC deferral with the general rate case application filed in this docket. The Order also consolidated the Deferral Request for the Brunswick County CC, which was filed in Docket No. E-22 Sub 533 (Sub 533 docket) into the general rate case docket as well.

retain reductions in its costs. These proposals, according to witness Kollen, are inconsistent and inequitable.

Additionally, witness Kollen testified that any deferrals authorized for 2015 cannot and will not be recorded in 2015 and will not affect the Company's earnings in 2015, as the Company's accounting books now are closed and final for 2015. He stated that the ROE effect of the Brunswick County CC costs is approximately 0.08%, all else being equal, or approximately two months of the effect of Warren County CC. This is not material, according to witness Kollen, even if the Company is not earning its authorized return and does not meet this basic test applied by the Commission in the Warren County CC and other deferral proceedings. Nucor witness Kollen, therefore, recommended that the Commission reject the Company's request to defer and amortize these post-commercial operation costs.

In the event that the Commission authorizes deferral of these costs, witness Kollen recommended that the Commission levelize or annuitize the revenue requirement effect over a 10-year amortization period to include a return on and recovery of the regulatory asset. He testified that the post-commercial operation costs are analogous to "start-up costs" that could be amortized over the life of the unit. Witness Kollen argued that the Company's proposed three-year amortization period is unduly short and unnecessarily increases the revenue requirement compared to a longer amortization period.

In rebuttal testimony, Company witness Stevens testified that it is important for the Commission to fully assess a utility's request for deferral accounting with the evidence on the financial condition and earned return of the utility in question, as well as the impact that an extraordinary event has on that earned return and financial condition. In response to witness Kollen's testimony regarding the Commission's prior denial of the Warren County CC deferral request, witness Stevens contended that the extensive and detailed evidence presented in the Company's May 3, 2016, Motion for Reconsideration, filed in Docket No. E-22, Sub 519, demonstrates that DNCP's earned return for the 2015 test year was 5.99%. Witness Stevens testified that the financial impact of placing the Warren County CC in service is also significant and meets the Commission's well-established standard for deferral authorization, especially given the substantial fuel savings derived from the operation of the generation asset for the benefit of North Carolina customers, including Nucor, on a timely and current basis. With respect to witness Kollen's assertion that the effect of the Brunswick County CC deferral request only amounts to eight basis (.08%) points ROE, witness Stevens referenced the evidence in the Company's Application for Dominion North Carolina Power for an Accounting Order for the Brunswick County CC (Docket No. E-22, Sub 533), asserting that there was a 31 basis points net detrimental impact to the Company's annualized earned return under existing tariffs. This was benchmarked against the Company's fully adjusted test period North Carolina jurisdictional ROE of 5.06%, when all components for regulatory accounting purposes are properly taken into account.

With respect to Nucor witness Kollen's comparison of the Warren County CC and Brunswick County CC deferrals with a proposed deferral associated with the savings from

ODI, witness Stevens testified that the Company has reflected a full going-level of ODI savings in the base non-fuel revenue requirement in this proceeding. Witness Stevens explained that it has been this Commission's practice to approve accounting deferrals sparingly based on its well-established standard of whether a significant and unusual or extraordinary event has occurred that has materially impacted a utility's earnings and overall financial condition. The ODI program was a narrow severance program targeted at certain management layers in the organization – it would not qualify as an issue ripe for deferral given its relatively small impact. Witness Stevens stated that in the Commission's recent denial of the Public Staff's request for deferral accounting associated with a modest increase in annualized revenues resulting from the Company's January 1, 2015, extension of the agreement for electric service with Nucor (Docket No. E-22, Sub 517), the Commission noted that deferral is only warranted where an event affecting the utility's costs or revenues is unusual or extraordinary because changes in revenues, expenses, and investments happen routinely between the time a utility's rates are fixed by the Commission and the time of the next rate case and routine changes alone do not result in a change in the balance of revenues, expenses, and investments struck by the Commission's last rate Order. According to witness Stevens, the ODI program savings are not extraordinary and of such material financial significance to warrant deferral accounting consideration.

With respect to Nucor witness Kollen's proposed 10-year recovery period for the Warren County CC and Brunswick County CC deferrals, witness Stevens argued against such an extended period for the same reasons he generally disagrees with extended recovery periods for other regulatory assets in this proceeding. According to witness Stevens, North Carolina customers have also been receiving substantial fuel expense savings on a timely and current basis through the fuel factor as a direct result of the Warren County CC and Brunswick County CC investments, and it is not appropriate to substantially delay the recovery of the costs incurred that resulted in the fuel savings. Witness Stevens contended that the Commission has generally authorized a shorter time period for the amortization of deferrals associated with new major generation facilities placed into service by North Carolina electric utilities, and DNCP is not aware of the Commission using a 10-year recovery period in recent cases. Witness Stevens added that the Public Staff has agreed with the Company's proposed three-year amortization period in this case.

The Stipulation provides for deferral accounting treatment and recovery of deferred post-in-service costs for both the Warren County CC and the Brunswick County CC. The Stipulation provides that the deferred costs will be recovered over a three-year period on a levelized basis.

The issue before the Commission in this case is one of cost deferral, a recognized practice allowing recovery of unusual expenses arising from extraordinary circumstances or events; and its use, which the Commission has historically employed sparingly, does not constitute impermissible retroactive ratemaking. The Commission has established relatively clear guideposts and standards over the years for determining when a petition for deferral is appropriate. This is especially the case in the context of major new generating facilities that also create material fuel cost savings that are flowed through to ratepayers through lower fuel rates. Based upon the evidence now before the Commission, the Commission finds that DNCP has made the requisite showing that the Warren County CC and Brunswick County CC costs in question had a material impact on the Company's financial condition. As shown in the Company's Motion for Reconsideration in Docket No. E-22, Sub 519, the Company's verified Application in this case, and the testimony of Public Staff witness Fernald, the Commission also recognizes that DNCP's earnings were well below its authorized cost of equity of 10.2% when both the Warren County CC and Brunswick County CC were placed in service. Much of the evidence presented by the Company in this case, relating to its earnings at the time the Warren County CC went into service, was not presented as evidence before the Commission at the time the Commission issued its initial order of March 29, 2016, in Docket No. E-22, Sub 519, denying the Company's request for deferral of the post-in-service costs of the Warren County CC.

In consideration of the foregoing, the Commission finds and concludes that DNCP's requests to defer post-in-service costs of the Warren County CC and the Brunswick County CC should be and are hereby granted. The Commission further finds that the evidence in the record does not support Nucor witness Kollen's view that the ODI program savings are sufficiently extraordinary and of such material financial significance to warrant deferral accounting consideration. The Commission finds and concludes that for the present case deferral and recovery of the Warren County CC and Brunswick County CC deferred post-in-service costs presented in the Stipulation is just and reasonable to all parties in light of all the evidence presented.

Regulatory Assets and Liabilities with Amortization Ending in 2017

Public Staff witness Fernald identified the following regulatory assets and liabilities that will be fully amortized in 2017:

Regulatory Asset or Liability	Amortization Ends On
Unrecovered design basis costs – Surry	May 31, 2017
NUG buyout costs – Atlantic	May 31, 2017
DOE settlement	June 30, 2017
Bear Garden deferral	October 31, 2017
NUG buyout costs – Mecklenburg	October 31, 2017

Witness Fernald recommended that the unamortized balances of these regulatory assets and liabilities as of October 31, 2016 (the date the Company proposed to implement the provisional rates in this proceeding), be re-amortized over three years using a levelized amortization, consistent with her recommended treatment of the EDIT liability and deferred costs.

Company witness McLeod discussed several concerns with Public Staff witness Fernald's proposal. First, witness McLeod testified that the amortization periods for these regulatory deferrals were established by the Commission in prior cases based on the specific facts and circumstances in those cases. Second, the Public Staff's adjustment, according to witness McLeod, would result in an adjustment to rates in this case based on events scheduled beyond the close of the hearing date in this proceeding. Witness McLeod also contended that it is not appropriate to convert to a levelization approach for the treatment of regulatory assets and liabilities midstream, as this will result in either an over- or under-recovery of carrying costs on the deferral balance over the life of the asset.

The Stipulation amortizes the unamortized balances of these regulatory assets and liabilities as of October 31, 2016, based on the date the provisional rates were expected to be implemented in this proceeding, over three years using a levelized amortization, as proposed by Public Staff witness Fernald. The Commission finds and concludes that for the present case the stipulated treatment of these unamortized balances is just and reasonable to all parties in light of all the evidence presented.

Beyond Design Basis Study Regulatory Assets

Public Staff witness Fernald testified that the Company has included in other additions in this proceeding two regulatory assets related to costs incurred to perform studies at the Surry and North Anna nuclear plants as required by the Nuclear Regulatory Commission (NRC) as a result of the disaster at the Fukushima nuclear plant following an earthquake and tsunami in Japan. Witness Fernald proposed to exclude these two regulatory assets from rate base and instead include the expenses related to these NRC studies incurred in 2015 in O&M expenses in this proceeding. Witness Fernald noted that the Company did not file a request with the Commission to defer the cost of these studies. Public Staff witness Fernald commented that the Commission previously stated in prior DNCP rate case orders that it does not consider a deferral period, an amortization period, or a window for filing a deferral request to be open-ended.

In rebuttal testimony, Company witness McLeod argued that DNCP's accounting methodology for the beyond design basis study costs is consistent with the treatment of design basis documentation costs incurred in the late 1980s and early 1990s. Witness McLeod explained that at that time, the Company requested and received guidance from the FERC for design basis documentation costs incurred, and that the FERC instructed the Company to record the costs to FERC Account 182.2 (regulatory asset account), and that these costs have been included in the Company's cost of service studies in North Carolina for over two decades.

Witness McLeod testified that since these costs were mandated by the NRC, and the Company deferred them to FERC Account 182.2 in accordance with FERC's instructions, it would be improper to account for them as other O&M expenses as recommended by the Public Staff. Witness McLeod represented that the Company will make diligent efforts to seek the Commission's approval on a timelier basis in the future.

The Stipulation provides for deferral accounting treatment of the beyond design basis study costs mandated by the NRC as proposed by Company witness McLeod. The Stipulation also provides that the Company will comply with Commission Rule R8-27(a)(2) prior to establishing any regulatory assets and liabilities for North Carolina jurisdictional purposes in the future. The Commission hereby approves deferral accounting treatment for the beyond design basis study costs *nunc pro tunc* as of July 2012, which is the date the Company began deferring these costs. The Commission finds and concludes that recovery of the beyond design documentation study costs as presented in the Stipulation is just and reasonable to all parties in light of all the evidence presented.

<u>Chesapeake Decommissioning and Closure Costs Regulatory Asset</u>

In its Application, DNCP proposed to include any decommissioning and closure costs incurred at Chesapeake and to amortize such deferred costs as of June 30, 2016, across a three-year recovery period.

Nucor witness Kollen testified that the Company deferred the costs for dismantling and other site costs for Chesapeake, but did not offset those costs by the savings in O&M expense, other operating expenses, and depreciation expense. According to witness Kollen, these expenses were included in the revenue requirement in the 2012 Rate Case, and the Company will continue to collect these expenses through the revenue requirement until rates are reset at the conclusion of this proceeding, even though they no longer are incurred. Witness Kollen asserted that Nucor had requested that the Company quantify the savings since the retirement of the plant, and the Company did not do so and simply responded that the proposed regulatory asset does not include any offsets for avoided operating expenses after the facility was retired.

Witness Kollen recommended that the Commission deny the Company's request for recovery of the deferral unless DNCP can demonstrate that the costs exceed the savings until rates are reset in this proceeding. Alternatively, if the Company provides an appropriate quantification of the savings from the avoided operating expenses (realized since closure of the plant in late 2014), then the Commission should calculate the revenue requirement on the deferred cost net of the savings on a levelized basis using a 10-year amortization period.

In response to Nucor witness Kollen, Company witness Stevens noted there were no operating O&M or depreciation expenses associated with Chesapeake in the Company's 2015 test year cost of service study. The only O&M expenses are those related to closure costs incurred in the 2015 test year. Witness Stevens contended that the cost avoidance of retiring Chesapeake Units 1-4 should also be reflected in Nucor's evaluation. In the 2012 Rate Case, the Company presented information that demonstrated that to comply with the Mercury Air Toxics Standard rules it was expected that Chesapeake Units 1-4 would all require Dry Flue-Gas Desulfurization equipment by 2015. In addition, witness Stevens testified that these units would require other new environmental equipment to comply with other expected environmental rules such as CSAPR, Ozone Standard Review, NAAQS, and 316(b). Witness Stevens presented an analysis showing the net present value cost increase in lieu of retirement totaled over $190 million for these four coal units.

Witness Stevens additionally testified that the purported savings on O&M and depreciation expenses previously incurred at Chesapeake did not create a windfall for the Company that can now retroactively be captured, as Nucor witness Kollen contends. Witness Stevens contended that no further adjustments are necessary because the environmental cost avoidance well exceeded the assumed savings and certainly caused no over-recovery of DNCP’s cost of service during this period.

With respect to Nucor witness Kollen’s proposed 10-year recovery period for the Chesapeake decommissioning and closure cost deferral, witness Stevens argued against such an extended period for the same reasons he generally disagreed with extended recovery periods for regulatory assets. Witness Stevens noted that the Public Staff agreed with the Company’s proposed three-year amortization period and that this is also consistent with prior Commission treatment of regulatory assets.

The Stipulation provides for deferral accounting treatment of the Chesapeake closure costs regulatory asset and recovery over a three-year period on a levelized basis. The Commission does not findNucor’s reasoning persuasive and, therefore it declines to adopt Nucor’s recommendations in this matter. Rather, the Commission agrees with the deferral treatment as specified in the Stipulation. The Commission finds and concludes that recovery of the Chesapeake closure costs as presented in the Stipulation is just and reasonable to all parties in light of all the evidence presented and should be adopted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 24

The evidence supporting this finding of fact and these conclusions is contained in the testimony of Public Staff witness Maness and DNCP witness McLeod.

Public Staff witness Maness addressed the question of how revenues received by DNCP for CCR cost deferrals after the approved amortization period should be treated. Witness Maness testified that DNCP appears to interpret prior Commission orders to allow CCR cost deferral to continue automatically after the approved amortization period and for an indefinite period into the future. He stated that the Public Staff disagrees with DNCP's interpretation and recommends that the Commission allow deferral to continue through 2018, subject to prudency and reasonableness reviews, and subject to a credit of the approved CCR expense to future deferrals until DNCP's next general rate case.

In his rebuttal testimony, DNCP witness McLeod disagreed with the Public Staff's recommendation that the annual amortization cost should continue to be credited to DNCP’s deferred CCR costs until the Company’s next general rate case. Witness McLeod opined that the deferred CCR costs should be treated as any other cost of service expense being recovered in the Company’s non-fuel base rates.

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

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 25

The evidence supporting this finding of fact and these conclusions is contained in the testimony of Public Staff witness Fernald, the rebuttal testimony of Company witness Stevens, the Stipulation, and the entire record of this proceeding.

In her testimony, Public Staff witness Fernald made three accounting recommendations. The first recommendation related to the Yorktown Plant. Witness Fernald urged that upon the closure of the Yorktown plant, should DNCP plan to amortize Yorktown's net book value and closure costs (other than those relating to the closure of coal ash ponds, for North Carolina ratemaking purposes), that DNCP should notify the Commission of the closure and also provide the Commission with an estimate of the net book value and closure costs.

Witness Fernald's second recommendation related to the FERC USOA. She stated that under Commission Rule R8-27, the FERC USOA is prescribed for all electric utilities under the jurisdiction of the Commission. Witness Fernald noted that DNCP does not maintain its accounting system based on the FERC USOA, but instead uses a different system of accounts, which it refers to as natural accounts. Public Staff witness Fernald explained that in order to comply with the Commission's requirements and produce its financials and reports based on the FERC USOA, DNCP maintains a module to convert its natural account postings to FERC accounts.

Witness Fernald testified that the FERC USOA identifies and categorizes costs in a manner that is consistent with ratemaking and identifies costs that are of particular interest to regulators. If a company does not maintain its accounting system based on the FERC USOA, it must still be able to produce records based on the FERC USOA, to a level such that an audit trail is maintained. Witness Fernald noted that during the Public Staff's investigation, there were several instances where costs could not be audited based on the FERC USOA. Based on that, Public Staff witness Fernald recommended that the Company maintain its accounting records in a manner such that it is able to produce records based on the FERC USOA – including allocations from its affiliates such as the service company charges discussed below – so that an audit trail is maintained and fluctuations based on the FERC USOA can be explained. Witness Fernald further recommended that the Company file the procedures and processes that it will implement to improve the transparency between the FERC accounts and the natural accounts with the Commission within 90 days after issuance of the Order in this proceeding.

Witness Fernald's third recommendation related to service company charges. Each month, when DNCP is billed by its affiliated service company, Dominion Resources Services, Inc. (DRS), for (1) services performed by DRS personnel and (2) third-party bills paid by DRS and allocated to DNCP, the expenses allocated to DNCP are initially mapped to FERC Account 923 - Outside Services Employed. Witness Fernald explained that the Company has an automated program that then takes the amounts billed by DRS to DNCP each month and reclassifies items to different accounts as may be appropriate.

Witness Fernald testified that during the Public Staff's investigation, DNCP was unable to provide the specific transactions billed by DRS to DNCP by FERC account. The Company's accounting records should be maintained such that the details of the transactions billed by DRS to DNCP, including the amounts allocated for third-party bills by vendor and the FERC account to which they are charged, is available. Finally, witness Fernald recommended that the Company file the procedures and processes that it will implement to comply with this recommendation with the Commission within 90 days after the date of the Order in this proceeding.

With respect to the Public Staff's accounting recommendation regarding the Yorktown Plant, Company witness Stevens avowed that the Company would notify the Commission when the Yorktown closure occurs and provide an estimate of the undepreciated value of Yorktown at the time of closure and the estimated level of costs to be incurred for closure.

With respect to the Public Staff's second recommendation pertaining to the FERC USOA, Company witness Stevens indicated that the Public Staff applied no materiality threshold when making such statements and that the Company views its accounting practices as reasonable and appropriate.

In response to the Public Staff's generalized comment about improving transparency between FERC accounts and natural accounts, Company witness Stevens attested that the Company filed its Application for a revised Services Agreement between DRS and DNCP with the Commission on September 23, 2016. Witness Stevens reiterated the Company's commitment to provide the Public Staff with information in Docket Nos. E-22, Subs 476, 477, and 482, which will help to address the Public Staff's issues and concerns.

The Stipulation includes the following provisions addressing Public Staff witness Fernald's accounting recommendations:

(1) The Company will notify the Commission when the Yorktown Power Station closure occurs and provide estimates of its undepreciated value at the time of closure and the level of costs to be incurred for closure.

(2) The Public Staff's accounting recommendations concerning the FERC USOA and the service company charges will be addressed in Docket Nos. E-22, Subs 476, 477, and 482.

The Commission finds and concludes that the three accounting recommendations as detailed by Public Staff witness Fernald and agreed to by the Company in the Stipulation are appropriate and should be accepted. The Commission further finds and concludes that provisions set forth in the Stipulation as agreed to between the Company, the Public Staff and CIGFUR I are just and reasonable to all parties in light of all the evidence presented.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 26-28

The evidence supporting these findings of fact and conclusions is contained in the Application, the direct testimony and exhibits of Company witnesses Petrie, Haynes and Hupp, the supplemental testimony and exhibits of Company witnesses Petrie and Haynes, the testimony and exhibits of Public Staff witnesses Peedin and Lucas, the Stipulation, and the entire record in this proceeding.

In his direct testimony, witness Petrie presented an estimate of DNCP's adjusted system fuel expense for the period July 1, 2015 – June 30, 2016, of $1.689 billion, which was used by witness Haynes to estimate the anticipated reduction in the fuel factor rate. He also estimated the deferred fuel balance as of June 30, 2016, and described DNCP's forecasted fuel expense recoveries for the second half of 2016. In his supplemental testimony, witness Petrie presented an updated adjusted total system fuel expense for the 12-month period ending June 30, 2016, of $1.74 billion, as shown in the Company's August 5, 2016 fuel factor adjustment filing in Docket No. E-22, Sub 534. He noted that this total adjusted amount was calculated based on the 100% Marketer Percentage proposed by witness Hupp in his direct testimony. Witness Petrie also testified that the Company's projected fuel over-recovery at the end of December 2016, assuming an interim rate change on November 1, 2016, was approximately $3.9 million.

In his direct testimony, Company witness Haynes used a placeholder base fuel rate based on the fuel factor approved in the Company's 2015 fuel adjustment case, Docket No. E-22, Sub 526. In his supplemental testimony, witness Haynes used the updated adjusted total system fuel expense presented by witness Petrie to calculate an average base fuel factor of $0.02116/kWh, a reduction from the current base fuel factor of $0.02427/kWh. He also used the revised Rider A rate of zero consistent with the Company's 2016 fuel adjustment filing. He further testified to the Company's reintroduction of Rider A1 on November 1, 2016, for the purpose of accelerating the return of DNCP's fuel over-recovery to its customers in conjunction with placing the proposed updated non-fuel and base fuel rates into effect on a temporary basis on that date. He explained that implementation of Rider A1 will lower the estimated over-recovery balance as of December 31, 2016, and reduce further the impact of the proposed base rate increase.

In his direct testimony, Company witness Hupp presented the Company's recommendation that the Marketer Percentage applicable to DNCP be increased from 85%, as it was established in the Company's 2012 Rate Case and used in DNCP's 2015 fuel factor case, Docket No. E-22, Sub 526, to 100%. He testified that this increase would result in a more appropriate treatment of purchased power costs, because it would permit DNCP to recover all of its prudently incurred purchased power costs through fuel rates. He explained that, when DNCP purchases rather than self-generates power, it does so in order to minimize the cost incurred to meet its customers' energy requirements. As a result, the resulting cost of DNCP's market energy purchases will likely be less than the variable marginal cost of running one of the Company's own generators to meet the energy need. Witness Hupp also testified that the Company believes that any prudently incurred power purchases made to serve customers' energy requirements should be fully allowable through fuel. He stated that the variable costs of running one of the Company's generators largely represent allowable fuel costs deemed recoverable by the Commission in the Company's fuel factor cases. Therefore, witness Hupp stated, purchases of energy deemed to be less expensive than this marginal and allowable cost of fuel for fleet operations should – when shown to be prudently incurred – also be fully allowable through fuel with no impacts to base rates. He testified that this would better align the Company's recoverable fuel-related expenses with its actual costs.

Witness Hupp noted that the Company's request for relief of the PJM Order conditions, addressed below with regard to Finding of Fact No. 50, removes the barrier that the Commission identified in its order in DNCP's 2014 fuel clause adjustment proceeding as preventing the Commission from using the discretion provided at subsection (f) to permit DNCP to recover 100% of its purchased power costs through fuel, including deemed congestion related costs.

Public Staff witness Peedin testified that with respect to purchased power, DNCP is entitled under G.S. 62-133.2(a3) to recover only "the fuel cost component, as may be modified by the Commission, of electric power purchases identified in subdivision (4) of subsection (a1)," and the fuel cost component of other purchased power, through the prospective fuel factor and the EMF. She testified that the Public Staff interprets the phrase "fuel cost component, as modified by the Commission" to mean that, in DNCP's case, the fuel cost component of purchases subject to economic dispatch must be determined by the Commission when the actual cost is not known, and that the Commission may modify the method for making that determination as appropriate. She stated that allowing DNCP to recover all of the energy costs of purchased power through a Marketer Percentage of 100% appears to read this phrase out of the statute and implies that the energy costs consist solely of fuel costs. She opined that is not the case, stating that a significant portion of energy costs consist of non-fuel variable operation and maintenance expenses.

Witness Peedin recommended that the Commission adopt a Marketer Percentage of 78% to be used as a proxy for the fuel cost component of purchases for which the actual fuel cost is unknown. She stated that both methods used by the Public Staff to determine this Marketer Percentage were proposed by DNCP in its 2008 fuel proceeding, Docket No. E-22, Sub 451, as an alternative to the off-system sales method then used by DEC and DEP. Witness Peedin described the first methodology as a review of data from the 2014 and 2015 PJM State of the Market reports, which identified each fuel component of the cost of energy used to set the energy market price. She stated that according to these reports, the fuel components of energy cost for years 2014 and 2015 were both 73.90%. She described the second methodology as a review of data provided by DNCP that blended the Company's internal data with PJM State of the Market report data for the DOM Zone. She stated that the average of the 2014 and 2015 values under the two methods was 78%. Based on her recommended Marketer Percentage of 78%, witness Peedin further recommended an adjustment to DNCP's non-fuel purchased power energy expense so that 22% of that expense would flow through base rates as purchased energy costs. This resulted in an adjustment to increase the base non-fuel rates by $2.261 million and decrease fuel rates by the same amount.

The Stipulation provides for a base fuel factor of $ 0.02073/kWh, as differentiated between customer classes, as shown on Company Rebuttal Exhibit PBH-1, Schedule 9. The Stipulation also provides that the appropriate EMF to be included in DNCP's updated annual fuel factor for the 2017 rate year shall be determined by Commission order in the Company's 2016 fuel case, Docket No. E-22, Sub 534.

The Stipulation also provides for a Marketer Percentage of 78%, to remain in place until the Company's next base rate application or its 2018 fuel factor application, whichever occurs first.

No party opposed the stipulated base fuel factor or the stipulated Marketer Percentage or conducted cross-examination on these issues at the hearing.

Based on all of the evidence in this proceeding, the Commission finds and concludes that the stipulated base fuel factor of $0.02073/kWh is just and reasonable for DNCP in this case. The Commission also concludes that a marketer percentage of 78%, to be applied to appropriately determine the fuel cost component of energy purchased for which the fuel cost is unknown, should continue to be used until the Company's next base rate application or the Company's 2018 application to adjust its annual fuel factor, whichever occurs first.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 29

The evidence supporting this finding of fact and these conclusions is contained in the Application, the direct, supplemental, and rebuttal testimony and exhibits of Company witness Chapman, the direct and settlement testimony and exhibits of Public Staff witness Hinton, the direct testimony and exhibits of Nucor witness Woolridge and CUCA witness O'Donnell, the Stipulation and the hearing testimony of witness Chapman.

In the Application, and as explained by DNCP witness Chapman in his direct testimony, the Company proposed a capital structure reflecting long-term debt of 46.641% and common equity of 53.359%. Witness Chapman, who is Senior Vice President – Mergers and Acquisitions and Treasurer for the Company, testified that the appropriate capital structure for use in this case was the Company's actual capital structure as of December 31, 2015. He discussed the Company's significant capital needs going forward, and explained how the Company plans to finance those capital needs, based on a balance of debt and common equity that DNCP believes will support the Company's credit ratings going forward, and continue to enable the Company to access a number of markets, under a wide range of economic environments, on reasonable terms and conditions. He stated that this market access is critical to fund the ongoing infrastructure capital expenditure program that will be necessary to meet the Company's public service obligations in North Carolina and throughout its system. In his supplemental testimony, witness Chapman updated the Company's proposed capital structure to its actual structure as of June 30, 2016, which reflected a long-term debt component of 46.080% and an equity component of 53.920%. Based on the Company's proposed cost rates for long-term debt and common equity, witness Chapman's proposed capital structure produced an overall weighted-average cost of capital of 7.803%.

Public Staff witness Hinton initially filed testimony stating that the Company's proposed common equity ratio produces an overall return on rate base greater than necessary to maintain credit quality and continue to attract capital. Witness Hinton noted that DRI's announced acquisition of Questar Corporation (Questar) led to an S&P credit downgrade for DRI and its subsidiaries, including VEPCO, from A- to BBB+. He noted that the credit rating reports indicate that VEPCO's regulated operations have lower business risk than DRI's unregulated businesses. He opined that the Questar acquisition may contribute to an already high debt ratio for DRI. He also noted that it is too early to tell whether recent actions, in particular the Questar acquisition, pose a risk that will increase the cost of capital.

Witness Hinton referred to DRI's confidential target capital structure for the Company as support for his position on capital structure. In addition, he noted that although the Company's average equity ratio from November 2009 to March 2016 was 54.01%, in contrast the common equity ratio averaged 49.97% for the six-year period prior to November 2009. He referenced testimony submitted in a Virginia State Corporation Commission proceeding regarding the Company operating with an equity ratio at the upper end of its target range, and opined that the increase in the equity ratio in recent years is not necessary for reasonable financing or justified in terms of its impact on Company customers. He also stated that DRI has a much higher debt ratio and lower equity ratio than the Company, and asserted that the Company's ratepayers were being asked to pay a high equity ratio to help offset DRI's high debt ratio. Finally, he stated his concern about the effect of added earnings from Virginia's return on equity incentives on the Company's capital structure. Witness Hinton concluded by recommending a capital structure consisting of 50.96% common equity and 49.04% long-term debt. Witness Hinton based his recommended capital structure on data from Regulatory Research and Associates, Inc., on recently commission approved equity ratios for other vertically integrated electric utilities with comparable Standard & Poor (S&P) bond ratings between BBB+ and A-. He accepted the Company's proposed long-term debt cost rate of 4.645%.

Nucor witness Woolridge testified that DNCP's proposed capital structure includes more equity and less debt than other electric utilities, does not include short-term debt, which amounts to almost 10% of its capitalization as of December 31, 2015, and includes much less equity than the capitalization of DNCP's parent DRI. He testified that the median common equity ratios of his and witness Hevert's proxy groups are 47.1% and 48.2%, respectively, and that DNCP's proposed capitalization includes more equity and less financial risk than these averages. Witness Woolridge, like Public Staff witness Hinton, noted concerns with the use of double leverage where the regulated utility subsidiary finances equity with the use of debt raised through the parent company. Witness Woolridge also compared DNCP's capitalization as of December 31, 2015, comprised of 9.81% short term debt, 41.20% long term debt, and 48.99% common equity, to that of DRI, comprised of 13.03% short term debt, 56.61% long-term debt, and 30.36% common equity. He noted that he used utility holding companies in his proxy group because their common stock is traded in the markets, and their financial risk and equity ratios are thus relevant for comparison rather than those of operating utilities. He testified that a high equity ratio will have a downward impact on a utility's financial risk, and that the ROE should be adjusted to account for that. He stated that based on these factors he proposed a capital structure consisting of 50% long-term debt and 50% common equity. He asserted that this capital structure is more in line with the average common equity ratios approved by state regulatory commissions in electric utility rate cases in 2015 and 2016 than the Company's proposed structure. Witness Woodridge adopted the Company's proposed long-term debt cost rate of 4.65%.

CUCA witness O'Donnell testified that DNCP's proposed capital structure is not comparable to the average common equity ratio of companies in witness Hevert's comparable group nor similar to the average equity ratio granted by state regulators for electric utilities in 2015 and to-date in 2016. He stated that the average common equity ratio for witness Hevert's comparable group is 50.1%. He stated further that the average common equity ratio granted to electric utilities by regulators across the United States in 2015 was 48.86% and to-date in 2016 is 43.67%. He noted that, in 2016, excluding limited issue rider cases, there have been only five rate case decisions and two of those were made in states that use non-investor sources of capital in the regulatory capital structures. Witness O'Donnell's calculation of the common equity ratio for those two companies was 49.47%. He noted further that DRI's common equity ratio as of December 31, 2015 was 34.9%. He concluded that DNCP's requested capital structure is not representative of capital structures of utility holding companies or of operating companies. He recommended a capital structure consisting of 50% common equity and 50% long-term debt, with a weighted debt cost rate of 4.89%. He justified this recommendation as being well above the DRI equity ratio, approximately equal to the equity ratio of witness Hevert's comparable group, and slightly above the average equity ratio granted to electric utilities by state regulators across the country in 2016.

In his rebuttal testimony, witness Chapman testified that the capital structures recommended by witness Hinton (50.96% common equity, 49.04% long-term debt), Witness Woolridge and witness O'Donnell (both 50% common equity, 50% long-term debt) were not reasonable, as they ignored the Company's actual capital structure as of June 30, 2016, as well as DNCP's actual capital structure at year-end of the each of the previous three years. He stated that the actual capital structure is the relevant structure for this case because it is the structure that supports DNCP's target credit ratings, which in turn allows DNCP to attract debt investment at an attractive cost basis. He noted that the equity component of DNCP's actual capital structure as of June 30, 2016 is in line with the equity component of the Company's year-end capital structure for the previous three years as well as to the forecasted capital structure as of December 31, 2016. He disagreed with these witnesses' reliance, without further justification, on proxy groups for their capital structure recommendations, due to the difficulty of determining a truly comparable capital structure within a proxy group of peer utilities that operate in different regulatory jurisdictions.

With regard to these witnesses' comparison of the Company's proposed capital structure to that of DRI, witness Chapman stated that development of the Company's financing plan is done with the objective of maintaining the current credit ratings of the Company, not those of DRI. He stated that a similar but separate analysis is undertaken at the DRI level, which accounts for financing needs of other, non-VEPCO subsidiaries in addition to the Company. He testified that claims that the DRI capital structure is relevant for purposes of this case are unfounded, and that VEPCO ratepayers are not being singled out and asked to pay more to offset DRI's higher debt ratio. He explained that all of DRI's subsidiaries support the parent company's debt capital structure.

Witness Chapman also addressed the impact of DRI's acquisition of Questar on VEPCO's cost of capital, stating that S&P's downgrade of the entire Dominion family due to the acquisition announcement had no discernible impact on VEPCO's cost of debt. He also stated that this one "consolidated" or "family" credit rating change should not adversely impact VEPCO's cost of debt, noting the unchanged "indicator" rating for VEPCO that S&P published along with its downgraded consolidated rating. Finally, in response to arguments concerning the increase in DNCP's common equity ratio in recent years, he stated that the higher equity component that the Company has experienced since 2009 supports using the capital structure that the Company proposed in this proceeding. He stated that the actual equity ratio is appropriate as it offsets the construction risk that an equity investor would experience during a period of heavy capital spending such as the one the Company is currently undertaking. Finally, he explained that witness Hinton's concern regarding Virginia's return on equity incentives is overstated, because it has a negligible impact on DNCP's retained earnings account, and because witness Hinton did not recognize other recent events that had a significant downward impact on the Company's retained earnings.

Following settlement negotiations between DNCP, the Public Staff, and CIGFUR I, as reflected in Section II.B of the Stipulation, the Stipulating Parties proposed a capital structure of 51.75% common equity and 48.25% long-term debt. The Stipulating Parties agreed to use 4.650% for the cost of long-term debt, based on a correction that was presented in witness Chapman's rebuttal testimony and that was not challenged by any party.

In his stipulation testimony, witness Hinton testified that the capital structure reflected in the Stipulation represents a compromise by both parties in an effort to reach agreement. He accepted the change in the long-term debt cost rate from the originally proposed debt cost rate. He noted that the stipulated 51.75% equity ratio is 217 basis points lower than the Company's request, 125 basis points lower than currently authorized for DEC and DEP, 79 basis points higher than his earlier recommendation, and 75 basis points higher than the Commission-authorized equity ratio in the last two DNCP rate cases. He stated that he believes the end result of the settlement is fair and reasonable with respect to both ratepayers and shareholders, and that customers will benefit from lower rates as a result of a negotiated settlement that, if approved, will reduce the Company's proposed rate increase by over $12 million. He also noted the $400,000 to be paid by DNCP shareholders to assist low-income customers.

At the hearing in this case, witness Chapman noted as part of his summary of his testimony that, while the equity component of the stipulated capital structure is below that reflected in the Company's actual capital structure as of June 30, 2016, his opinion is that the stipulated capital structure and overall weighted average return will still allow the Company to access capital markets on reasonable terms in order to secure the capital required to make the significant investments DNCP is planning and will, therefore, benefit the Company's North Carolina customers. No party cross-examined witness Chapman at the hearing.

In its post-hearing Brief, CUCA contends that the Commission should adopt witness O'Donnell's recommendation of a 50% equity and 50% debt capital structure. Similarly, the Attorney General's Office (AGO) states that the evidence supports a capital structure that uses an equity ratio of 50% or less. To support its argument, the AGO largely relies on the testimony of witness Woolridge concerning the median equity ratio of his proxy risk group, the median equity of witness Hevert's proxy group, and the lower equity ratio of DNCP's parent company, DRI, including short-term debt. Nucor's post-hearing Brief, likewise, proposes a capital structure consisting of 50% common equity and 50% long-term debt, relying on the testimonies of witnesses Hinton, Woolridge, and O'Donnell concerning the average equity ratios of various proxy groups and the average of equity ratios approved in electric rate cases by state commissions over various periods of time. The Commission concludes that such comparisons may be relevant and of some interest, but are entitled to minimal weight in determining the appropriate capital structure for DNCP for ratemaking purposes. Instead, the Commission gives substantial weight to the rebuttal testimony of DNCP witness Chapman. He testified that it is difficult to determine a truly comparable capital structure for a proxy group of utilities that operate in different regulatory jurisdictions because not all regulatory jurisdictions define capital structure in the same manner. Some jurisdictions include and/or exclude different balance sheet items, such as short-term debt, income tax items, customer deposits, etc. For example, he contended that the average equity ratio of witness Hinton's peer group is 51.89% when calculated in a manner consistent with DNCP's proposed capital structure in this case. In addition, as noted above, witness Woolridge's proxy group used utility holding companies while DNCP is a subsidiary operating company. Finally, also important is that the mean, median, and range of equity ratios vary for different proxy groups and, therefore, the witnesses use their own discretion in arriving at their recommended capital structures after considering such comparisons.

With regard to comparisons to DRI's capital structure, witness Chapman testified that DNCPs financing plan is developed with the objective of maintaining the current credit ratings of DNCP, not those of DRI. He stated that a similar but separate analysis is undertaken at the DRI level, which accounts for financing needs of DRI's other subsidiaries, in addition to DNCP. Witness Chapman stated that all of DRI's subsidiaries support the parent company's debt capital structure.

The Commission must consider all of the evidence and exercise its independent judgment in determining the appropriate capital structure for DNCP in the context of setting DNCP's rates. The Commission gives substantial weight to Company witness Chapman's testimony regarding the Company's effort to find the appropriate balance between equity and debt financing. As witness Chapman noted, witness Woolridge and witness O'Donnell rely primarily on the averages of their respective proxy groups without providing any further rationale in support of their recommended capitalization ratios.

The Commission is also persuaded by the fact, as noted in the stipulation testimony of Public Staff witness Hinton, that the stipulated 51.75% equity ratio is 217 basis points lower than the Company's request, 125 basis points lower than currently authorized for DEC and DEP, 79 basis points higher than his earlier recommendation, and 75 basis points higher than the Commission-authorized equity ratio in the last two DNCP rate cases. The Commission places substantial weight as well on witness Hinton's conclusion that the end result of the settlement is fair and reasonable with respect to both ratepayers and shareholders, and that customers will benefit from lower rates as a result of a negotiated settlement that, if approved, will reduce the Company's proposed rate increase by over $12 million.

The Commission accords substantial weight to the stipulation testimony of witness Hinton, and finds that an equity ratio of 51.75% represents an appropriate reduction from the Company's actual ratio, for purposes of reducing the amount of higher cost equity financing to be borne by ratepayers in this case. Based upon the evidence described above and the record in this docket as a whole, the Commission finds and concludes that the stipulated capital structure and costs of long-term are fair and reasonable, and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 30-34

The evidence supporting these findings of fact and conclusions is contained in the Application, the direct, rebuttal, and stipulation testimony and exhibits of Company witnesses Curtis and Hevert, the pre-filed direct and settlement testimony and exhibits of Public Staff witness Hinton, the pre-filed direct testimony and exhibits of Nucor witness Woolridge and CUCA witness O'Donnell, the Stipulation, and the hearing testimony.

Based upon the evidence and legal analysis set forth below, the Commission concludes, based on its own independent analysis, that the stipulated rate of return on common equity of 9.90% proposed in the Stipulation in this proceeding and the resulting stipulated overall rate of return on rate base of 7.367% are just, reasonable, and fair to the Company, its shareholders and its customers and that such rates of return are fully consistent with the requirements of North Carolina law governing the establishment of public utility rates of overall return and returns on common equity.

Summary of the Evidence on Return

DNCP's existing allowed rate of return on common equity, established by the Commission in 2012 in Docket No. E-22, Sub 479, is 10.2%.[8] Its existing approved overall rate of return on rate base is 7.80%.[9] In its Application, DNCP proposed that the allowed rate of return on common equity in this proceeding be established at 10.5%. This proposed rate of return on common equity, in conjunction with the other elements of the Company's proposed capital structure, resulted in a proposed overall rate of return on rate base for the Company of 7.88%. Based on the capital structure updated to June 30, 2016, the 10.5% ROE recommended by witness Hevert, and a cost of long-term debt revised to 4.650% in witness Chapman's rebuttal testimony, the Company's final proposal for the overall rate of return was 7.805% prior to the Stipulation.

DNCP's original rate of return request was supported by the direct testimony and exhibits of DNCP witnesses Curtis and Hevert. Witness Curtis, who is Vice President – Technical Solutions for Virginia Electric and Power Company, testified to the significant capital investment needs facing the Company. He stated that in order to attract the capital needed to meet these substantial future capital needs, the Company must achieve an adequate authorized ROE in this proceeding, and that the 10.5% ROE proposed by DNCP will allow the Company to attract capital on reasonable terms in the still-volatile and highly competitive capital markets. He explained that the ability to attract capital on favorable terms is important to DNCP's ability to maintain its current credit ratings and, ultimately, minimize the cost of capital for customers. An adequate return also ensures DNCP's ability to commit capital to future construction projects to provide safe, reliable, and cost-effective electric service to North Carolina customers without eroding the Company's shareholders' interests. In witness Curtis' supplemental testimony, he stated that as of June 30, 2016, the

[8] See 2012 Rate Order; 2015 Remand Order.

[9] Id.

Company's fully-adjusted earned rate of return on equity capital for the update period was only 5.50%, far below the Company's currently-authorized 10.2%.

Witness Hevert served as DNCP's primary cost of equity witness. Witness Hevert filed direct testimony and nine exhibits in support of DNCP's request for a 10.5% return on equity. He explained that the cost of equity is the return that investors require to make an equity investment in a company, that it should reflect the return that investors require in light of the subject company's risks and the returns available on comparable investments, and that it differs from the cost of debt because it is neither directly observable nor a contractual obligation.

Witness Hevert's direct testimony and exhibits document the specific analyses he conducted in support of DNCP's rate filing and provide a detailed description of the results of his analyses and resulting cost of equity recommendations. He applied the Constant Growth and Multi-Stage forms of the DCF model, the CAPM, and the Bond Yield Plus Risk Premium approach to develop his ROE recommendation.

Witness Hevert testified that a return that is adequate to attract capital on reasonable terms enables the utility to provide service while maintaining its financial integrity, and that the utility's return should be commensurate with the returns expected elsewhere in the market for investments of equivalent risk. He stated that the Commission's decision should result in providing DNCP with the opportunity to earn an ROE that is: (1) adequate to attract capital at reasonable terms; (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on investments in enterprises having corresponding risks. He discussed the need to select a group of proxy companies to determine the cost of equity, and how he selected the proxy group for this case.

According to witness Hevert, the results of his Constant Growth DCF analysis produced a range of 8.33% to 10.01% ROE, the results of his Multi-Stage DCF analysis were a range of 9.40% to 10.09%, and the results of his Multi-Stage DCF analysis that used the current proxy group P/E ratio to calculate the terminal value was a range of 9.34% to 10.91%. The results of witness Hevert's CAPM analysis showed a range of 8.69% to 11.64%. The results of his Bond Yield Risk Premium analysis indicated an ROE range from 10.04% to 10.47%. In his rebuttal testimony, witness Hevert updated his results to show an ROE range of 8.14% to 9.32% for his Constant Growth DCF analysis, a range of 8.85% to 9.97% for his Multi-Stage DCF analysis, a range of 8.87% to 11.22% for his CAPM analysis, and a range of 10.02% to 10.38% for his Bond Yield Risk Premium analysis. Based on his analyses, witness Hevert concluded that a rate of return on common equity in the range of 10.25% to 10.75% represents the range of equity investors' required ROE for investment in integrated electric utilities in today's capital markets. Within that range, he recommended an ROE for DNCP of 10.5% in both his direct and rebuttal testimony.

Witness Hevert explained that his ROE recommendation also took into consideration several additional factors, including (1) DNCP's planned investment program, (2) the risks associated with environmental regulations, (3) the regulatory environment in which DNCP operates, (4) flotation costs, and (5) the increased uncertainty in the capital markets. With regard to the regulatory environment, he noted that North Carolina is generally considered to be a constructive regulatory jurisdiction, and that authorized ROEs tend to be correlated with the degree of regulatory supportiveness (utilities in jurisdictions considered to be more supportive tend to be authorized somewhat higher returns). He did not, however, make any specific adjustment to his ROE estimates for the effect of these factors.

Witness Hevert also considered the economic conditions in North Carolina in arriving at his ROE recommendation. He noted that the rate of unemployment has fallen substantially in North Carolina and the U.S. generally since late 2009 and early 2010, with December 2015 rates of 5.60% in the State. He noted that since the Company's last general rate filing in March 2012, unemployment in the counties served by DNCP has fallen by over 4 percentage points. He explained further that while at its peak in 2009 into early 2010, the unemployment rate in those counties reached 13.41% (1.41 percentage points higher than the statewide average), by December 2015 it had fallen to approximately 7.30% (1.80 percentage points higher than the statewide average). He summarized that although it remains higher than the national and State averages, it has fallen considerably since its peak in early 2010. Witness Hevert also noted that since 2013, the State has consistently exceeded the national rate for real gross domestic product growth, and that since 2009, median household income in North Carolina has grown at a somewhat faster annual rate than the national median income. In addition, total personal income, disposable income, personal consumption, and wages and salaries were generally on an increasing trend. Finally, he noted that since 2005, residential electricity costs in North Carolina remain approximately 13% below the national average. Based on all of these factors, witness Hevert opined that North Carolina and the counties contained within DNCP's service area continue to steadily emerge from the economic downturn that prevailed during the Company's previous rate case, and have experienced significant economic improvement during the last several years that is projected to continue. In his opinion, DNCP's proposed ROE is fair and reasonable to DNCP, its shareholders and its customers, in light of the impact of changing economic conditions on DNCP's customers.

Witness Hevert also addressed the capital market environment, and testified that the current market is one in which it is important to consider a broad range of data and models when determining the cost of equity.

Witness Chapman stated that granting the Company an authorized return of 10.5% on common equity will allow DNCP to compete in the capital markets and to raise equity and debt at reasonable rates. He testified that authorizing the Company's requested return on common equity will allow DNCP to carry out its responsibility to provide reliable services at affordable cost and is fundamental to the Company's ability to maintain a strong credit profile, and that the ability to access capital markets on reasonable terms will reduce DNCP's borrowing cost for the benefit of the customers.

Public Staff witness Hinton testified that current economic conditions are characterized by continued low inflation rates and the reduction in long-term interest rates, particularly the decrease in treasury yields since December 2012 (the time of the DNCP's last general rate case). He further opined that continued low inflation rates have led to lower expected returns in the equity markets, which he supported by recent articles denoting that investors should expect lower rates of return. Witness Hinton used the DCF model, the Regression Analysis of Allowed Returns on Equity for electric utilities, and the Comparable Earnings method as his primary methods for determining the appropriate cost of common equity. He also used the CAPM as a check on those primary methods. For his DCF and comparable earnings analyses, witness Hinton estimated DNCP's cost of equity capital by reference to a group of proxy companies. The results of his analyses were a range of 8.30% to 9.30% for the DCF method, a single estimate of 9.49% for the Regression Analysis, and a range of 9.00% to 9.80% for the Comparable Earnings method. Corrections submitted in his settlement testimony changed his DCF range to 8.40% to 9.40%, and his Comparable Earnings range to 9.03% to 9.87%, but did not change his recommended ROE for DNCP. The result of his CAPM analysis was an estimated ROE of 8.00%, which witness Hinton used as a secondary check on his other results. Witness Hinton also performed tests for the reasonableness of his recommendation: (1) his recommended capital structure and cost rates for debt and equity yielded a pre-tax interest coverage ratio of 4.3 times, and (2) for other electric utilities he identified the average approved rate of return on equity as 9.52% in the first six months of 2016 and 9.60% for all of 2015, excluding Virginia cases that added incentive points to the cost of capital in certain cases. He concluded that a reasonable range of DNCP's cost of equity is between 8.80% and 9.80%, and recommended an ROE for this case of 9.30%. Witness Hinton also recommended an overall cost of capital of 7.02%.

Witness Hinton also testified with regard to changing economic conditions noting that North Carolina Department of Commerce and Bureau of Economic Analysis data show relatively faster growth in per capita income for DNCP's service area compared to the State as a whole, for the 2000 through 2015 period. He noted that the unemployment rate for counties in the Company's service area has fallen from 10.4% in April 2013 to 6.7% as of April 2016. He concluded that while this part of the State has a relatively poor economy, these data indicate that economic conditions facing DNCP ratepayers as a whole have been improving since DNCP's last rate case.

Witness Hinton also critiqued witness Hevert's exclusive use of earnings per share forecasts to estimate the growth component of the DCF. He questioned as unrealistic the use of a 13.65% expected investment return on the S&P 500 in witness Hevert's CAPM analysis. He also questioned witness Hevert's argument that the Company's business risks deserve special consideration. Witness Hinton testified against any risk adjustment due to the Company's projected level of capital expenditures, its level of coal generation, and compliance with the Clean Power Plan, which he believed were risks already factored into return requirements by investors and did not deserve any special recognition or consideration.

Nucor witness Woolridge recommended an ROE of 8.60%, which is near the upper end of the range based on his DCF and CAPM analyses. He applied the constant growth version of the DCF method and the CAPM methods to a proxy group of publicly held electric utilities. He relied primarily on his DCF analysis, as he believes it provides the best measure of public utility equity cost rates. Witness Woolridge concluded that the appropriate equity cost rate for companies in his and witness Hevert's proxy groups is in the 7.90% to 8.75% range. He acknowledged that his recommendation is below the average authorized ROEs for electric utility companies.

Witness Woolridge also offered a critique of witness Hevert's ROE recommendation. He asserted with regard to capital market conditions that the forecasts of higher interest rates that witness Hevert used his CAPM and Risk premium analysis are incorrect. He questioned the inputs to witness Hevert's DCF analysis, in particular, his exclusive use of earnings per share forecasts; he disagreed with the low weight that witness Hevert gave his constant-growth DCF results; and he disagreed with witness Hevert's claim that high price-earnings (P/E) ratios can lead to low DCF results. He stated that the projected interest rates and market or equity risk premiums in witness Hevert's CAPM and risk premium approaches are excessive and not reflective of current and prospective market fundamentals. Finally, he disagreed with witness Hevert's inclusion of a flotation cost adjustment to the ROE.

CUCA witness O'Donnell did not conduct his own DCF or other method of determining the appropriate ROE in this case, citing the late entry to the case by CUCA. Rather, he revised the values included in witness Hevert's analyses to correct errors he perceived in those analyses, and, based on those adjustments, recommended an ROE of 9.0% out of a range of 8.50% to 9.50% and, together with his recommended capital structure discussed above, an overall cost of capital of 6.94%. Witness O'Donnell disagreed with the long-term growth rate witness Hevert used for his multi-stage DCF analysis, and with witness Hevert's testimony that, when constant growth DCF results are below the past returns authorized by regulators the validity of the constant growth DCF model is questionable. Witness O'Donnell also disagreed with witness Hevert's explanation of why it is reasonable to focus on different methodologies given the differences in financial markets over time. Witness O'Donnell opined that the expected market return that witness Hevert used for his CAPM and risk premium analyses is not reasonable, and asserted that the Company's requested ROE in this case is related to, but inconsistent with, its pension expense request. He also referenced a September 2, 2015 Order by the Missouri Public Service Commission where that commission found that witness Hevert's CAPM and Risk Premium model resulted in inflated results and his constant growth and multi-stage DCF models are based on excessively high growth rates. Witness O'Donnell presented a graph of allowed ROEs by state regulators across the country over the past 15 years and he noted that in 2016 no electric utility has been granted an ROE in excess of 10%.

In his rebuttal testimony, witness Hevert addressed witness Hinton's analyses with respect primarily to the issues of composition and selection of the proxy group, the growth rates and dividend yields applied in the constant growth DCF model, the application of the Regression Model of Allowed Returns, the reasonableness of the Comparable Earnings method, the application of the CAPM, the relevance of flotation costs in determining the Company's cost of equity, and the business risk of DNCP relative to the proxy group.

Witness Hevert also addressed witness Woolridge's testimony, and explained why the results of witness Woolridge's analyses are not reasonable estimates of the Company's cost of equity. Witness Hevert explained how several aspects of witness Woolridge's DCF analyses and conclusions are not compatible with market conditions and are inconsistent with the practical interpretation of the models' results. Witness Hevert also showed that the growth rates that witness Woolridge asserts are overstated by historical standards represent approximately the 50th to 51st percentile of the actual capital appreciation rates observed from 1926 to 2015. He noted that from January 2014 through September 16, 2016, no utility commission had authorized a return as low as 8.60%, which is Witness Woolridge's recommendation in this case. He also noted Witness Woolridge's recognition that his recommendation is below the average for authorized ROEs for electric utilities, and that the lowest authorized ROE for a vertically integrated electric utility since January 2014 was 70 basis points above witness Woolridge's 8.60%. Witness Hevert also disagreed with witness Woolridge's assertions regarding market/book ratios and the cost of equity and provided updated data in support of that position. Finally, he testified in response to witness Woolridge's proxy group selection and expanded on his position regarding flotation costs.

In his rebuttal to witness O'Donnell's testimony, witness Hevert reiterated that all models are subject to limiting assumptions that may not be valid under certain market conditions, and that it is important to consider the results of multiple methods when estimating the cost of equity. He stated that this position is consistent with the Hope and Bluefield findings that it is the analytical result, as opposed to the methodology, that controls in arriving at ROE determinations. He stated further that a reasonable ROE estimate appropriately considers alternative methodologies and the reasonableness of their individual and collective results in light of the specific case at hand. He explained that capital market conditions influence the application and interpretation of ROE models, because the cost of equity is not directly observable and must be estimated using analytical techniques that rely on market-based data to quantify investor expectations and requirements. Specifically with regard to the constant-growth DCF model, witness Hevert explained that he gave the results of that model less weight in this case for two reasons. First, while one of the limiting assumptions of this model is that the P/E ratio will remain constant over time, the proxy group average P/E ratio had recently been trading at an unusual level relative to the overall market's P/E ratio, and since the date of the analysis he presented in direct testimony had been quite unstable. Second, constant-growth DCF model results recently have been well below the returns authorized for other vertically integrated electric utilities. Witness Hevert also addressed each of witness O'Donnell's contentions regarding the consistency of witness Hevert's ROE analysis as compared to his past analyses, and testified that those contentions are misplaced and should be given little weight.

Witness Hevert also testified that witness O'Donnell provided no testimony as to the reasonableness of the multi-stage DCF model or its application in this proceeding other than with respect to the long-term growth rate, and testified further as to the reasonableness of that rate. Witness Hevert also addressed witness O'Donnell's contentions as to the expected market return and other aspects of his CAPM and risk premium analyses. With respect to witness O'Donnell's contentions regarding the Company's pension fund's expected returns, witness Hevert testified that pension funding expectations should not be viewed as a measure of investors' required return, as the two are developed in separate manners and are used for different purposes.

Finally, in his rebuttal witness Hevert updated his analysis of economic conditions in North Carolina and DNCP's service area and testified that it continues to be his view that on balance, economic data regarding North Carolina and the U.S. do not alter his cost of equity estimates, or his recommendations, one way or the other. He also noted the importance of keeping in mind that the models used to estimate the cost of equity reflect capital markets and, therefore, general economic conditions. He stated that, given that changes in economic conditions in North Carolina are related to the domestic economy, it is reasonable to conclude that both are reflected in ROE estimates.

As reflected in Section II.B of the Stipulation, the Stipulating Parties agreed to an ROE of 9.90%. In the same Section, the Stipulating Parties also agreed that DNCP should be allowed to earn an overall rate of return on its rate base of 7.367%.

The overall return on rate base and the proposed allowed rate of return on common equity set forth in the Stipulation were supported by the stipulation testimony of DNCP witnesses Curtis and Hevert and Public Staff witness Hinton, and the hearing testimony of witness Hevert.

Witness Curtis testified that the Stipulation, including the stipulated 9.90% ROE, successfully strikes the balance of the Company's need for rate relief with the impact of that rate relief on customers.

Witness Hevert testified that although the stipulated ROE is somewhat below the lower bound of his recommended range (10.25%), he recognizes that the Stipulation represents the give-and-take among the Stipulating Parties regarding multiple, otherwise contested issues. He stated his understanding that the Company has determined that the Stipulation terms, taken as a whole, are such that it will be able to raise the external capital required to continue the investments required to provide safe and reliable service when needed at reasonable cost rates, and he appreciates and respects that determination. While his position remains that a range of 10.25% to 10.75% would represent a reasonable and appropriate measure of DNCP's cost of equity in a fully litigated proceeding, he stated that he recognizes the benefits associated with the decision to enter into the Stipulation and as such it is his view that the 9.90% stipulated ROE is a reasonable resolution of an otherwise-contested issue. Witness Hevert also testified that North Carolina falls in the top one-third of jurisdictions in terms of being a constructive regulatory jurisdiction according to RRA, and reiterated the importance of the perception of constructive regulatory environment to ratings agencies. He stated that the stipulated ROE is a reasonable outcome based on its being within three basis points of the average return of 9.87% (and seven basis points of the median) authorized for vertically integrated electric utilities from 2013 through 2016. He also stated that of the 77 cases decided during that period, 35 included authorized returns of 9.90% or higher. He also noted that the stipulated ROE falls 21 basis points below the average (and 30 basis points below the median) authorized ROE during the 2013-2016 time period for jurisdictions that are comparable to North Carolina's constructive regulatory environment and that from that perspective, the stipulated ROE is a somewhat conservative measure of the Company's cost of equity. Finally, witness Hevert testified that on balance, the impact of changing economic conditions data discussed in his direct and rebuttal testimony do not alter his ROE estimates or recommendation, and also do not alter his support of the Company's decision to agree to the stipulated ROE.

Witness Hinton supported the Stipulation as it relates to the cost of equity capital to be used in setting rates in this case, and made several changes and corrections to his direct testimony that did not alter his pre-settlement 9.3% ROE recommendation. He observed that the stipulated 9.90% ROE is higher than his recommended range of 8.80% to 9.80%, and lower than the Company's recommended range of 10.25% to 10.75%. He testified that the 9.90% represents a reasonable middle ground between the Public Staff and DNCP rather than acceptance of a particular analytical model. He also testified that the agreements on ROE and capital structure discussed above could only occur in the context of various compromises by both parties on other issues. Finally, he testified that he believes a 9.90% ROE accounts for the impact on customers when viewed in the context of the overall settlement. He stated that, first, the settlement as a whole is reasonable with regard to the ultimate impact on customers, which is the impact on their monthly bills. Second, he noted that the impact of changing economic conditions in the DNCP service territory is difficult to adequately quantify, as there exist both economic improvement and economic problems. Third, he noted that the one-time payment of $400,000 to assist DNCP's low-income customers in North Carolina, which will come from earnings that would otherwise go to shareholders, will help mitigate the rate increase for the customers who have the greatest need and feel the impact of economic conditions most severely. Witness Hinton concluded that because the contribution could not lawfully be ordered by the Commission in the absence of Company agreement, it therefore provides a response to the impact of economic conditions on customers that could only exist with a settlement agreement, which adds to the reasonableness of the agreed-upon ROE.

At the hearing, witness Hevert testified in response to questions from counsel for CUCA and the Attorney General with regard to the 13.45% Bloomberg estimated market return he used in his CAPM analysis, which as he explained in his rebuttal testimony reflects return expected by analysts covering the companies that compose the S&P 500 Index. It does not represent the return for utilities, but is the expected market return from which the risk-free rate of return is subtracted to find the Market Risk Premium. The Market Risk Premium is then multiplied by the Beta coefficient, which represents a given utility's risk relative to the market. At the hearing, witness Hevert stated that 13.45% is well within that range considering an average historical market return of 12%, and the historical variation in returns of about 20%. In response to questioning from CUCA counsel as to whether his recommended ROE would be higher or lower if he had used the same approaches to his methodologies in this case as in previous cases, witness Hevert explained that it makes sense to apply different weights to the approaches as the markets change, because one model's assumptions no longer become as relevant to the market circumstances as they had been.

In response to questioning by the Attorney General, witness Hevert testified to the recent volatility in the utility sector, as exemplified by the variance in stock prices used as an input to his constant growth DCF analysis. In response to questions from counsel for Nucor, witness Hevert testified that looking at annual averages of returns may indicate a distorted view of trends in returns, since there may be years with fewer cases, or years with cases from jurisdictions that tend to authorize lower returns, rather than looking at individual cases.

On redirect questioning, witness Hevert reiterated that state regulatory commissions generally do not base rate of return decisions on evidence provided by a single witness, and that often state commissions like the Commission have authorized returns lower than his recommendation and higher than intervenor recommendations. He confirmed that the stipulated ROE of 9.90% is slightly below the lower end of his recommended range, and slightly above the higher end of Public Staff witness Hinton's recommended range. He stated the only instance he can recall of a commission authorizing an ROE comparable to the 9.0% and 8.6% ROEs recommended by Nucor and CUCA was in Hawaii, and that that case involved a reduction to the authorized ROE to account for system inefficiencies.

Public Witness Testimony

The public witness testimony heard by the Commission is summarized below.

Belinda Joyner of Garysburg in Northampton County, testifying on behalf of Concerned Citizens of Northampton County, stated that elderly customers on fixed income and retired State employees have to make purchasing decisions based on their limited income whether to buy groceries, medicine, and other items. She testified that without power these customers cannot cook, wash, nor otherwise function, and that a 17% increase in rates is unfair.

Tony Burnette, President of the Northampton County NAACP, is a caregiver for her elderly mother. She testified that a 17% increase would be detrimental to elderly customers and that elderly customers are often at home all day, and would likely use more than the 1000 kilowatts (kW), the monthly usage of an average customer.

Larry Abram of Tillery in Halifax County agreed with other witnesses regarding the difficulty elderly customers would have paying their bills.

Dean Knight of Halifax testified that his cotton gin business has electric bills of about $150,000 per month for three months of the year, and he must pay for improvements to his equipment within his budget, rather than by raising his rates.

Janice Bellamy of Whitakers in Edgecombe and Nash Counties testified to the difficulty she and others on fixed incomes have in paying their bills, such as water and electric bills.

Regina Moffett of Whitakers, advocating for seniors, stated that the proposed rate increase would impact the entire local community and that higher bills would result in decreased church contributions. She also testified that when she became a Dominion customer, she saw a "great decrease" in her electric bill.

Betty Bennett of Garysburg testified that a 17% increase in electricity rates was too high.

Peter Bishop, the Director of Economic Development for Currituck County, testified on behalf of the Currituck County Board of Commissioners. He testified with respect to DNCP witness Hevert's testimony that while North Carolina "and this region" have improved significantly since the recession, the counties within DNCP's service area have not fared well. He stated that the Company could have made a better argument with regard to economic conditions in the area and presented several statistics related to unemployment, poverty rate, median household income, net loss of population, and new businesses showing that the counties within DNCP's service area are worse off than other counties in the State. Mr. Bishop also recommended that the Commission exercise caution when making determinations regarding recovery of coal ash costs, as this is a developing issue, and stated that the best approach may be to wait and see how coal ash cost recovery is handled in the federal courts before setting precedent for this State.

Robert Woodard, Chairman of the Dare County Board of Commissioners, testified in support of the Dare County Board of Commissioners' resolution that was filed on July 19, 2016, in this proceeding. He also testified that the Board's position is that any rate increase would place an undue hardship on Dare County's citizens.

Walter Overman, Vice Chairman of the Dare County Board of Commissioners, testified that Dare County's population has not seen a 17% or even a 6% increase in wages since DNCP's last rate case. He testified that lower-wage residents would be hit especially hard in an area with a high cost of living. He asked that the rate increase be denied.

Dwight Wheless of Columbia in Tyrrell County testified in support of the Columbia Town Board of Aldermen's resolution in opposition to the proposed rate increase. He testified that Tyrrell County has the second lowest per capita income in the State and its citizens would be most hurt by an increase in the cost of electricity. He also testified that Columbia has not experienced any recovery and that its residents are already challenged by constant increases in the cost of food and pharmaceuticals.

Robert Edwards of Nags Head in Dare County testified that the requested rate increase should not be granted. He testified that inflation has remained near zero in recent years and that if the Company made wise and prudent investments, those alone should have improved productivity and reduced costs so that customer rates should actually be lowered. He testified that DNCP should hedge fuel cost fluctuations with long-term purchase agreements and that customers should not be exposed to fuel cost increases. He testified that the proposed increase for residential customers as compared to large users is unfair, and that the requested rate of return on equity is too high.

Manny Madeiros of Kitty Hawk in Dare County testified that DNCP's retail electric rates should not reflect the cost of renewable energy production.

Judy Williams of Manteo in Dare County testified that she and others are living on fixed incomes and even a 7% increase in rates is too high.

Martha MacDonald of Williamston in Martin County testified that the rate increase would have a direct negative impact on seniors, most of whom have Social Security as their sole income, averaging $1300 a month. She testified that Martin County is a Tier 1 County, and that seniors are often forced to choose between paying their electric or water bills or buying food or medicine. She also testified that some residents cannot afford detached homes with insulation and are paying high bills for electricity in mobile homes. She testified that DNCP does a good job restoring power when there are outages.

John MacDonald of Williamston testified that he and many customers in the area are on fixed incomes and cannot afford the proposed rate increase.

Tawilda Bryant of Jamesville in Martin County testified in support of Ms. MacDonald's testimony on the impact of the proposed rate increase on seniors.

Rhett White, the Town Manager of Columbia in Tyrrell County, testified that the Town has struggled in the past to absorb electric rate increases and fuel charge adjustments without increasing local property taxes. He testified that Columbia could not withstand an increase of even 5.9% without an increase of 2 cents per $100 in the Town's tax rate. He testified that many of Columbia's elderly residents are on fixed incomes, sometimes living on the minimum Social Security check of $750 per month. He testified that a typical widowed resident living in a home valued at $75,000 would have to pay another $15 in annual taxes to cover the Town's increased power bills, in addition to the more than $84 that she will pay for her own residential power bill. He also testified that the increase to the County's own power bills would result in increased county taxes for that same resident. He stated that the proposed rate increase would negatively affect the Town's businesses and industry, and that the recent recession is not over in rural Columbia and Tyrrell County. He testified that wages are lower than elsewhere in northeastern North Carolina, unemployment is much higher than throughout the State, poverty rates are high, median household incomes remain the lowest in the region, and out-migration of young residents in search of jobs continues. He testified that the economic climate in Columbia is very different from that described by DNCP witness Hevert, and that the Town is made up mostly of low-income, working residents in a Tier 1 County.

Ronnie Smith, the Chair of the County Commissioners of Martin County, testified that many people in the area cannot afford the proposed increase, and that even small increases impact residents on fixed incomes.

John Liddick of Williamston testified that during the cold winter weather in the past, residents have said they could not afford their electric bills.

Linda Gibson of Williamston testified that most seniors are on fixed incomes of $600 or $700 per month, and that once they pay one or two bills, they have just enough left to buy food. She testified that most jobs in Martin County pay minimum wage or just a bit more and even young people have trouble making ends meet. She also testified in support of DNCP's good service in terms of restoring power after outages.

Samantha Komar of Williamston testified that she is a veteran and on a fixed income. She testified that the median income in the town is $15,000 per year and that residents already often have to choose between paying their electric and water bills or for food and medication.

Louise Simmons of Jamesville testified that she would not be able to pay any more on her electric bill.

Jerry McCrary, the Mayor of Parmele, Martin County, testified that Parmele has about 300 citizens, the majority of whom are seniors. He also testified that the proposed rate increase would harm these residents who already have to choose between buying food, medicine, and paying their bills.

Glenda Barnes of Parmele testified that the proposed 17% increase is too high.

Reginald William Ross, Jr. of Williamston testified that many of the local residents are seniors on fixed income making difficult choices about buying food or medicine.

Legal Standards Applicable to Rate of Return Findings by the Commission

The Commission's analysis of and decision on rate of return on rate base and allowed rate of return on common equity in this case is governed by the United States Supreme Court's Hope and Bluefield decisions,[10] the requirements of G.S. 62-133, and the North Carolina Supreme Court decisions interpreting and applying each of the foregoing to rate of return decisions by the Commission.

[10] Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944) (Hope); Bluefield Waterworks & Improvement Co. v. Public Service Commission, 262 U.S. 679 (1923) (Bluefield).

In Bluefield, the US Supreme Court established the basic framework for rate of return regulation of public utilities. On this subject, the Court held that:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; . . . [t]he return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.

Bluefield, 262 U.S. at 692-93. In the subsequent Hope decision, the Court expanded on its analysis by stating:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock…. By that standard the return to the equity owner should be commensurate with the returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

Hope, 320 U.S. at 603.

The Commission has looked to the Hope and Bluefield standards as guidance for setting rates. In Docket No. E-7, Sub 1026, the Commission noted that:

> First, there are, as the Commission noted in the DEP Rate Order, constitutional constraints upon the Commission's return on equity decision, established by the United States Supreme Court decisions in *Bluefield Waterworks & Improvement Co., v. Pub. Serv. Comm'n of W. Va*., 262 U.S. 679 (1923) (*Bluefield*), and *Fed. Power Comm'n v. Hope Natural Gas Co*., 320 U.S. 591 (1944) (*Hope*): To fix rates that do not allow a utility to recover its costs, including the cost of equity capital, would be an unconstitutional taking. In assessing the impact of changing economic conditions on customers in setting an ROE, the Commission must still provide the public utility with the opportunity, by sound management, to (1) produce a fair profit for its shareholders, in view of current economic conditions, (2) maintain its facilities and service, and (3) compete in the marketplace for capital. State ex rel. Utilities Commission v. General Telephone Co. of the Southeast, 281 N.C. 318, 370, 189 S.E.2d 705, 757 (1972). As the Supreme Court held in that case, these factors constitute "the test of a fair rate of return declared" in Bluefield and Hope.

Id., at 7.

The Commission must balance the interests of investors and customers in setting the rate of return on equity. As the Commission has stated, "the Commission is and must always be mindful of the North Carolina Supreme Court's command that the Commission's task is to set rates as low as possible consistent with the dictates of the United States and North Carolina Constitutions."[11] In that regard, the return should be neither excessive nor confiscatory; it should be the minimum amount needed to meet the Hope and Bluefield comparable risk, capital attraction, and financial integrity standards.

In addition, the Supreme Court has held that "although the Commission must make findings of fact with respect to the impact of changing economic conditions upon consumers," it is not required to "'quantify' the influence of this factor upon the final ROE determination."[12] The Commission echoed this distinction in the 2015 Remand Order as well, stating that it is "not required to isolate and quantify the effect of changing economic conditions on consumers in order to determine the appropriate rate of return on equity."[13]

The Supreme Court has also, however, made clear that the Commission "must make findings of fact regarding the impact of changing economic conditions on customers when determining the proper ROE for a public utility."[14] In Cooper II, which addressed an appeal of the Commission's order on DNCP's previous base rate application, the Supreme Court directed the Commission on remand to "make additional findings of fact concerning the impact of changing economic conditions on customers."[15] The Commission made such additional findings of fact in its Order on Remand.[16]

Finally, when a settlement agreement has not been adopted by all of the parties to a case, its acceptance by the Commission is governed by the standards set out by the

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[11] Docket No. E-7, Sub 1026, Order Granting General Rate Increase, (Sept. 24, 2013) at 24; see also Docket No. G-9, Sub 631, Order Approving Partial Rate Increase and Allowing Integrity Management Rider, (Dec. 17, 2013), at 26 (noting North Carolina Supreme Court's determination that the provisions of G.S. 62-133 "effectively require the Commission to fix rates as low as may be reasonably consistent with the requirements of the Due Process Clause of the Fourteenth Amendment to the Constitution of the United States, those of the State Constitution, Art. I, § 19, being the same in this respect"); 2015 Remand Order at 40 ("the Commission in every case seeks to comply with the North Carolina Supreme Court's mandate that the Commission establish rates as low as possible within Constitutional limits.").

[12] State ex rel. Utilities Comm'n v. Cooper, 367 N.C. 644, 766 S.E.2d 827 (2014). In this case the court affirmed the Commission's Order on Remand, issued October 23, 2013, in Docket No. E-7, Sub 989, at pages 34-35, where the Commission pointed out that "adjusting investors' required costs based on factors upon which investors do not base their willingness to invest is an unsupportable theory or concept. The proper way to take into account customer ability to pay is in the Commission's exercise of fixing rates as low as reasonably possible without violating constitutional proscriptions against confiscation of property. This is in accord with the 'end result' test of Hope. This the Commission has done." See also State ex rel. Utils. Comm'n v. Cooper, 367 N.C. 741, 745-46, 767 S.E.2d 305, 308 (2015).

[13] DNCP Remand Order at 26.

[14] State ex rel. Utils. Comm'n v. Cooper, 367 N.C. 430, 758 S.E.2d 635, 642 (2014) (Cooper II), See also State ex rel. Utils. Comm'n v. Cooper, 366 N.C. 484, 739 S.E.2d 541 (2013) (Cooper I).

[15] Cooper II, 758 S.E.2d at 643.

[16] DNCP Remand Order at 4-10.

North Carolina Supreme Court in State ex rel. Utilities Commission v. Carolina Utility Customers Association, Inc., 348 N.C. 452, 500 S.E.2d 693 (1998) (CUCA I), and State ex rel. Utilities Commission v. Carolina Utility Customers Association, Inc., 351 N.C. 223, 524 S.E.2d 10 (2000) (CUCA II). In CUCA I, the Supreme Court held that

> [A] stipulation entered into by less than all of the parties as to any facts or issues in a contested case proceeding under Chapter 62 should be accorded full consideration and weighed by the Commission with all other evidence presented by any of the parties in the proceeding. The Commission must consider the nonunanimous stipulation along with all the evidence presented and any other facts the Commission finds relevant to the fair and just determination of the proceeding. The Commission may even adopt the recommendations or provisions of the nonunanimous stipulation as long as the Commission sets forth its reasoning and makes "its own independent conclusion" supported by substantial evidence on the record that the proposal is just and reasonable to all parties in light of all the evidence presented.

348 N.C. at 466, 500 S.E.2d at 703.

However, as the Court made clear in CUCA II, the fact that fewer than all of the parties have adopted a settlement did not permit the Court to subject the Commission's Order adopting the provisions of a nonunanimous stipulation to a "heightened standard" of review. 351 N.C. at 231, 524 S.E.2d at 16. Rather, the Court said that Commission approval of the provisions of a nonunanimous stipulation "requires *only* that the Commission ma[k]e an independent determination supported by substantial evidence on the record [and] ... satisf[y] the requirements of chapter 62 by independently considering and analyzing all the evidence and any other facts relevant to a determination that the proposal is just and reasonable to all parties." Id., at 231-32, 524 S.E.2d at 16. (emphasis added).

With these legal principles in mind, the Commission now turns to the analysis of the evidence in this proceeding relating to a determination of the appropriate overall rate of return on rate base and allowed return on common equity for use in this proceeding.

Analysis of the Evidence

In order to reach an appropriate independent conclusion regarding return on equity, the Commission should evaluate the available evidence, particularly that presented by conflicting expert witnesses. Cooper I, 366 N.C. at 492-493; CUCA I, 348 N.C. at 460-467; CUCA II, 351 N.C. at 229-230.

In addition to its evaluation of the expert evidence, the Commission must also make findings of fact regarding the impact of changing economic conditions on customers when determining the approved rate of return on equity for a public utility. Cooper, 366 N.C. at 491, 739 S.E.2d at 548. There is no specific and discrete numerical basis for quantifying the impact of economic conditions on customers. However, the impact on customers of changing economic conditions is embedded in the return on equity expert witnesses' analyses. The Commission noted this at page 38 of its 2012 Rate Order: "This impact is essentially inherent in the ranges presented by the return on equity expert witnesses, whose testimony plainly recognized economic conditions – through the use of econometric models – as a factor to be considered in setting rates of return."

The evidence in this proceeding related to the determination of an overall rate of return on rate base and allowed rate of return on common equity is provided in the testimony of the public witnesses, the testimony and exhibits of DNCP's witness Hevert (and, in support of witness Hevert's recommendations, in the testimony of DNCP witnesses Curtis and Chapman), and the testimony and exhibits of Public Staff witness Hinton, Nucor witness Woolridge, and CUCA witness O'Donnell, and the Stipulation.

Witness Hevert used four different analytical methods, each with multiple variations, to estimate the cost of equity capital for DNCP. He ran a constant growth DCF method with 30-day, 90-day and 180-day low, mean, and high averages for each of his proxy companies, which as updated in his rebuttal testimony resulted in a rate of return on equity range of 8.14% to 9.32%. The range for his updated multi-stage DCF analysis is 8.85% to 9.97%. The range for his updated CAPM analysis is 8.87% to 11.22%, and the range for his updated bond yield plus risk premium analysis is 10.02% to 10.38%. The range between the highest number produced by the four methodologies, 11.22%, and the lowest number, 8.14%, encompasses the stipulated rate of return on equity of 9.90%. Further, the average of witness Hevert's updated analytical results, using the DCF mean growth rate results, is 9.45% (where the CAPM is based on the Bloomberg market risk premium) to 9.58% (where the CAPM is based on the Value Line market risk premium). However, witness Hevert testified that the constant growth DCF results "are difficult to reconcile with observable, prevailing market conditions," and likely reflect increases in utility stock prices that are a temporary overvaluation.

The Commission gives significant weight to witness Hevert's testimony that constant growth DCF results should be viewed with caution in current market conditions. While current stock prices are an observable fact, whether overvalued or not, an underlying assumption of the constant growth DCF is that the price to earnings ratio (P/E) remains constant. However, as noted by witness Hervert, utility sector P/E ratios have increased to the point that they have exceeded both their long-term average and the market P/E. In addition, constant growth DCF results are below authorized returns.

As a result, the Commission finds it reasonable in the current economic circumstances to give no weight to the constant growth DCF results, and to give substantial weight to an averaging of the high growth rate multi-stage DCF, the Value Line-based market risk premium CAPM, and the bond yield plus risk premium results, which indicates a 9.86% ROE. The result of this averaging, being only four basis points below the stipulated 9.90% ROE, is strongly supportive of the stipulated ROE, particularly in light of the Supreme Court's decision in State ex rel. Utils. Comm'n v. General Telephone Co., 285 N.C. 671, 681, 208 S.E.2d 681, 670 (1974) (a "zone of reasonableness extending over a few hundredths of one percent" exists within which the Commission may appropriately exercise its discretion in choosing a proper rate of return on equity).

In addition, the Commission gives substantial weight to witness Hevert's stipulation testimony in support of the stipulated 9.90% ROE. He testified that although the stipulated ROE is somewhat below the lower bound of his recommended range (i.e., 10.25%), he recognized that the Stipulation represents the give-and-take among the Stipulating Parties regarding multiple issues that would otherwise be contested by the Stipulating Parties. In addition, he relied on DNCP's determination that the terms of the Stipulation, taken as a whole, are such that DNCP will be able to raise the capital required to continue the investments required to provide safe and reliable service, and that it will be able to do so when needed and at a reasonable cost rates. The Commission notes that the approved ROE is just one of many factors that affect the earnings available to pay a return to equity investors, and therefore it is essential to assess the reasonableness of the ROE in the context of all the issues that affect earnings.

The Commission agrees with witness Hevert's testimony that although the stipulated ROE falls within the range of analytical results presented in his direct and rebuttal testimony, current capital market conditions are such that the models used to estimate the cost of equity continue to produce a wide range of sometimes conflicting estimates. Indeed, all the cost of capital witnesses used multiple analytical models, with wide-ranging results.

The Commission also gives substantial weight to witness Hevert's testimony that it is important to keep in mind that the models used to estimate the cost of equity reflect capital markets and, therefore, general economic conditions. Given that changes in economic conditions in North Carolina are related to the domestic economy, it is reasonable to conclude that both are reflected in the analytical estimates of the ROE. The Commission further finds credible witness Hevert's testimony that, on balance, economic data regarding North Carolina and the United States do not alter the cost of equity estimates one way or the other.

The Commission additionally gives substantial weight to the stipulation testimony of Company witness Curtis that the concessions the Company has made through the Stipulation reasonably balance its customers' interest in receiving the lowest rate impact while also meeting DNCP's need to recover the substantial investments that it has made in order to continue to comply with regulatory requirements and safely provide high quality electric service.

Based on the testimony of DNCP witnesses Hevert and Curtis, the 9.90% stipulated ROE, in the context of the settlement as a whole, will be sufficient to meet the requirements of investors in capital markets. The corresponding question is whether a 9.90% ROE imposes no more burden on DNCP customers than is necessary for the Company to provide reliable electric service. In this regard, the Commission gives substantial weight to Public Staff witness Hinton's settlement testimony that the stipulated

9.90% ROE represents a reasonable middle ground between the Public Staff and DNCP, higher than his recommended range of 8.80% to 9.80%, and lower than the Company's recommended range of 10.25% to 10.75%.

The Commission also gives weight to witness Hinton's direct and settlement testimony in its focus on the impact on customers from multiple perspectives. In particular, he testified regarding: (1) data showing improvement in economic conditions, notably unemployment and per capita income, for the population within DNCP's service territory; (2) the benefit customers will receive from lower rates as a result of a negotiated settlement that will reduce the Company's proposed rate increase by over $12 million – a result that eliminates uncertainty regarding the chance that a higher rate increase could have been approved in a fully-contested proceeding; and (3) the $400,000 to be paid by shareholders to assist low-income customers who are the most impacted by a rate increase.

Witness Hinton's direct (pre-settlement) testimony employed three primary analytical methods: a constant growth DCF, a regression analysis of allowed ROEs, and the comparable earnings method. The Commission finds the high end of his comparable earnings results to be probative and compelling in the circumstances of this case. As witness Hinton noted, the comparable earnings method is well-suited to the Hope legal standard of authorizing a utility ROE that allows investors to earn a return comparable to returns available on alternative investments with similar risk. As a result, the Commission gives substantial weight to the high end of the range of results from witness Hinton's updated comparable earnings analysis, where the three highest ROE results – 10.0%, 9.9% and 9.7% - average 9.867%. The Commission considers such substantial weight appropriate in the present circumstances where there is a wide range of analytical results, all with strengths and weaknesses. Thus, it is reasonable to rely more heavily on results that support a middle ground among the analyses of the competing witnesses.

Nucor witness Woolridge acknowledged that his recommendation of an ROE of 8.60% out of a range of 7.90% to 8.75% is below the average authorized ROEs for electric utility companies. The Commission notes witness Hevert's rebuttal testimony that the lowest authorized ROE for a vertically integrated electric utility since January 2014 was 70 basis points above witness Woolridge's 8.60% recommendation. The Commission cannot blindly follow ROE results allowed by other commissions, but must determine the appropriate ROE based upon the evidence and particular circumstances of each case. However, the Commission believes that the ROE trends and decisions by other regulatory authorities deserve some weight, as they provide a check or additional perspective on the case-specific circumstances. In addition, DNCP must compete with utilities in other jurisdictions for capital from investors. In this regard, the Commission finds persuasive witness Hevert's testimony at the hearing that North Carolina is generally viewed by the credit ratings agencies to be a supportive jurisdiction, and that an ROE of 9.90% is consistent with the returns recently awarded to utilities in similarly constructive jurisdictions. The Commission has not relied on this evidence to arrive at its ROE decision. Instead, the Commission has considered it as a check or as corroboration with regard to other evidence on ROE in this proceeding. That check allows the Commission to ensure that its ROE decision is not vastly out of line with rates of return authorized for regulated utilities in other jurisdictions. In addition, the Commission finds persuasive witness Hevert's responses to witness Woolridge and counsel for Nucor regarding the use of annual averages of the inputs to the DCF analysis and other inputs to his analyses. The Commission gives weight to witness Hevert's rebuttals to witness Woolridge's testimony as discussed above and the check on witness Woolridge's recommended ROE provided by the comparison to other similar jurisdictions. The Commission concludes that witness Woolridge's result of 8.6% ROE is outside the bounds of reasonableness – there is no credible evidence showing that the cost of equity for DNCP has decreased by 160 basis points since the Company's last rate case - and would put the Company at a significant disadvantage in competitive capital markets when attempting to raise capital needed to fund its operations.

The Commission gives little weight to witness O'Donnell's ROE testimony. The Commission find persuasive witness Hevert's responses to witness O'Donnell's' arguments regarding the long-term growth rate and other inputs to his analyses, particularly witness Hevert's discussion regarding the distinction between ROE and pension returns. The Commission agrees with witness Hevert that in light of the Hope case ruling that it is the end result that is the primary consideration in ROE determinations. In this case, witness O'Donnell's end result of a 9.0% ROE, at 120 basis points lower than the last authorized ROE for DNCP, overstates the decline in investors' required return, and therefore is outside the bounds of reasonableness and would put the Company at a significant disadvantage in raising capital needed to fund its operations. Witness O'Donnell provided no testimony as to the reasonableness of the multi-stage DCF model or its application in this proceeding other than with respect to the long-term growth rate.

Counsel for Nucor, CUCA and the Attorney General questioned witness Hevert about various aspects of his analyses; however, their cross-examination did not establish a persuasive basis for an ROE lower than 9.90%. The stipulated 9.90% ROE is itself 60 basis points lower than the 10.5% ROE recommendation resulting from witness Hevert's analysis. The stipulated 9.90% ROE is further corroborated by witness Hevert's hearing testimony that in only one case that he can recall has a commission authorized an ROE comparable to the 9.0% and 8.6% ROEs recommended by Nucor and CUCA, and but for a decrement applied in that case for unrelated reasons, the ROE in that instance would have been 9.5%. Again, while the Commission has not relied on this evidence to arrive at its ROE decision, it has considered it as a check or as corroboration with regard to other evidence on ROE in this proceeding that allows the Commission to ensure that its ROE decision is not vastly out of line with rates of return authorized for regulated utilities in other jurisdictions. Overall, the Commission finds the settlement testimony of witness Hevert and witness Hinton to be credible, substantial, and probative evidence that supports approval of a 9.90% rate of return on common equity for DNCP in this proceeding.

As discussed above, numerous customers provided testimony at the public hearings as to the impact that any rate increase would have, especially on those customers in DNCP's service area who are on fixed incomes. The Commission acknowledges and accepts as true the proposition that some percentage of DNCP's customers, particularly those living on fixed incomes, are economically vulnerable and may struggle to pay an increase in DNCP's rates granted in this docket. The Commission gives substantial weight to the public witness testimony as it undertakes to balance the interests of DNCP's customers with the Company's need to obtain financing on reasonable terms for the continuation of reliable electric service.

Conclusions on Return

The Commission has the obligation to reach its own independent conclusion as to whether the Stipulation is just and reasonable, fair to customers, the Company and its shareholders in light of changing economic conditions, and otherwise sufficient to satisfy the requirements of G.S. 62-133. In sum, the Commission finds and concludes for purposes of this case and after thoroughly and independently reviewing all of the evidence that an authorized ROE of 9.90% is just and reasonable based on all of the evidence presented.

The Commission understands that rate increases are not favored by ratepayers and that some portion of any utility's customer base will find it difficult to pay their utility bills from time to time. The Commission further acknowledges that it is the Commission's primary responsibility to protect the interests of utility customers in setting rates for public utilities by complying with the legal principles discussed earlier in this Order. It is also the Commission's responsibility to abide by the constitutional requirements of the Hope and Bluefield cases as reflected in the provisions of G.S. 62-133 and to balance the interests of customers and the regulated utilities.

The Commission finds and concludes, for the reasons set forth herein, that the ROE recommendations of witnesses Woolridge and O'Donnell are to be afforded little weight. The Commission concludes that their analyses would produce a significant risk that the Company could not obtain equity financing on reasonable terms. The Commission further concludes that a 9.90% ROE is reasonable based in part on probative, credible evidence from witness Hevert and witness Hinton. In particular, rather than accept any one approach of any single witness, the Commission has independently determined that the combination of witness Hevert's updated analytical results, as well as witness Hinton's updated comparable earnings results, are supportive of an ROE of 9.90%. The 9.90% ROE is also supported by the Stipulation and the accompanying testimony of DNCP and Public Staff witnesses as to its reasonableness. Finally, as discussed below in more detail, the Commission concludes that a 9.90% ROE is reasonable and appropriate in light of the numerous other adjustments that affect earnings available to investors. Such adjustments include reductions in the Company's requested rate base, reductions in its requested operating expenses, an approved capital structure that imputes a lower equity ratio than the Company's actual capital structure, and a $400,000 shareholder contribution to assist low-income customers. Along with these adjustments, the impact of changing economic conditions on DNCP's customers has been taken into account in determining the approved ROE.

Consumers pay rates, a charge in cents per kilowatt-hour for the electric energy they consume. They do not pay a rate of return on equity. To the extent that the Commission makes downward adjustments to rate base, reduces the approved common equity component of capital structure, disallows test year expenses or increases pro forma test year revenues, the Commission reduces the rates consumers pay during the future period rates will be in effect. However, the utility's investors' compensation for the provision of service to consumers takes the form of return on investment. To the extent the Commission makes adjustments to reduce the overall cost of service, the Commission reduces the rates consumers otherwise must pay irrespective of its determination of rate of return on equity expressed as a percentage, in this case 9.90%. To the extent these adjustments reflect current economic conditions, and consumers' ability to pay, these adjustments reduce not only consumers' rates but also the return on equity, expressed in terms of dollars that investors actually earn. This is also in accord with the end result test of Hope.

In the present case, DNCP's initial Application requested a $51.073 million increase in DNCP's annual North Carolina revenues. That revenue increase would require an overall rate increase of 20.90%. In addition, DNCP requested a 10.5% rate of return on common equity, a 7.88% overall return on a rate base of $1.067 billion, and a capital structure that included 53.359% common equity. In the Company's supplemental and rebuttal cases, it revised its requested revenue increase to $46.8 million and its overall return to 7.805%. These are the "big picture" numbers in the case. However, the crucial details of DNCP's general rate Application, as in all general rate cases, are in the hundreds of line items in the NCUC Form E-1 that detail the Company's cost of service. The details of DNCP's Application, including the cost of service line items, are reviewed by the Public Staff and by other intervenors. The Public Staff typically recommends numerous adjustments to the utility's cost of service items, some adjustments increasing an item and some adjustments decreasing another item. These adjustments are presented by the Public Staff in its testimony, or, as in the present docket, in a settlement agreement with the utility.

In the present docket, the Public Staff's adjustments are shown in Settlement Exhibit II of the Stipulation. There are about 20 adjustments, some up and some down. However, the end result of all the adjustments is a reduction in DNCP's revenue requirement from the $46.752 million requested in the Company's rebuttal case to the stipulated amount of $34.732 million. Thus, the numerous adjustments made by the Public Staff, and approved herein by the Commission, reduce the total annual base revenues to be received by DNCP from ratepayers by $12.020 million, including a reduction of approximately $5.235 million resulting from a decrease in the rate of return to be paid to equity investors.[17] Although the ROE downward adjustment produces a direct reduction in the authorized rate of return on investment financed by equity investors, the numerous other downward adjustments reflected on Settlement Exhibit II further reduce the dollars the investors actually have the opportunity to receive. For example, the authorized 51.75% equity ratio in the capital structure, which is a regulatory

[17] See Settlement Exhibit II.

reduction from the Company's actual equity ratio of 53.92%, reduces revenues available for earnings by another $2.849 million. Thus, while the equity investor's cost was calculated under the terms of the Stipulation by applying a rate of return on equity of 9.90%, instead of the 10.5% requested in the Application, this is only one of many approved adjustments that reduces ratepayer responsibility and equity investor reward.

This is not to say that the Commission accepts the stipulated 9.90% rate of return on equity merely because it is lower than the 10.5% requested by DNCP. Indeed, the Commission has weighed the evidence of the expert ROE witnesses, and in finding some of that evidence to be highly probative and other parts of that evidence as entitled to little weight, has independently found support in the analytical results for a 9.90% ROE. In addition, the Commission concludes that each of the approximately 20 adjustments made by the Public Staff, and accepted herein by the Commission, reflects the fact that ratemaking, and the impact of rates on consumers, must be viewed as an integrated process where the ratemaking end result is what directly affects customers. The Commission's acceptance of the foregoing ratemaking adjustments, including the 9.90% rate of return on equity, reflects the Commission's application of its subjective, expert judgment under the Public Utilities Act that the end result is in compliance with the Commission's responsibility to establish rates as low as reasonably possible without transgressing constitutional constraints.

Solely focusing on the authorized rate of return on equity in assessing the impact of the Commission's decision on consumers' ability to pay in the current economic environment would fail to give a true and accurate picture of the issues presented to the Commission for decision and the totality of the Commission's order. Such an analysis would also be inconsistent with Hope and the CUCA cases. For example, when the Commission approves a reduction in the investment (rate base) against which the authorized 9.90% rate of return on equity is multiplied to produce the dollars in return on equity investment, the financial impact is a reduction in the rates paid by ratepayers and a reduction in the amount received by equity investors, the same result as if the Commission had instead reduced the 9.90% rate of return on equity. In the present case, the Stipulation included a reduction of $4.903 million in authorized rate base, and therefore, a substantial reduction in revenues available to pay earnings to shareholders, compared to the Company's position in its rebuttal testimony.[18]

As previously noted from the Hope decision, it is the "end result" of the Commission's order that must be examined in determining whether the order produces just and reasonable rates. Consistent with that requirement, the Commission has incorporated into its analysis all of the myriad factors that make up DNCP's revenue requirement, including the rate of return on equity and the impact of the Commission's decision regarding the consumers' ability to pay in the current economic environment. With respect to customers' ability to pay, an important adjunct to the 9.90% ROE is the $400,000 shareholder contribution to assist low-income customers, notwithstanding the

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[18] See Fernald Exhibit 1, Schedule 2, Revised (filed with the settlement testimony of Public Staff witness Fernald).

significant improvement in economic conditions in DNCP's service territory since the Company's last rate case. Based on the impact on customers, the requirements of investors in capital markets, and the total effect of the Stipulation with its numerous reductions to the Company's proposed revenue requirement, the Commission concludes that a 9.90% rate of return on equity produces just and reasonable rates for DNCP and for its ratepayers. Any further reduction in the authorized rate of return on equity is not justified by any evidence that the Commission has found to be credible and probative in its fact finding role.

In separate post-hearing briefs, the AGO and Nucor emphasized the generally lower results produced by the Constant Growth DCF analyses of all the witnesses. They argue that either the implementation, or interpretation of results, by witnesses Hinton and Hevert in their Mutli-Growth DCF, Comparable Earning, Risk Premium, or CAPM analyses are flawed and excessive. The AGO, which presented no witness, recommends an ROE of less than 9.0%, and Nucor recommends an ROE of 8.6% consistent with the testimony of witness Woolridge.

In its post-hearing Brief, CUCA contends that the stipulated ROE of 9.90% is too high because it represents a "split the baby" approach between the ROE proposed by Public Staff witness Hinton and the ROE proposed by DNCP witness Hevert. Further, CUCA maintains that each of the analytical models used by witness Hevert is seriously flawed, as discussed by CUCA witness O'Donnell in his testimony.

After consideration of the entire record and for the reasons stated herein, the Commission is not persuaded by the AGO or Nucor that the 9.9% ROE in the Stipulation is excessive. The Commission points out that each of the witnesses to this proceeding use considerable judgement or discretion in deciding which ROE estimation method or model to use and present into evidence, or even withhold. In addition, each ROE witness used discretion in deciding what inputs to use within each method, the interpretation of the results of each method, and how the results of each method were weighted in determining the ROE to recommend on behalf of their employer or client. The Commission is uniquely situated and legally charged with using its impartial judgement to determine the ROE using applicable legal standards. The Commission has used its impartial judgment as necessary and appropriate to evaluate and weigh the evidence in reaching its conclusions and findings relevant to the ROE issue as set forth in this Order.

After a careful review of all the evidence in this case, and adhering to the requirements of the above cited legal precedents, the Commission finds that the overall rate of return on rate base and the allowed rate of return on common equity, as well as the resulting customer rates provided for under the Stipulation, are just and reasonable, fair to both DNCP and its customers, appropriate for use in this proceeding, and should be approved. The rate increase approved herein, as well as the rates of return underlying such rates, are just, reasonable and fair to customers considering the impact of changing economic conditions, and are required in order to allow DNCP, by sound management, to produce a fair return for its shareholders, maintain its facilities and provide services in accordance with the reasonable requirements of its customers in the territory covered by its franchise, and to compete in the market for capital funds on terms that are reasonable and that are fair to its customers and existing investors.

The Commission notes further that its approval of an ROE at the level of 9.90% - or for that matter, at any level - is not a guarantee to the Company that it will earn a return on its common equity at that level. As noted above, on June 30, 2016, the Company's fully-adjusted earned rate of return on equity capital for the update period was only 5.50%, far below the Company's currently authorized 10.2%. Rather, as North Carolina law requires, setting the ROE at this level merely affords DNCP the opportunity to achieve such a return. See G.S. 62-133(b)(4). The Commission believes, based upon all the evidence presented, that the ROE provided for here will indeed afford the Company the opportunity to earn a reasonable and sufficient return for its shareholders while at the same time producing rates that are fair to its customers.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 35

The evidence supporting this finding of fact and these conclusions is contained in the Application and Form E-1 of DNCP, the testimony and exhibits of the witnesses, the Stipulation, and the entire record in this proceeding.

In the Application and direct testimony and exhibits, DNCP provided evidence supporting an increase of $51.073 million, or approximately 20.90%, in its annual non-fuel revenues from its North Carolina retail electric operations. On August 12, 2016, the Company filed supplemental direct testimony and exhibits updating several cost of service adjustments. These updated adjustments decreased the Company's revenue requirement by $3.3 million, for a revised increase in North Carolina retail revenue of $47.8 million, which was reduced again in the Company's rebuttal case filed on September 26, 2016 to $46.8 million.

On September 7, 2016, the Public Staff filed the direct testimony of witness Fernald, presenting her recommended accounting and ratemaking adjustments to the Company's proposed revenue requirement. Accounting for these adjustments, she recommended an increase in the Company's annual base non-fuel operating revenue of $19,755,000. Nucor filed testimony of witness Kollen, who also made recommendations for accounting adjustments.

On September 26, 2016, the Company filed the rebuttal testimony of witness Stevens, which responded to the various accounting adjustments and recommendations of witness Fernald and witness Kollen.

On October 3, 2016, the Company, the Public Staff and CIGFUR I entered into and filed the Stipulation. Pursuant to the Stipulation, the Company, the Public Staff and CIGFUR I agreed upon an increase to DNCP's annual non-fuel revenue from its North Carolina retail electric operations of $34.732 million or 14.25% and a decrease in annual base fuel revenues of $8.942 million.

Also on October 3, 2016, the Company filed the joint testimony of witness Stevens and witness McLeod in support of the stipulated revenue increase. These witnesses testified in support of the accounting and ratemaking adjustments agreed upon in the Stipulation. They also testified that the Stipulation is the result of negotiations between the Stipulating Parties who, collectively, represent both residential and industrial customer interests impacted by this case. Also on October 3, 2016, the Public Staff filed testimony of witness Fernald recommending and supporting the stipulated adjustments to the Company's requested revenue increase.

Based upon the evidence recited above and the cumulative testimony and evidence supporting the individual components of the stipulated revenue increase discussed throughout this Order, the Commission finds, in the exercise of its independent judgment, that the stipulated net revenue increase of $25.70 million for North Carolina retail electric operations in this case is just, reasonable, and appropriate for use in this proceeding.

The following schedules summarize the gross revenue and the rate of return that the Company should have a reasonable opportunity to achieve based on the determinations made herein. These schedules, illustrating the Company's gross revenue requirement, incorporate the findings and conclusions made by the Commission in this Order. As reflected in Schedule I, and as impacted by the other findings in this Order, DNCP is authorized to increase its annual level of gross revenues by $25.790 million, reflecting an increase of $34.732 million in base non-fuel revenues (including late payment fees and other revenues) and a decrease of $8.942 million in base fuel revenues.

SCHEDULE I
DOMINION NORTH CAROLINA POWER
North Carolina Retail Operations
Docket No. E-22, Sub 532
STATEMENT OF OPERATING INCOME
For the 12 Months Ended December 31, 2015
(000's Omitted)

Item	Present Rates	Approved Increase	Approved Rates
Electric sales revenues	$242,718	$34,310	$277,028
Base fuel revenues	99,755	(8,942)	90,813
Late payment fees	1,292	92	1,384
Other revenues	6,167	330	6,497
Total operating revenues	349,932	25,790	375,722
Fuel expenses	90,686	0	90,686
Other O&M expenses	98,829	160	98,989
Depr. and amort. expense	60,047	0	60,047
Gain / loss on disp. of property	309	0	309
Taxes other than income	15,233	0	15,233
Income taxes	23,891	9,929	33,820
Total operating expenses	288,995	10,089	299,084
Net operating income before adj.	60,937	15,701	76,638
Interest on customer deposits	(19)	0	(19)
Interest on tax deficiencies	(1)	0	(1)
Net operating income for return	$ 60,917	$15,701	$ 76,618

SCHEDULE II
DOMINION NORTH CAROLINA POWER
North Carolina Retail Operations
Docket No. E-22, Sub 532
STATEMENT OF RATE BASE AND RATE OF RETURN
For the 12 Months Ended December 31, 2015
(000's Omitted)

Item	Present Rates	Approved Increase	Approved Rates
Electric plant in service	$1,947,252	$ 0	$1,947,252
Accumulated depr. and amort.	(716,858)	0	(716,858)
Net electric plant in service	1,230,394	0	1,230,394
Materials and supplies	44,91 6	0	44,916
Cash working capital	16,40 6	2,070	18,476
Other additions	19,607	0	19,607
Other deductions	(17,434)	0	(17,434)
Customer deposits	(5,126)	0	(5,126)
Acc. deferred income taxes	(250,799)	0	(250,799)
Rounding	1	0	1
Total original cost rate base	$1,037,965	$ 2,070	$1,040,035
Rate of Return	5.87%		7.37%

SCHEDULE III
DOMINION NORTH CAROLINA POWER
North Carolina Retail Operations
Docket No. E-22, Sub 532
STATEMENT OF CAPITALIZATION AND RELATED COSTS
For the 12 Months Ended December 31, 2015
(000's Omitted)

Item	Capitalization Ratio	Original Cost Rate Base	Embedded Cost	Net Operating Income
		Present Rates – Original Cost Rate Base		
Long-Term Debt	48.25%	$ 500,818	4.650%	$23,288
Common equity	51.75%	537,147	7.010%	37,629
Total	100.00%	$1,037,965		$60,917
		Approved Rates – Original Cost Rate Base		
Long-Term Debt	48.25%	$ 501,817	4.650%	$23,334
Common equity	51.75%	538,218	9.900%	53,284
Total	100.00%	$1,040,035		$76,618

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 36

The evidence for this finding of fact and these conclusions is contained in the Stipulation, the testimony of DNCP witness Stevens and Public Staff witness Fernald, and the entire record in this proceeding.

Section XV of the Stipulation provides that the Company will make a one-time $400,000 shareholder contribution over and above its usual contribution to its North Carolina EnergyShare program, which provides energy assistance to customers in need in the Company's North Carolina service territory, by March 30, 2017. At the hearing, the Company notified the Commission that it would commit to making this contribution no later than early January, 2017, so that the funds would be available for the winter heating season. Company witness Stevens testified that the Company's usual annual EnergyShare expenditure in North Carolina was approximately $360,000, so the amount agreed upon in the Stipulation would effectively double the amount of shareholder contribution to low-income heating assistance.

The Commission notes that the $400,000 shareholder contribution to low-income energy assistance is a feature of the settlement between the Company, the Public Staff and CIGFUR I that could not have been ordered by the Commission without the agreement of the Company. The Commission finds and concludes that this provision of the Stipulation is just and reasonable to all parties in light of all the evidence presented.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 37-41

The evidence supporting these findings of fact and conclusions is found in the Company's verified Application and exhibits, the Stipulation, and the testimony of Company witnesses Pierce (as adopted by Haynes), and Haynes, Public Staff witness Floyd, Nucor witness Goins, and CUCA witness O'Donnell, and the entire record before the Commission in this proceeding.

<u>Cost of Service Methodology</u> – The Company's Application, as supported by witness Haynes, used the SWPA cost of service methodology to allocate production and transmission plant costs for both the North Carolina jurisdiction and the North Carolina retail customer classes. The SWPA method recognizes two components of providing service to customers - peak demand and average demand - when determining the responsibility for costs of production and transmission plant and related expenses. The peak demand component takes into account the hour when the load on the system is highest during both the summer months and the winter months. The average demand component recognizes that there is a load incurred by the system over the course of all hours during the year. The average demand is determined based upon the total energy provided to the customers during the year divided by the total number of hours in the year. The average component is then weighted by the system load factor, and the peak component is weighted by one minus the system load factor. The load factor is calculated by taking the Company's actually experienced average demand divided by its actually experienced peak demand during the test year.

Witness Haynes explained that DNCP developed and presented in its Form E-1, Item 45, the "per books," annualized, and "fully-adjusted" jurisdictional and customer class cost of service studies (COSS) based on the SWPA allocation method for the 12-months test year ended December 31, 2015.[19] In developing the SWPA COSS, the Company also made an adjustment to the Company's recorded summer and winter peaks to recognize and add back the kW generated by non-utility generators (NUGs) interconnected to DNCP's distribution system that are not included in those values. This NUG adjustment addresses a "mismatch" between the peak and the average components of the SWPA, as the kWh generated by distribution-interconnected NUGs were included in the average demand component of the SWPA but not in the summer and winter peak component. The NUG adjustment was calculated by determining the actual kW generated by distribution-interconnected NUGs at the time of the summer and winter peaks in both DNCP's Virginia and North Carolina service territories, and then adding these "state" values to each jurisdiction's respective recorded summer and winter peaks to arrive at the adjusted level. DNCP's fully adjusted SWPA COSS produced a North Carolina jurisdictional allocation factor of 5.1166%.

Company witness Haynes testified that the objective of jurisdictional and customer class cost of service studies is to determine the allocation of a share of the system's revenues, expenses, and plant related to providing service across multiple jurisdictions. Certain items can be assigned directly to the jurisdiction and classes based on the utility's records, but other items are not directly assignable and must be allocated. Witness Haynes stated that in this proceeding, the Company allocated its production and transmission plant and expenses using the SWPA cost of service methodology. He noted that the Commission has approved DNCP's use of the SWPA method in five other general rate case proceedings for the Company, dating back to 1983, including the 2012 Rate Case.

Company witness Haynes testified that the SWPA allocation method is consistent with the manner in which DNCP plans and operates its system. Specifically, the "Summer and Winter" peak component recognizes the total level of generation resources necessary to serve the system peaks while the average component recognizes the type of generation serving customers' energy needs year-round.

Company witness Haynes also emphasized that use of a single peak or other peak-only methodology could allow certain customer classes that have zero demand during the peak hour(s) of the year to fully avoid responsibility for production plant costs. Witness Haynes explained that a common example is that streetlights normally do not operate during peak hours. Company witness Haynes also highlighted the NS Class as another example unique to DNCP's North Carolina jurisdictional load. Witness Haynes explained that Nucor, the only customer in the NS Class, has an average annual demand

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[19] At the request of CIGFUR I and Nucor in discovery, and in response to the Commission's March 17, 2016 Order Denying Motion and Granting Alternative Relief, DNCP also developed and filed with the Commission a per books single coincident peak (1CP) COSS on May 31, 2016. The DNCP 1CP COSS is designed using only the single highest system peak during the test year, and produced a per books North Carolina jurisdictional allocation factor of 5.2354%.

throughout the year of approximately 100 megawatts (MW), while Nucor's average of its summer (June 2015) and winter (February 2015) coincident peak demands is approximately 42 MW. Witness Haynes explained that without recognizing an average component in the cost allocation, this customer class would "pay" for only 42 MW and escape cost responsibility for an average of 58 MW for the rest of the year (i.e., the average demand of 100 MW less the allocated demand of 42 MW). Witness Haynes explained that by recognizing both the energy needed to serve load at the peak hour, as well as energy consumed throughout the year, the SWPA method allocates some portion of these system costs to all customers, including those customers that can reduce their peak demand and those that may not place a demand on the system during the respective summer and winter peak hour. Such customers still use and receive the benefit of the Company's investments in production assets by paying lower energy costs, specifically fuel costs, during all other hours.

Public Staff witness Floyd agreed with the Company's use of the SWPA cost of service methodology in this proceeding because it appropriately allocates the Company's production plant costs in a way that most accurately reflects the Company's generation planning and operation. He testified that unlike other methodologies that allocate all of the production plant costs based on a single coincident peak or on a series of monthly peaks, the SWPA methodology recognizes that a portion of plant costs, particularly for base load generation, is incurred to meet annual energy requirements throughout the year and not solely to meet peak demand at a particular time. Witness Floyd also addressed the NUG adjustment to SWPA, stating that the Public Staff agrees with DNCP's adjustment as appropriately recognizing the impact that distribution connected NUGs have on DNCP's system.

Nucor witness Goins recommended that the Commission reject DNCP's use of the SWPA method and, instead, order DNCP to use the Summer-Winter Coincident Peak (S/W CP) method. Witness Goins developed and filed a fully adjusted S/W CP COSS that incorporated the cost-of-capital and ratemaking adjustments proposed by Nucor witnesses Woolridge and Kollen, respectively.

Witness Goins suggested that the use of the SWPA method is unreasonable because the SWPA methodology is used in almost none of the regulatory jurisdictions with which he was familiar. He further argued that the SWPA method is flawed for a number of reasons and ultimately allocates a greater portion of DNCP's cost of service to Nucor and other high load factor customers. Specifically, witness Goins argued that Nucor's load is totally interruptible and, therefore, should be excluded when deriving the SWPA allocation factors. Witness Goins contended that in failing to properly recognize Nucor's interruptible load, the Company overstated the cost to serve Schedule NS and understated the rate of return for Schedule NS. Finally, witness Goins argued that the use of SWPA harms Nucor and other high load factor customers who would be assigned lower levels of fixed production costs under a peak-only methodology.

Nucor witness Goins testified that should the Commission continue to find the SWPA method appropriate for use in this proceeding, the Commission should reject the system load factor weighting methodology used by DNCP and, instead, use a weighting that allocates a greater percentage of production costs based using peak demand and a lesser percentage based upon the average energy-based demand component. Specifically, witness Goins suggested that DNCP's system load factor weighting is heavily biased towards energy and suggested that the Commission could mitigate the bias by establishing weighting for the peak demand component at 75% or greater and the average demand component at 25% or less.

CUCA witness O'Donnell's arguments in support of the 1CP methodology were similar to those of witness Goins in support of S/W CP. Witness O'Donnell suggested that 1 CP best depicts how DNCP dispatches its plant to meet peak load. He further argued that he opposed SWPA because it sends the message to industrial consumers to use less energy and for residential and small consumers to use more energy, which will hurt manufacturing and economic development in Eastern North Carolina and, in time, raise rates to the residential and small commercial consumers when industrial consumers that cannot afford the higher rates move their operations elsewhere or simply close altogether.

In rebuttal, Company witness Haynes extensively addressed and rebutted the cost of service arguments of witness Goins on behalf of Nucor and witness O'Donnell on behalf of CUCA. Witness Haynes explained that the SWPA method reasonably and appropriately recognizes the two components of providing service to customers, peak demand, and average demand, and is consistent with the manner in which the Company's planning department plans for and meets DNCP's system needs, taking into consideration the need to meet both peak demands and the need to provide resources that can be operated to serve customers throughout the year. The "Summer and Winter" peak component recognizes the total level of generation resources necessary to serve the system peaks, while the average component recognizes the dispatch of different types of generation providing the system with low cost energy year-round. Witness Haynes pointed to the Company's recent additions of the intermediate/baseload gas-fired combined cycle 1,342 MW Warren County CC and the 1,358 MW Brunswick County CC (as well as the Company's historical investments in its baseload nuclear fleet) as production-related plant operated throughout the year to provide baseload energy to the Company's customers.

Witness Haynes responded to Nucor witness Goins' suggestion that SWPA is a rarely used methodology by explaining that there are numerous other jurisdictions, including the Company's Virginia jurisdiction, that include an "average" (energy) component in the development of production allocation factors. The Company operating in Virginia as Dominion Virginia Power has used the Average & Excess (A&E) cost allocation method in every Virginia rate proceeding dating back to 1972. Witness Haynes also testified that the SWPA and A&E methods have the benefit of also being relatively consistent (both include energy components) and, further, that preserving historical continuity in the method used to allocate costs will also avoid significant shifts in allocated costs to a given class between one rate case and the next.

In addressing the peak-only S/W CP and 1CP methods advocated by witnesses Goins and O'Donnell, witness Haynes explained that these methodologies are unreasonable and inappropriate for DNCP because their reliance on the single coincident peak hour or only the two hours of DNCP's summer and winter peaks is inconsistent with the way DNCP plans and operates its system to both meet the system peaks as well as to deliver low cost energy throughout the year. In addition to the new Warren County and Brunswick County Power Station investments, described above, witness Haynes also specifically pointed to the remaining $4.7 billion of nuclear plant in service at the end of 2015, which still represents approximately 30% of DNCP's total production plant investment. Witness Haynes also presented concerns that use of S/W CP would produce unreasonable results in other areas of DNCP's COSS, such as production plant O&M expenses.

Witness Haynes also presented a number of analyses showing that moving from a SWPA methodology to the S/W CP methodology would cause a significant shift of DNCP's cost of service between the classes and would shift recovery of production costs away from Nucor and other high load factor customers and to the residential class. For example, witness Haynes' analysis in his Rebuttal Table 4 showed that the NS Class rate of return increased from approximately 2% under the SWPA method to approximately 18% under Witness Goins' S/W CP method. Witness Haynes' Rebuttal Table 5 presented the shift in class rate of return indices (RORI) between SWPA and S/W CP, with the Schedule NS Class increasing from 0.40 under SWPA to 2.79 under the S/W CP method (an increase of over 597.5 %), while the residential class fell from a RORI 0.97 under the SWPA method to 0.65 under witness Goins' S/W CP method. Witness Haynes also noted that under the fully adjusted cost of service presented by witness Goins, the residential class would receive a $24.8 million increase to achieve the overall jurisdiction S/W CP ROR.

Witness Haynes explained that witness O'Donnell's 1CP method is unreasonable for the same reasons as the peak only S/W CP method. Witness Haynes testified that 1CP also fails to take into consideration both the summer and winter peaks as DNCP is forecasted to remain a summer peaking utility, but recently experienced all-time system peaks during the winter in 2014 as well as during the 2015 test year. Finally, witness Haynes testified that use of the 1CP method would also increase cost responsibility for the North Carolina jurisdiction, while lowering the rate of return for the jurisdiction, and would also significantly shift costs to the residential class compared to the SWPA method.

Witness Haynes also explained that DNCP's continued use of the test year system load factor is a reasonable, reliable, and consistent method for establishing the weighting of the peak and average components of the SWPA COS methodology. Contrary to witness Goins' view, the Company's use of the system load factor is not arbitrary, but is based on DNCP's actual verified usage of the Company's generation capacity throughout the course of the test year relative to installed capacity. Witness Haynes testified that witness Goins' recommendation to weight the peak demand at 75% and the average demand at 25% is both arbitrary and results oriented as it would have the effect of increasing the residential class' percent of system responsibility for production costs by 13.8% and decreasing the cost responsibility allocated to Nucor by 35.2%.

Finally, witness Haynes argued that the Commission's recent decision in Duke Energy Progress' 2013 rate case adopting a 1CP method for that utility, should not have bearing on the Commission's determination of the appropriate allocation methodology for DNCP. Witness Haynes pointed out that the Commission explained in its Order in the Duke Energy Progress 2013 rate case that cost allocation does not lend itself to a "one size fits all approach."[20] Witness Haynes also emphasized that the use of S/W CP or another peak only method is potentially more significant for DNCP than other utilities due to the Company's obligation to serve a "one-customer industrial class" – Schedule NS – which used approximately 19% (863,206,000) of the 4,568,385,000 jurisdictional kWh during the test year but can also significantly reduce its demand on the peak.

Under cross-examination by CUCA, witness Haynes accepted that adopting a peak-only methodology such as S/W CP or 1CP would allocate a significantly lower amount of cost responsibility to large high load factor customers, but argued that these methodologies would also cause a shift in cost responsibility to the residential and other non-industrial rate classes. He testified that using only one or two hours of the year to determine cost responsibility is not consistent with the way DNCP plans and operates its generation plants, nor is it fair from a cost allocation perspective, especially considering smaller general service and residential customers. During cross-examination by Nucor's counsel, witness Haynes disagreed with witness Goins' alternative weighting of the SWPA demand and energy components at 75% demand and 25% energy, explaining that his rebuttal Schedule 1 analysis showed that this modified weighting would make residential cost responsibility go up by 13.8%, while Nucor would receive a minus 35.2% shift in cost responsibility and the 6VP class would have a negative 28.9% shift in responsibility under this weighting. On redirect, witness Haynes identified other jurisdictions that use average components in allocating production costs but stated that the Company had not completed an exhaustive assessment of every jurisdiction and utility in the country. He also testified that while it is up to the Commission to determine the weightings in SWPA, the Commission has previously determined that the use of the system load factor was an appropriate way to weight the average demand component, and one minus that system load factor was an appropriate way to weight the peak demand component.

In its post-hearing Brief, CUCA contends that use of the SWPA methodology, as opposed to the 1CP, results in a rate design that sets higher rates than required for large industrial customers. Further, CUCA notes that the Commission has approved the use of 1CP for Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC.

The Commission finds and concludes that DNCP has carried its burden of proof to show that the SWPA methodology is the most appropriate cost of service methodology to use in this proceeding to assign cost responsibility for production plant to the North Carolina jurisdiction and the Company's customer classes. On this issue, the Commission gives substantial weight to the testimony of Company witness Haynes and Public Staff

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[20] Application of Progress Energy Carolinas, Inc., Docket No. E-2, Sub 1023, Order Granting General Rate Increase, at 98 (May 30, 2013).

witness Floyd. The cost of service methodology employed in establishing an electric utility's general rates should be the one that best determines the cost causation responsibility of the jurisdiction and various customer classes within the jurisdiction based on the unique characteristics of each class's peak demands and overall energy consumption. Company witness Haynes testified extensively that the Company's investment in generating plant, including the recently placed in service Warren County CC and Brunswick County CC, are designed to meet the Company's system peaks and to deliver low cost energy throughout the year. Witness Haynes explained that the SWPA methodology appropriately recognizes that DNCP's system planning is designed to meet both the Company's peak and average system demands and energy needs of customers throughout the year. Both Company witness Haynes and Public Staff witness Floyd testified that the SWPA method appropriately matches allocation of production plant with DNCP's generation planning and operations. The Commission finds that, for purposes of this proceeding, the SWPA cost of service methodology properly recognizes the manner in which DNCP plans and operates its generating plants to provide utility service to customers in North Carolina.

The Commission also recognizes and reaffirms its prior determination in the Duke Energy Progress 2013 rate case that cost allocation does not lend itself to a "one size fits all approach."[21] Based on the facts in this case, a methodology that does not properly consider the effect of overall energy consumption, but focuses mainly on peak responsibility would not properly represent the way in which the Company plans for and provides its utility service and the way customers use that service.

The Commission is not persuaded that either the S/W CP methodology or the 1CP methodology is appropriate for the Company in this proceeding. Company witness Haynes and Nucor witness Goins provided calculations to compare the rates of return associated with the cost of service methodologies they advocated. The disparity between allocation factors for peak demand-related factors and energy-related factors is apparent for each methodology, with the SWPA resulting in the most equitable sharing of the rate of return among DNCP's customer classes in this case.

In Nucor's Brief, Nucor reiterated witness Goins' testimony that (1) the Commission should abandon the SWPA methodology, (2) the Commission should adopt the S/W CP methodology, and (3) if the Commission decides to adopt SWPA, it should address two flaws/biases inherent in DNCP's SWPA cost studies. The two flaws alleged by Nucor are (1) energy use is given too much weight, 56%, because peak demand is the primary driver of DNCP's need for additional capacity, and (2) DNCP's use of SWPA creates an asymmetry in DNCP's assignment of fixed production cost responsibility and its average cost recovery of fuel costs.

With regard to increasing the weight assigned to peak demand, Nucor recommends giving a 25% weight to the average demand component and a 75% weight to the peak demand component. In support of this recommendation, Nucor cites the

[21] Id.

decisions of the Michigan Public Service Commission in two 2015 dockets, one involving DTE Electric Company (Case No. U-17689, Opinion and Order dated June 30, 2015), and the other Consumers Energy Company (Case No. U-17688, Opinion and Order dated June 30, 2015) (collectively, Consumers). Pursuant to Michigan statutory provisions, a 50-25-25 (50% peak demand, 25% on-peak energy use, 25% total energy use) cost allocation method is mandated, unless a party shows that an alternative method would better ensure that rates are equal to cost of service. The purpose of the Consumers proceeding was to determine whether a change in the energy/demand ratios mandated by the statute was warranted. Consumers Energy proposed a 4CP 100-0-0 methodology, whereby costs would be allocated based 100% on peak demand. However, the PSC Staff recommended a 75-0-25 methodology, which the PSC ultimately adopted. The PSC cited extensive evidence on the appropriate allocation formula, stating

> [T]he Commission therefore finds that the Staff's proposal to modify the production cost allocation method from 50-25-25 to 75-0-25 is well supported, better ensures rates are equal to cost of service, and should therefore be approved.

Id., at p. 17.

The Commission is not persuaded on the present record that the Michigan PSC's approach advocated by Nucor should be adopted for DNCP. For reasons perhaps unique to Michigan, the legislature has mandated that the Michigan PSC use a 50-25-25 cost allocation ratio, unless a better methodology is shown. In contrast, DNCP established its 56%-46% ratio based on DNCP's system load factor test-year data. That process is a more direct and accurate approach than the "one size fits all" ratio mandated in Michigan's statute. In addition, Nucor did not support its 25%-75% allocation weighting proposal with sufficient analyses of DNCP's system operating characteristics.

As a result, the Commission is not convinced that Nucor witness Goins' proposal to reject the Company's use of the system load factor and to adopt Nucor's alternative proposal to establish weighting for the peak demand component at 75% or greater and the average demand component at 25% or less is reasonable or appropriate in this proceeding. Nucor's rationale for this modified SWPA method is that reweighting SWPA to shift significantly greater emphasis to the peak demand component would mitigate the "numerous flaws" that Nucor finds in the SWPA method. Because the Commission finds that the SWPA method is not unreasonable or flawed, the Commission does not find Nucor's argument persuasive. Further, based on the evidence of record in this case, the Commission finds that the system load factor is not arbitrary, but is reasonably based on DNCP's actual verified usage of its Company's generation capacity throughout the course of the test year relative to installed capacity. Nucor's request that the Commission select weighting with a peak demand component of 75% or greater and the average demand component at 25% or less would be unreasonable and, indeed, arbitrary as it is not tied to any objective measurement of DNCP's system operations.

Based on the Stipulation and the testimony on the record, the Commission also finds that including the distribution-interconnected NUG generation in the average portion of the SWPA, but not including this NUG generation in the Company's recorded summer and winter peaks creates a mismatch between the peak and average components of the Company's SWPA COSS. The Commission concludes that the Company's adjustment to the summer and winter peaks to recognize the NUG generation at the distribution level appropriately recognizes the impact the NUGs have on DNCP's utility system and should be approved.

Finally, it is also notable that CIGFUR I joined in the Stipulation with DNCP and the Public Staff supporting the SWPA methodology as reasonable and appropriate in this proceeding. Although CIGFUR I has historically opposed the use of a production plant allocation methodology based on jurisdiction and customer class energy usage, it is not unreasonable for the Stipulating Parties to have agreed, as part of their overall settlement of all contested issues, that the allocation of production plant based on the SWPA methodology is reasonable for purposes of this proceeding. As the Commission has noted, that is part of the give-and-take of settlement negotiations. Therefore, based upon consideration of the Stipulation in its entirety, the Commission gives the Stipulation substantial weight in resolving the cost allocation methodology issue.

Based on the evidence in this proceeding, including the Stipulation, the Commission finds and concludes that the greater weight of the evidence shows that the SWPA cost of service methodology provides the most appropriate methodology to assign fixed production costs by incorporating DNCP's seasonal peak demands at the two single hours they occur and by incorporating the total energy consumed by the jurisdiction and customer classes over all the other hours of the year. In addition, the Commission finds good cause to require that the Company should continue to file a cost of service study using the SWPA methodology annually with the Commission.

Further, the Commission emphasizes the importance of properly allocating costs between jurisdictions, and specifically in this case between Virginia and North Carolina, and between customer classes. In that regard, the Commission takes note of Company witness Haynes rebuttal testimony that "The Company has used the A&E cost allocation method in every Virginia rate proceeding dating back to 1972. The 'average' portion of the A&E method is similar to the 'average' portion of the SWPA method." (T Vol. 7, at p. 193) However, even though the "average" portion of the A&E method is similar to the "average" portion of the SWPA method, the Commission finds good cause to require the Company to file an A&E cost allocation methodology in its next North Carolina general rate case, in addition to the methodology proposed by the Company.

Finally, the Commission notes that there is ample opportunity under Commission rules for thorough consideration of all issues related to cost of service in a general rate case. Interested parties may intervene, conduct discovery and present evidence in accordance with the rules of practice and procedure established by the Commission.

Treatment of Nucor in the Company's Cost of Service

The Company's SWPA cost of service study (Form E-1, Item 45) followed the same approach for the Schedule NS customer class (NS Class), as well as all other classes, used in the cost of service studies filed and approved in DNCP's two most recent general rate cases, Docket No. E-22, Sub 479 in 2012 and Docket No. E-22, Sub 459 in 2010. Specifically, as described by Company witness Haynes, the Company used both a summer and winter peak demand for the NS Class that reflected Nucor's measured demand and recognized the interruptible nature of Nucor's arc furnace pursuant to the confidential terms and conditions of the Company's contract with Nucor, the only customer in the NS Class. The 43 MW of peak demand assigned to the NS Class represents the average of the winter and summer peaks of the NS Class at the time of the test year system winter and summer peaks. These peak demands were used to develop the production plant and transmission related demand allocation factors. The Company also used Nucor's actual test year energy consumption of 863,206,000 kWh to develop the average component of SWPA.

In addition to his alternative COSS recommendations, addressed above, Nucor witness Goins argued that Nucor's total load is "non-firm" or interruptible pursuant to the Company's contract with Nucor for electric service and recommended that the Commission reject DNCP's treatment of Nucor's interruptible load in its cost of service study. Witness Goins disagreed with DNCP's characterization that Nucor's load continues to be partially interruptible under the Nucor agreement and argued that rates for service to fully interruptible customers should not recover any fixed production costs.

Witness Goins asserted that because Nucor's load is interruptible, it is not responsible (except by administrative fiat) for DNCP's fixed production costs. He concluded that service to Nucor's interruptible load occurs only when excess capacity used to serve firm load is available. Witness Goins further argued that DNCP's SWPA method allocates fixed production costs to Nucor almost exclusively based on Nucor's energy use. In contrast, about 60% of fixed production costs allocated to North Carolina customers in DNCP's cost studies is allocated on the basis of energy. Witness Goins recommended that if the Commission adopts DNCP's SWPA method, then the Commission should also replace DNCP's system load factor weighting scheme with peak demand component weights equal to or greater than 75% and average demand component weights of 25% or less, and further require DNCP to: (1) investigate the SWPA's asymmetrical allocation problem, including the preparation and filing for review of a detailed analysis of the problem similar to the analysis the Commission ordered in Docket No. E-22 Sub 333 (1994 Fuel Study); and (2) require DNCP in future jurisdictional and class cost studies to exclude Nucor's interruptible load in developing allocation factors for fixed production costs.

In rebuttal, Company witness Haynes explained the Company's reasoning for characterizing the Nucor agreement as partially interruptible as well as for the Company's treatment of Nucor in DNCP's COSS. Witness Haynes stated that Nucor's total load is only subject to interruption during system emergencies, when all other customers' load is also subject to interruption. Witness Haynes testified that the confidential terms of the Nucor agreement only allow for curtailment of Nucor's arc furnace load during very limited hours and, in certain of those hours, allow Nucor to buy through the curtailment at a higher price. Witness Haynes stated that the Company reads and applies the Nucor agreement to require Nucor's non-furnace load to be treated as "firm" and supplied with firm power throughout the year. Company witness Haynes also testified that he reviewed Nucor's actual loads since DNCP's 2012 Rate Case and confirmed that Nucor's non-furnace load has not been interrupted for emergency situations during at least that period.

Based on his understanding of the terms of the Nucor agreement as well as DNCP's implementation of the agreement since at least 2012, witness Haynes stated that DNCP's SWPA method properly takes into account Nucor's interruptibility, while also recognizing the demands Nucor places on the system and the energy consumed by Nucor. Nucor's average Summer/Winter coincident peak demand was approximately 43,192 kW during the test year, which represented the non-furnace load that the Company maintains is load that was actually served during the summer and winter peak hours. With regard to the average demand component, the Company has an obligation to serve Nucor each hour of the year and such a requirement is measured by the energy consumed. If Nucor is interrupted in any hour, then the energy consumption for that hour would reflect the interruption. Nucor actually consumed approximately 19% (863,206,000) of the 4,568,385,000 jurisdictional kWh during the test year. Witness Haynes asserted that the average demand component should reflect Nucor's actual use of the dispatch of the system generation and purchased power – just as is the case for all other customers.

Witness Haynes also performed an analysis detailing how recognizing Nucor's curtailed demand in developing the allocation methodology provides a significant and properly recognized financial benefit to Nucor as well as a lower overall allocation of system costs to the North Carolina jurisdiction. He asserted that the Company's SWPA allocation factors were calculated in a reasonable manner – consistent with the principles approved in DNCP's 2012 Rate Case – that appropriately recognizes the value of Nucor's interruptibility to the system and does not overstate cost nor understate returns for the North Carolina jurisdiction and its customer classes. Cost responsibility has been properly and fairly determined based on requirements placed on the system – by Nucor and all other customer classes – on the summer and winter peak days and throughout the year.

Witness Haynes also explained that the Commission is reviewing the same curtailment provisions that it reviewed in 2012 when it determined that the Company's SWPA method properly recognized Nucor's interruptible load under the Nucor agreement.

In response to Nucor's recommendation that the Commission require DNCP to exclude 100% of Nucor's load as interruptible in developing allocation factors for fixed production costs in future jurisdictional and class COSS, witness Haynes explained that this recommendation is inappropriate and, in effect, would treat the Schedule NS Class as if it did not exist. Witness Haynes explained that such an approach would be inconsistent with the manner in which DNCP has provided service to Nucor since the 2002 amendment to the Nucor agreement, when Nucor requested to transition from marginal cost of fuel and no assigned production plant to average cost of fuel for all system production resources. Haynes explained that if a customer once paid marginal cost and a small margin contributed toward production plant and related costs and now pays a more "certain" average fuel cost, then it should also be responsible for production plant costs – similar to all other customers.

Witness Haynes also reiterated that the provisions of the operative Nucor agreement giving Nucor the benefit of average fuel today are identical to the provisions of the Nucor agreement the Commission reviewed in 2012, when the Commission stated on page 30 of its Order as follows:

> The Commission also notes that the 2002 amendment to the Nucor contract to change the pricing structure was made at the request of Nucor. Nucor sought certainty in its pricing arrangements. Nucor therefore opted for a pricing arrangement that was based on the average fuel costs of the system, rather than the marginal cost pricing structure it had been receiving since the inception of the contract. ***The Commission agrees with the Company that under such an arrangement Nucor elected to receive the benefit of average fuel costs, and in doing so it also should be responsible for a share of the fixed production costs required to produce those same average fuel costs.*** The Commission further notes that the Nucor contract filed in the 2010 general rate case, Docket No. E-22, Sub 459, and in this proceeding no longer contains the language relieving the Company of any responsibility to provide for capacity to serve Nucor. (Emphasis added.)

In opposition to witness Goins' recommendation that Nucor be treated as 100% interruptible in future cost of service studies, witness Haynes concluded that Nucor actually consumes energy produced by DNCP equivalent to the energy needs of 71,000 residential households and because the NS Class is using production plant, it should contribute to fixed costs.

Based on the entire record in this proceeding, including the Stipulation, the Commission is persuaded that the Company has treated the NS Class and Nucor appropriately in its cost of service study and that no additional recognition of the benefits associated with the Nucor contract should be made in this proceeding.[22]

The facts and evidence in this proceeding show that the Company has consistently followed the same approach in this case of recognizing the benefits of Nucor's interruptibility – to both Nucor and the North Carolina jurisdiction – consistent with DNCP's

[22] In arriving at this conclusion, the Commission takes judicial notice of its most recent general rate case order for DNCP, issued on December 21, 2012 in Docket No. E-22, Sub 479. Specifically, the Commission recognizes its findings and conclusions regarding the interruptibility provisions of the Nucor Agreement and Schedule NS in that proceeding, which were ultimately affirmed on appeal by the North Carolina Supreme Court in State ex rel. Utils. Comm'n v. Cooper, 367 N.C. 430, 758 S.E.2d 635 (2014).

approach in the Company's past two general rate case proceedings. Further, the record in this case is undisputed that the curtailment provisions in the Nucor agreement have not been modified since last reviewed by the Commission in 2012. The Commission again concurs with the Company, Nucor, and Public Staff witnesses that the system, and the NS Class in particular, benefits from only recognizing Nucor's non-arc furnace load in calculating the peak load of the NS Class in the cost of service. Nucor's contract with the Company provides Nucor with flexibility in deciding how and when it consumes energy for the vast majority of hours in the year. Outside of the relatively few hours the Company can contractually request Nucor to curtail its arc furnace load, Nucor is free to buy through all other requests at a fixed price arrangement. The Company's testimony that Nucor's non-furnace load has not been interrupted since at least 2012 is also undisputed. Accordingly, based upon the facts and evidence presented in this case, the Commission does not find Nucor's arguments that the Nucor agreement is totally interruptible to be persuasive nor does the Commission find that Nucor should be treated differently than other customer classes and relieved of paying for its allocated share of DNCP's investment in production plant.

The Commission also again notes that the 2002 amendment to the Nucor contract to change the pricing structure was made at the request of Nucor. Nucor sought certainty in its pricing arrangements. Nucor therefore opted for a pricing arrangement that was based on the average fuel costs of the system, rather than the marginal cost pricing structure it had been receiving prior to 2002. The Commission agrees with the Company that under its current contractual arrangement Nucor has elected to receive the benefit of average fuel costs, and in doing so, it also should be responsible for a share of the fixed production costs required to produce those same average fuel costs. The Commission further notes that the Nucor contract, most recently approved by the Commission in Docket No. E-22, Sub 517, no longer contains the language relieving the Company of any responsibility to provide for capacity to serve Nucor as was the case of the Nucor contract prior to 2010. As the Commission describes below, the Nucor contract provides Nucor the right to continue to receive this partially interruptible service or to work with DNCP to move to another generally available rate schedule.

Based on the same reasons that service to Nucor should not be treated as 100% interruptible in developing the North Carolina cost of service used in setting just and reasonable rates in this case, the Commission finds and concludes that it would similarly be unreasonable and inappropriate to direct DNCP to make this assumption in future cost of service study filings with the Commission, unless the contract with Nucor is significantly altered such that it supports that position.

Fuel Study

In his testimony, Nucor witness Goins asserted that use of the SWPA methodology creates a mismatch in allocating fixed production costs and variable fuel costs. He stated that because high load factor customers are allocated a disproportionate share of DNCP's fixed production costs, they should also be allocated a disproportionate share of cheaper energy costs associated with the higher cost capacity. Instead, DNCP allocated average fuel costs on the basis of class loss-adjusted energy use. In other words, higher load factor classes get the higher baseload plant costs, but not the corresponding savings from lower baseload fuel costs. Witness Goins noted that in the 1994 Fuel Study, DNCP concluded that traditional average fuel cost recovery is not symmetrical with the way the LGS class is allocated production-related cost under the SWPA method. He recommended that the Commission require DNCP to prepare and file a detailed analysis similar to the analysis undertaken in the 1994 Fuel Study.

Witness Haynes testified in opposition to witness Goins' recommendation that DNCP be required to develop a new analysis similar to the 1994 Fuel Study. He explained that all customers, including residential and large industrial, benefit when the utility's system of available generating resources is operated such that the units with the lowest possible variable cost (mostly fuel) are dispatched to serve customer loads not just in the summer and winter peak hours, but in all hours of the year. This lowers fuel expenses recovered through the fuel clause. The capability to lower fuel expenses throughout the course of the year by system dispatch is accomplished by having available resources to efficiently serve utility loads during all hours and not only during the summer and winter peak hours. If all classes of customers are effectively paying "average fuel cost," then all customers are getting the benefit of the integrated system operation of the full range of generation resources from high capital cost/low operating cost generation to low capital cost/high operating cost generation.

Witness Haynes further testified that the SWPA method produces reasonable results by considering two seasonal peaks and the average demand and appropriately weighting both. DNCP's system load factor is approximately 56%, so the peak demand component is weighted at 44% in calculating the final total allocation factor. Witness Haynes stated that with this 44% weighting of the average of the winter and summer peaks and the ability of high load factor classes in North Carolina to reduce load during peak hours, such customers can reduce, and do reduce, their responsibility for fixed production costs. Witness Haynes testified that this a fair and reasonable approach to determining responsibility for fixed costs while paying average fuel. Witness Haynes therefore testified that there was no reasonable basis for the Commission to require the Company to "re-do" the 1994 Fuel Study.

Witness Haynes also testified during the hearing that DNCP has developed new industrial rate designs since 1994, such as Schedules NS and 6VP that allow high load factor classes in North Carolina to reduce load during peak hours, which has the effect of reducing these customer classes' responsibility for fixed production costs under the Company's SWPA method.

In Nucor's Brief, Nucor reiterated witness Goins' testimony that DNCP's use of SWPA creates an asymmetry in DNCP's assignment of fixed production cost responsibility and its average cost recovery of fuel costs. Witness Goins testified that because higher load factor customers are allocated a disproportionate share of DNCP's fixed production costs (including the higher cost of intermediate and baseload generating plants) under the SWPA methodology, they also should be allocated a disproportionate share of cheaper energy costs associated with the higher cost capacity. According to witness Goins, fixed production costs and variable fuel costs are not allocated symmetrically in DNCP's cost studies.

However, the Commission gives significant weight to the rebuttal testimony of DNCP witness Haynes. He testified that all customers, including residential and large industrial customers, benefit by DNCP's method of dispatching its generating resources such that the units with the lowest possible variable cost (mostly fuel) are dispatched to serve customer loads not just in the summer and winter peak hours but in all hours of the year. This lowers fuel expenses that are recovered through the fuel clause. Witness Haynes stated that the capability to lower fuel expenses throughout the course of the year by system dispatch is accomplished by having available resources to efficiently serve utility loads during all hours of the year, not solely during the summer and winter peak hours. He asserted that when all classes of customers are effectively paying "average fuel cost" determined in fuel clause proceeding, then all customers are getting the benefit of the integrated system operation of the full range of generation resources from high capital cost/low operating cost generation to low capital cost/high operating cost generation.

Further, in the Stipulation, DNCP, the Public Staff, and CIGFUR I agreed that it is unnecessary at this time for the Company to re-evaluate the issues reviewed in the 1994 Fuel Study.

The Commission notes that cost responsibility based on energy (kWh) allocation has been deemed to produce just and reasonable rates in DNCP's past fuel proceedings. Further, the Commission agrees with DNCP and the other Stipulating Parties, including CIGFUR I, that it is unnecessary at this time to require DNCP to develop an analysis similar to the 1994 Fuel Study. The 1994 Fuel Study analysis preceded Nucor's arrival on to DNCP's system in 2000, Nucor's request in 2001 to transition to a more certain average fuel rate (similar to all other customers), and the subsequent 15 years of history, which informs the Commission's current understanding of DNCP's service to Nucor. In addition, with the weighting of the average of the winter and summer peaks and the ability of high load factor classes in North Carolina to reduce load during peak hours, such customers can reduce, and do reduce, their responsibility for fixed production costs. The Commission concludes based upon the record in this case that it is unreasonable and unnecessary to require DNCP to complete an analysis similar to the 1994 Fuel Study.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 42

The evidence for this finding and these conclusions is found in the Application, the testimony of Company witness Haynes, Public Staff witness Floyd, and Nucor witness Goins, and the Stipulation, and all other evidence of record.

The Application and the testimony and exhibits of Company witness Haynes explain how DNCP proposed to apportion the jurisdictional revenue requirement established using the Company's SWPA jurisdictional and class COSS amongst the customer classes. Witness Haynes' testimony and exhibits assigned the revenue requirement to specific rate schedules and then calculated the percent increase that customers on each rate schedule would experience.

In apportioning the revenue requirement among the customer classes, witness Haynes identified general and class-specific principles that the Company used to equitably distribute the base rate revenue increase, including: (1) all classes should share in the non-fuel base rate revenue increase in a manner that moves each class of customers closer to parity with the North Carolina jurisdictional ROR; (2) for classes outside of a reasonable return index range of 0.90 and 1.10 (Parity Index Range), an effort must be made to more reasonably align the rates customers pay with their responsibility for cost, even if the index achieved after apportionment still remains outside of the Parity Index Range; (3) for purposes of apportioning the increase for the LGS and 6VP classes, the two classes are combined to treat large industrial customers within these classes in the same manner and also to recognize certain non-cost factors that support a lesser increase for large industrial customers with high load factors within these classes; and (4) for purposes of apportioning the increase to the NS Class, the Company balanced the need to equitably address certain legacy economic development rate (EDR) subsidy issues with the unique nature of the Company's electric service arrangement with its largest and most energy-intensive customer, Nucor.

Specific to the non-cost considerations that DNCP took into account in apportioning the revenue increase among the industrial customer classes, witness Haynes testified that he considered the quantity and timing of large industrial manufacturing customers' electric usage in their industrial operations, as well as factory utilization and the economic vitality of the Company's North Carolina service territory, as it relates to these industrial customers.

Witness Haynes presented an extensive history of the Company's agreement with Nucor under which DNCP provides electric service to Nucor, beginning with its approval as an EDR in 1999, and then noted DNCP's concern with the legacy rate of return (ROR) index deficiency in Nucor's contribution towards the Company's cost of service. Witness Haynes explained that the Schedule NS rate design has been beneficial to DNCP's operation of its system, as well as to the North Carolina jurisdiction and to Nucor, and stated that recognition of the partially interruptible nature of service to Nucor's arc furnace under Schedule NS and the Nucor agreement is consistent with North Carolina's policy that a utility may design different rates for different customers based upon differences in conditions of service. Witness Haynes testified that the Company is not opposed to continuing Schedule NS and the Nucor agreement in its current form (subject to Nucor electing otherwise, as discussed below), but that continuing the deficiency in the NS Class' rate of return index, and Nucor's deficient contribution to DNCP's cost of service represents an increasingly inequitable legacy benefit of the initial EDR. Witness Haynes explained that this legacy EDR benefit has extended well past the period originally contemplated in 1999, and significantly longer than the four-year term of EDRs offered to other customers. Accordingly, the Company's Application increased the NS Class ROR index from 0.44 to 0.74, which would move the NS Class two-thirds of the way towards the low end of the Parity Index Range (90% of jurisdictional ROR).

Company witness Haynes also testified that while DNCP developed its allocation and rate design proposals based upon the assumption of continued service, inclusive of the requested base rate increase, under current Schedule NS and the existing Nucor agreement, DNCP also provided notice to Nucor of its intent to terminate the existing Nucor agreement as of December 31, 2016, in order to explore whether Nucor is interested in modifying the current Nucor agreement, or alternatively, receiving service under another available DNCP rate schedule.

Public Staff witness Floyd recommended a more generalized approach to apportioning the revenue increase and designing rates, consistent with the approach and considerations that the Public Staff recommended and the Commission adopted in the Company's 2012 Rate Case. Specifically, witness Floyd recommended that the Commission look at changes to base non-fuel and base fuel revenues together and apply the following principles in spreading the impact to base non-fuel and base fuel revenues: (1) employ a +/- 10% "band of reasonableness" relative to the overall jurisdictional ROR such that, to the extent possible, the class ROR stays within this band of reasonableness following revenue assignment after the rate changes; (2) limit the combined base fuel and base non-fuel revenue increase to no more than two percentage points greater than the overall jurisdictional revenue percentage increase; and (3) minimize subsidization of customer classes by other customer classes.

Nucor witness Goins developed a revenue spread premised on the Commission's adoption of his proposed S/W CP methodology that took into account the following principles: 1) set base rates to bring the ROR for each class within plus or minus 10% (±10% constraint) of the system average ROR; 2) allow no base rate decrease for any class; and 3) limit the base rate increase for any class to no more than 1.5 times the system average increase (1.5x constraint) at a 7.80% ROR. According to Goins' analysis, using S/W CP, the proposed increase would be borne by residential and small general service customers, while other classes would receive no non-fuel base rate increase.

In rebuttal, Company witness Haynes critiqued the proposed revenue apportionment presented by Public Staff witness Floyd. He explained that while certain of witness Floyd's rate design considerations are reasonable from a policy perspective, the Company's significantly more detailed fully-adjusted approach to revenue apportionment and rate design is more reasonable and appropriate. In response to Nucor witness Goins' revenue spread proposal, witness Haynes explained that the rates of return based upon witness Goins' fully adjusted cost of service using the S/W CP method differ dramatically from the Company's results using SWPA, resulting in a significant shift in allocated responsibility for production plant, net operating income and the resulting rate of return. Specifically, he explained that allocated rate base responsibility for the residential class would be 17% higher under witness Goins' proposal and that residential rates must go up by $29.37 million in order to bring the residential class to an equal rate of return with the jurisdiction.

Witness Haynes affirmed the Company's support for its initial proposal to increase non-fuel base revenue for the NS Class two-thirds of the way to the bottom of the rate of return index Parity Index Range (0.90 to 1.10). Witness Haynes testified that DNCP's proposed revenue apportionment and rate design strikes a reasonable balance between Nucor and other customers and does not result in an unreasonable increase or "rate shock" to Nucor, as Nucor's overall rates will decrease on January 1, 2017 as a result of this case.

In the Stipulation, DNCP, the Public Staff, and CIGFUR I agreed that the stipulated overall $25.790 million increase in base non-fuel and decrease in base fuel revenues should be apportioned consistent with the rate design principles presented by Company witness Haynes in his direct and rebuttal testimony, subject to the Stipulating Parties' further agreement that: (1) all classes should share in the non-fuel base rate revenue increase in a manner that moves each class of customers closer to parity with the North Carolina jurisdictional rate of return; (2) the 6VP class Rate of Return Index will be 1.15; and (3) the NS Class Rate of Return Index will be 0.75, which moves the NS Class two-thirds of the way towards the low end of the Parity Index Range of 0.90 and 1.10.

Based on the Stipulation and the evidence in the record, the Commission concludes that for purposes of this proceeding it is appropriate to apportion the proposed base fuel and non-fuel revenue increase approved in this Order using the methodology recommended by DNCP as modified by the Stipulation. The Commission agrees with the Public Staff, Nucor, CIGFUR I, and the Company that revenue should be distributed so that class rates of return are close to the overall jurisdictional rate of return, whenever possible. Further, the effects of rate shock and other economic and inter-class conditions should also be considered. The Commission believes that the principles employed by Company witness Haynes, as modified by the Stipulation, appropriately balance these objectives.

The Commission also recognizes that DNCP provided notice to Nucor on March 1, 2016, of the Company's intent to terminate the existing Nucor agreement as of December 31, 2016, in order to explore with Nucor whether the customer would be interested in modifying the current Nucor agreement, or alternatively, receiving service under another available DNCP rate schedule, consistent with the terms of the Nucor agreement. Based upon the record in this proceeding, no changes have been proposed to the existing terms and conditions of Schedule NS and the Commission accepts DNCP's position as undisputed that the current Schedule NS rate design and partially-interruptible service to Nucor under the Nucor agreement has been beneficial to DNCP's operation of its system, as well as to the North Carolina jurisdiction and to Nucor. Based on the entire record in this proceeding, the Commission finds and concludes that DNCP should offer Nucor service pursuant to the terms and conditions of Schedule NS and the Nucor agreement approved on March 29, 2016 in Docket No. E-22, Sub 517, as modified to reflect the authorized change in non-fuel base revenues.

Basic Customer Charge

In his testimony, Public Staff witness Floyd discussed the Company's proposed changes to the basic customer charge. He explained that the unit cost data in Item 45e is an approximation of the cost associated with each unit of service for a given utility function and provides an indicative benchmark to use when designing individual rate elements of various rate schedules. Witness Floyd compared the unit cost data in this proceeding to similar data from the 2012 Rate Case and found that those costs designated as "customer" unit costs have decreased since the 2012 Rate Case. This review suggested to him that the basic customer charges currently approved for DNCP rate schedules are greater than the "customer" designated unit costs found in Item 45e. Witness Floyd therefore recommended that none of DNCP's basic customer charges be increased.

In his rebuttal, Company witness Haynes accepted witness Floyd's recommendation with the understanding that any needed revenue apportionment to the rate schedules would be apportioned to the other charges in the rate schedules. The Stipulation provides that in developing rates based upon the class apportionment agreed to in the Stipulation, the Company agrees to recover 100% of the stipulated revenue increase through the energy and demand components of rates and not to increase the basic customer charge component of rates. The Commission finds this provision of the Stipulation to be reasonable and appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 43

The evidence for this finding of fact and these conclusions is found in the Application, the testimony of DNCP witness Haynes and Public Staff witness Floyd and the Stipulation.

The Company's Application proposed new Large General Service Schedule 6L, which is designed as an additional rate option for DNCP's large industrial customers in addition to existing rate schedules 6C, 6P, 6VP, and 10.

Company witness Haynes explained that the Company developed Schedule 6L in response to recent concerns expressed by DNCP industrial customers that the current industrial Schedule 6P rate is less preferable compared to rate options available in other utilities' service territories. He presented an example showing how the design of rates can impact economic competitiveness and factory utilization and potentially may cause a hypothetical industrial customer in DNCP's North Carolina service territory to consider moving production to a facility located elsewhere in order to lower its electricity bill and thus lower its cost of production. Witness Haynes described the new Schedule 6L as a potentially more advantageous option than existing Schedule 6P for "high load factor" customers that place demands on the Company's system during most if not all hours of the day for seven days per week, and generally maintain annual load factors of approximately 80% and higher. Witness Haynes testified that the new optional Schedule 6L would be applicable to large industrial customers that have achieved a demand of at least 3,000 kW in the three billing months during the most recent 12-month period.

Witness Haynes explained that Schedule 6L is designed to recover more costs through demand charges and less through energy charges when compared to existing Rate Schedule 6P. Witness Haynes also explained that the Company has amended the Company's Rider EDR tariff to include Rate Schedule 6L as an eligible rate schedule. The Company proposed to continue to offer Rate Schedule 6P, as this schedule is appropriate for industrial and commercial customers that do not have an extensive need for electricity around the clock.

Public Staff witness Floyd recommended that the Commission approve proposed Schedule 6L, subject to one change in the tariff language to eliminate the NAICS "Manufacturing" classification as part of the qualification for this rate schedule. Witness Haynes testified in rebuttal that the Company agrees with witness Floyd's proposed change and that the specific NAICS "Manufacturing" classification eligibility limitation had been eliminated in the revised Schedule 6L included as Company Rebuttal Exhibit PBH-1, Schedule 12.

During the hearing, witness Haynes further explained that over the last 10 to 12 years, the Company has developed new rates and structures to address concerns of industrial customers. He testified that about 10 years ago, the Company developed a new Schedule 6VP rate to recognize that some large industrial high usage customers had the ability to curtail in certain hours given a price signal. He explained that proposed Schedule 6L is designed in response to the needs of certain high load factor customers and would recover more costs in the demand component. Under Schedule 6L, the average cost to a high load factor customer under Schedule 6L will be approximately 5.7 cents/kWh. Witness Haynes also testified that DNCP's industrial rates are competitive in North Carolina and significantly lower than industrial customer rates across the EEI South Atlantic region.

The Commission finds and concludes based upon all evidence in the record that Rate Schedule 6L, as presented in Company Rebuttal Exhibit PBH-1, Schedule 12 is reasonable and nondiscriminatory, and should be approved. No party objected to the Schedule 6L design, as amended by DNCP to address the Public Staff's eligibility recommendation. Further, no party disputed witness Haynes testimony during the hearing that certain of the Company's high load factor customers could benefit from the Schedule 6L design.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 44

The evidence supporting this finding of fact and these conclusions is contained in the Application, the testimony of Nucor witness Thomas, the direct and rebuttal testimony of Company witness Haynes, the Stipulation, and the entire record in this proceeding.

As described in the Application and the testimony of Company witness Haynes, DNCP develops its COSS for purposes of allocating and assigning the cost of utility service to the North Carolina jurisdiction and between the North Carolina customer classes. Since DNCP's 2012 Rate Case, the Company has evolved its cost of service model from a basic Microsoft Excel-based model to the Utilities International (UI) Model, a subscription software-supported model developed by UI. The UI Model provides the Company a staged database platform through which business units can directly input cost and other source information into the UI Model. The Company's Cost Allocation group then maintains the UI Model and uses to it perform all cost of service-related regulatory functions, including developing the COSS for North Carolina rate cases. During this proceeding, Nucor as well as other parties requested that DNCP run alternative COSS using alternative allocation methodologies to DNCP's SWPA method.

Nucor witness Thomas developed and supported a fully adjusted S/W CP COSS analysis. Witness Thomas explained that he relied upon information provided in discovery by the Company to develop Nucor's fully-adjusted S/W CP COSS analysis, but commented that the Company's transition to the UI Model has caused difficulty for Nucor and parties other than DNCP to run alternative cost of service (COS) analyses. Witness Thomas testified that DNCP held conference calls with Nucor to explain the UI Model and also made the UI Model available upon reasonable notice at the Company's offices in Richmond for in-person inspection. Witness Thomas testified that DNCP's historic use of spreadsheet-based COS models was more usable by Nucor and other parties who could run various scenarios to evaluate and test the impacts of potential changes in allocator methodologies, allocator selections, changes in recommended ratemaking adjustments, changes in revenue requirements, and other scenarios. He also explained that the UI Model uses its own programming language, and that it could take considerable time for someone unfamiliar with the software to learn how to use the software and subsequently audit the software to validate its functionality. Witness Thomas concluded that although Nucor was able to develop a fully-adjusted S/W CP COS model run, his opinion was that the UI Model presents an undue burden on parties in this proceeding and severely limits their capabilities relative to the spreadsheet-based COS models used by DNCP in prior proceedings.

In rebuttal, Company witness Haynes responded that the Company has worked diligently in this case to be supportive of the regulatory process by performing original work to run COSS requested through data requests and motions by CIGFUR I and Nucor, respectively, and also offered to make the UI Model available for inspection at the Company's office in Richmond. Witness Haynes testified that the Company plans to work with Utilities International to determine whether Utilities International can produce an application that would enable an intervenor or the Public Staff to perform certain UI Model functionalities in spreadsheet-based Excel, generally including manipulating allocation factors to prepare their own COSS in future rate case proceedings.

In the Stipulation, DNCP, the Public Staff, and CIGFUR I agreed that the Company will work with Utilities International to determine whether it can produce an application that would enable an intervenor or the Public Staff to perform certain UI Model functionalities in Excel, generally including manipulating allocation factors to prepare their own cost of service studies in future rate case proceedings.

The Commission finds and concludes that the Company has worked in good faith and made reasonable efforts in this case to provide Nucor and other parties with COS-related information through the normal discovery process. The Commission finds that DNCP's commitment in the Stipulation to work with Utilities International regarding assessing reasonable additional COS functionalities that can be produced in an Excel spreadsheet-based format should be completed prior to DNCP filing its next general rate case.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 45

The evidence supporting this finding of fact and these conclusions is contained in the testimony and exhibits of Company witness Haynes and Public Staff witness Floyd and the Stipulation.

Public Staff witness Floyd testified that DNCP does not currently offer customers any lighting services or fixtures that use LED (light emitting diode) technologies. Schedule 26, DNCP's outdoor area and street lighting tariff, only offers mercury vapor and high pressure sodium fixtures. In response to a Public Staff data request, DNCP indicated that it was currently investigating new LED lighting services in conjunction with contract negotiations between the Company's Virginia affiliate and several Virginia municipalities. The Company's response suggested that once these negotiations were completed, and the Company had a better understanding of the LED lighting services that would be covered by those contracts, DNCP could bring new LED lighting services to the Commission for approval. Based on this information, witness Floyd recommended that the Commission require DNCP to either file a request for approval of new LED lighting services and fixtures within one year following the Commission's order in this proceeding or for DNCP to incorporate a new LED lighting services and fixtures rate option in its next general rate case, whichever comes first.

In his rebuttal, Company witness Haynes agreed with witness Floyd's recommendation. The Stipulation provides that the Company agrees to develop and file for Commission approval a new LED schedule for North Carolina jurisdictional customers within one year of the Commission's final order in this proceeding. The Commission finds and concludes that this provision of the Stipulation is reasonable and appropriate and should be adopted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 46

The evidence for this finding of fact and these conclusions is found in the cross-examination of Company witness Haynes by CUCA, and the entire record before the Commission in this proceeding.

During cross-examination by CUCA, Company witness Haynes described Real Time Pricing (RTP) rates. Witness Haynes indicated that a RTP rate is no longer offered to customers in DNCP's service territory in North Carolina. He further stated that if the

Company deemed a RTP rate to be something it wanted to offer its customers, it could bring that forward.

In its post-hearing Brief, CUCA submitted that RTP rates tend to have a significant beneficial impact on high load factor customers. CUCA urged the Commission to require DNCP to propose a pilot RTP rate by July 1, 2017, and to present its RTP proposal for a ruling by the Commission by the end of 2017.

The Commission is of the opinion that an RTP rate, if offered, could provide high load factor customers significant benefits. Therefore, the Commission finds and concludes that it is reasonable to require the Company to propose a pilot or experimental RTP rate offering no later than July 1, 2017.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 47

The evidence supporting this finding of fact and these conclusions is found in the testimony and exhibits of Company witness Haynes, the cross-examination by NCSEA and Commissioner Patterson, and the agreement between DNCP and NCSEA.

Company witness Haynes sponsored Company Exhibit PBH-1, which shows DNCP currently has a combined total of 307 residential customers participating in their Time of Use (TOU) rate tariffs (258 customers for Schedule 1P and 49 customers for Schedule 1T). This represents only 0.3% of DNCP's 102,058 residential customers. This is a decrease from 2007, when 366, or 0.4% of DNCP's residential customers received service under a TOU rate tariff.

In its post-hearing Brief, NCSEA requested that the Commission require DNCP to take three actions with regard to TOU rates: (1) offer a rate comparison and potential savings calculation to residential customers who receive a smart meter; (2) in its next general rate case, include a cost of service study that investigates the impacts of making TOU rates the default rate for new residential customers; and (3) file with the Commission the results of certain TOU pilot projects approved by the Virginia SCC.

On December 13, 2016, DNCP and NCSEA filed a letter with the Commission describing the agreement reached by them on the issues raised by NCSEA regarding TOU rate offerings by DNCP. In summary, the agreement provides that DNCP will file with the Commission and serve on all parties to this docket the final annual report to the Virginia SCC regarding DNCP's Dynamic Pricing Pilot Program and Electric Vehicle Pilot Program in the Company's Virginia jurisdiction.[23] Further, DNCP states that it objects to NCSEA's recommendation that the Company perform a rate comparison for every customer who has received a smart meter and is currently served on a non-TOU residential rate, but that the

[23] Virginia Electric and Power Company's Proposed Pilot Program on Dynamic Rates, Virginia SCC Case No. PUE-2010-00135; Application of Virginia Electric and Power Company for Approval to Establish an Electric Vehicle Pilot Program pursuant to § 56-234 of the Code of Virginia, Virginia SCC Case No. PUE-2011-00014.

Company will agree to investigate improving the rate comparison process for residential customers. This investigation will include studying the feasibility of a web-based tool designed to educate customers about TOU rates and providing tools for residential customers to perform their own rate comparison. The Company agrees to discuss the findings of this investigation with NCSEA by the end of 2017.

In addition, the Company states that it objects to NCSEA's recommendation that the Company default residential customers to a TOU rate. The Company also objects to NCSEA's request that the Company develop an alternative cost of service study methodology for inclusion in a future general rate case application, as such an undertaking would be unduly burdensome. However, DNCP agrees to investigate a way to study the impacts of defaulting new residential customers onto TOU rates in a cost of service study and report to the Public Staff and NCSEA the findings of such a study by October 1, 2017. The Company will conduct this investigation using readily available information prepared for the Company's filing in Docket E-22 Sub 532. Moreover, DNCP will provide to NCSEA consolidated hourly profile information for rate schedules 1P and, separately, 1T.

Finally, the agreement states that NCSEA withdraws the recommendations in its post-hearing Brief in consideration of the Company's commitments as set forth above.

The Commission is sensitive to the impact that any residential rate increase has on utility customers in North Carolina, particularly low-income customers. The Commission wants to ensure that DNCP's customers are fully aware of existing rate tariffs that could help them reduce monthly bills. The Company's response (in part) to the NCSEA Data Request Number 2, Question Number 6, states "Customers who received smart meters were not provided with information about DNCP's TOU rate schedules." The Commission finds and concludes that DNCP should be required to provide a written summary of its TOU rates, and its RTP rates, when developed, to each residential customer presently being served and to be served in the future by a smart meter. In addition, the Commission encourages the Company to investigate opportunities to better educate its customers on the benefits of TOU rates.[24]

In addition, the Commission finds and concludes that the terms of the agreement between DNCP and NCSEA are reasonable, are in the public interest, and should be approved

[24] Report of the North Carolina Utilities Commission Regarding an Analysis of Rate Structures, Policies, and Measures to Promote Renewable Energy Generation and Demand Reduction in North Carolina, Docket No. E-100, Sub 116 (September 2, 2008).

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 48

The evidence supporting this finding of fact and these conclusions is contained in the Application, the testimony and exhibits of Company witness Haynes and Public Staff witness Floyd and the Stipulation.

Item 39 of the Company's Form E-1 filed with the Application and the Company's supplemental direct testimony showed the changes the Company proposed to make to each section of the Terms and Conditions, Rider D-Tax Effect Recovery, Fuel Rider A, and Rider EDR. No party testified in opposition to the adoption of the proposed changes to the Terms and Conditions, and the Stipulation provides that DNCP's Terms and Conditions should be revised as set forth in Item 39 of the Company's Form E-1 filed with its supplemental direct testimony. The Commission finds and concludes that this provision of the Stipulation is reasonable and appropriate and should be adopted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 49

The evidence supporting this finding of fact and these conclusions is contained in the verified Application and DNCP's Form E-1, the testimony and exhibits of Company witness Curtis and Public Staff witness McLawhorn, and the entire record in this proceeding.

Company witness Curtis provided testimony regarding DNCP's performance with regard to customer service. He testified that the Company's generating fleet has demonstrated excellent performance results. He also stated that DNCP continues to provide excellent customer service, and that the Company has improved its North Carolina System Average Interruption Duration Index (SAIDI), excluding major storms performance, by over 20% since 2007, and maintained consistent performance below 120 minutes since 2012. He noted that because of DNCP's previous infrastructure investments, the Outer Banks area continues to be one of the best performing areas across DNCP's entire service territory.

Witness Curtis also testified that the Company continues to achieve excellence in customer service by offering innovative solutions in response to customer expectations, including leveraging technology to perform quick, seamless customer transactions. He noted that DNCP customers completed more than 13 million online transactions during 2015, and that usage of electronic transactions has increased by 61% since 2012. He described the Company's promotion of social media interactions with customers, including its implementation in 2014 of an interactive map that allows customers to view current outages and see details of current outages, such as status and estimated restoration time. Witness Curtis also testified about recognition for outstanding performance that the Company's parent, Dominion Resources, Inc., had received during the past several years.

Public Staff witness McLawhorn testified that the Public Staff had reviewed service-related complaints received by the Public Staff's Consumer Services Division, the

Company's call center operation reports filed with the Commission, SAIDI and SAIFI statistics, the Company's report on new residential service installations, and complaints directly received by DNCP related to vegetation management. Based on the low number of service-related complaints and the relative level of its service metrics, witness McLawhorn found the overall quality of electric service provided by DNCP to retail customers to be adequate.

Based on the testimony of Company witness Curtis and Public Staff witness McLawhorn, the Commission finds and concludes that the overall quality of electric service provided by DNCP is good.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 50

The evidence supporting this finding of fact and these conclusions is contained in the Application, the direct, supplemental, and rebuttal testimony and exhibits of DNCP witnesses Hupp and Bailey, the Company's July 8, 2016 Supplemental Filing, the testimony of Public Staff witness McLawhorn, the Stipulation, and the hearing testimony. In addition the Commission relies on its April 19, 2005 Order Approving Transfer Subject to Conditions in Docket No. E-22, Sub 418 (the PJM Order), and the post-hearing exhibit filed by DNCP.

In the Application, the Company requested relief going forward from the regulatory conditions imposed in the PJM Order. The over-arching goal of the conditions in the 2005 PJM Order was stated as follows: "That Dominion's North Carolina retail ratepayers shall be held harmless from all direct and indirect effects and costs, either related to operations, quality of service, reliability, or rates, arising from its integration with PJM ...."

PJM Order Condition (1)a states that:

> Dominion's North Carolina retail customers shall continue to be entitled to, and receive, cost-based rates for generation, transmission, and distribution (including any ancillary services) determined pursuant to North Carolina law using the same ratemaking methodology as that employed by this Commission as of the time of Dominion's joining PJM notwithstanding Dominion's integration into PJM or decision to participate in any capacity or energy market administrated by PJM; that is, under no circumstances(s) or event(s) shall the costs of generation and transmission, among other things, included in Dominion's N.C. retail rates be greater than the lesser of (1) such costs determined on the basis of historical, embedded costs, calculated consistent with the Commission's currently existing rate base, rate-of-return ratemaking practices and procedures, or (2) the marginal costs of generation and transmission supplied into or purchased from PJM;

PJM Order Condition (1)b states that:

> Dominion shall continue to serve its native load customers in North Carolina with the lowest-cost power it can generate or purchase from other sources

in order to meet its native load requirements before making power available for off-system sales;

PJM Order Condition (1)c states that:

Dominion shall take all reasonable and prudent actions necessary to continue to provide its NC retail customers with the same (or higher) superior level of bundled electric service as that provided prior to Dominion's integration with PJM, including, for example, reliable generation, transmission, and distribution service; and responsive customer service;

PJM Order Condition (1)d states that:

Dominion shall not include in base rates: (a) PJM administrative fees or any replacement mechanism for such fees approved by FERC[25]; (b) PJM transmission congestion costs or revenues from PJM for financial transmission rights (FTRs) or auction revenue rights (ARRs) or any replacement mechanism for such cost and revenues approved by the FERC; (c) any increase in transmission service charges to the Company resulting solely and directly from a change in rate structure from license plate rates to another rate structure for recovering the embedded costs of transmission facilities used to provide Network Integration Transmission Service; (d) any increase in transmission charges resulting from charges associated with regional transmission expansion costs that are chargeable under the PJM Tariff to the Dominion zone, and which are not included in the Company's transmission revenue requirement; or (e) any increase in transmission costs to the Company or any revenues resulting from the FERC's orders in Docket Nos. ER04-829 and ER05-6 et al. imposing the Seam Elimination Cost Adjustments (SECAs);

PJM Order Condition (1)e states that:

Dominion shall allocate sufficient FTRs, ARRs, or other revenues toward its fuel costs to offset any congestion charges or other fuel-related costs resulting from Dominion joining PJM and sought to be recovered from Dominion's North Carolina retail ratepayers through the operation of G.S. 62-133.2;

PJM Order Condition (1)f states that:

Neither PJM, Dominion nor any affiliate shall assert in any proceeding in any forum that federal law, including, but not limited to, the Public Utility Holding Company Act of 1935 (PUHCA) or the Federal Power Act (FPA), preempts the Commission from exercising such authority as it may otherwise have (or would have were Dominion not a member of PJM) under

[25] FERC is the Federal Energy Regulatory Commission.

North Carolina law to set the rates, terms and conditions of retail electric service to Dominion's North Carolina retail ratepayers and that Dominion shall bear the full risks of any such preemption;

PJM Order Condition (2) states that:

> Dominion and PJM shall, consistent with, and to the extent not altered by, the above regulatory conditions and this Order, comply with the terms of the Joint Offer of Settlement [JOS] filed December 16, 2004.

The JOS had two signatories: PJM and Dominion. Some of its provisions ended as of December 31, 2014, but others did not. Some of the provisions were reiterated by the Commission in the PJM Order and were put in place "until further Order of the Commission." In its July 8, 2016 Supplemental Filing, Dominion reiterated that it is seeking relief from compliance with the JOS.

PJM Order Condition (3) states that:

> Dominion and PJM shall, consistent with the above additional regulatory conditions, comply with the terms of the Settlement Agreement with Progress filed December 16, 2004. Dominion and PJM shall, with regard to all of the signatories thereof, honor , and discharge Dominion's obligations pursuant to, the various VACAR[26] and other regional agreements referenced in the Settlement Agreement, including, but not limited to the VACAR Reserve Sharing Agreement, as Dominion would have been so obligated to do prior to Dominion's integration with PJM. In fulfilling this condition, Dominion and PJM shall continue to follow the practices and operating procedures around these agreements that have been customarily observed by the participants but do not necessarily exist in written form.

The "Progress Settlement Agreement" among DNCP, PJM and Progress Energy Carolinas, Inc. (now Duke Energy Progress) contained six very detailed provisions intended to ensure that commitments and practices that DNCP had made or instituted in order to assure reliability in the VACAR region during emergencies would survive, with specific tasks being agreed to by PJM.

PJM Order Condition (4) states that Dominion would continue to comply with all regulatory conditions and codes of conduct previously imposed by the Commission. The PJM Order further stated that "the conditions imposed by the Commission shall remain in effect for a period of not less than ten (10) years from the date of Dominion's integration into PJM and continuing thereafter indefinitely and until further Order of the Commission."

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[26] VACAR is a sub-region of the SERC Reliability Corporation (SERC), and covers the states of Virginia, North Carolina and South Carolina. In the Southeast, SERC implements and enforces the reliability standards that are developed by NERC and approved by FERC.

In his direct testimony, DNCP witness Hupp noted that the Commission imposed the PJM conditions for a period of not less than 10 years and indefinitely until further Commission order, and that more than 10 years have passed since DNCP integrated with PJM. Witness Hupp testified that to the best of his knowledge, since integration into PJM, DNCP has complied with all of the PJM Order conditions and has held customers harmless via the operational and financial benefits provided by DNCP's membership in PJM. Witness Hupp described the operational benefits as more reliable and efficient operations, improved outage and reserve planning, and participation in the PJM stakeholder process.

Witness Hupp also testified that in Docket No. E-22, Sub 428, the Commission ordered DNCP to perform, beginning with its next fuel case, a study of the fuel costs that would have been incurred had DNCP not joined PJM (the PJM Integration Study). Witness Hupp stated that in each of the ten PJM Integration Studies conducted from 2006 through 2015, DNCP demonstrated significant savings to customers as a result of DNCP's PJM membership. Particularly since 2009 when the Company began using the PJM Integration Study in its current form, witness Hupp testified that the studies demonstrate substantial financial savings that outweigh the costs, including administrative costs, associated with DNCP's integration into PJM.[27]

Witness Hupp testified that based on the consistently demonstrated benefits of DNCP's PJM integration since 2005, the Company should be relieved from further compliance with the PJM conditions. He explained that the Company's integration into PJM is now complete, and concerns about new and unknown aspects of joining a regional transmission organization no longer apply. Witness Hupp noted that in the Company's 2014 fuel factor proceeding the Commission recognized that due to the passage of time since the integration with PJM, one or more of the PJM conditions could be ripe for review.

Witness Hupp testified that several of the PJM conditions prohibit the Company from recovering through rates certain costs associated with PJM participation. These costs include congestion and other fuel-related costs which Condition 1(e) required DNCP to offset with Financial Transmission Rights (FTRs), Auction Revenue Rights (ARRs), and other revenues. Witness Hupp noted that in the Company's 2014 fuel case, due to this condition, the Commission disallowed recovery of $1.5 million of congestion costs that the Company believed were prudently incurred. Condition 1(d) similarly prohibits DNCP from recovering administrative costs associated with PJM membership. Witness Hupp clarified that DNCP is not asking to pass such costs on to customers without a prudence review. Instead, the Company seeks the opportunity to recover these prudently incurred costs.

In its July 8, 2016 Supplemental Filing the Company provided more specific representations regarding its ongoing commitments for its continued retail electric service in North Carolina, notwithstanding its request for relief from the PJM Order conditions.

[27] DNCP is not currently required to perform the PJM Integration Study pursuant to the Commission's final order in the Company's 2015 fuel clause adjustment proceeding, Docket No. E-22, Sub 526.

The Company also presented a detailed cost-benefit analysis of the impact of the PJM integration on customers, supported by the supplemental direct testimonies of witnesses Hupp and Bailey.

DNCP clarified in the Supplemental Filing that, while the Company is seeking relief from all of the PJM Order conditions, certain obligations to which it is subject as a North Carolina regulated electric utility exist separate and apart from the PJM conditions and will continue to apply to the Company even if the Commission grants the Company's request for relief. Furthermore, the Company is subject to some regulatory conditions that were imposed by the Commission before DNCP joined PJM, and DNCP stated that it would remain subject to all such conditions.[28] The Company clarified that it would continue to comply with the following obligations:

> (1) DNCP's North Carolina retail customers will continue to be entitled to, and receive, cost-based rates for generation, transmission, and distribution (including any ancillary services) determined pursuant to North Carolina law notwithstanding DNCP's integration into PJM or decision to participate in any capacity or energy market administered by PJM.
>
> (2) DNCP will continue to serve its native load customers in North Carolina with the lowest-cost power it can generate or purchase from other sources in order to meet its native load requirements before making power available for off-system sales.
>
> (3) DNCP will continue to take all reasonable and prudent actions necessary to continue to provide its North Carolina retail customers with superior bundled retail electric service and customer service.
>
> (4) Neither DNCP nor any of its affiliates will assert in any proceeding in any forum that federal law, including but not limited to the Public Utility Holding Company Act of 1935 (PUHCA) or the Federal Power Act (FPA), preempts the Commission from exercising such authority as it may otherwise have (or would have were DNCP not a member of PJM) under North Carolina law to set the rates, terms, and conditions of retail electric service to DNCP's retail ratepayers, and DNCP shall bear the full risks of any such preemption.
>
> (5) DNCP will continue to comply with all regulatory conditions and codes of conduct previously imposed by the Commission.

[28] Those previously imposed regulatory conditions include Regulatory Conditions 30-42 to the Commission's October 18, 1999 Order Approving Code of Conduct and Amending Conditions of Merger issued in Docket No. E-22, Sub 380, which prohibited the Company from asserting federal preemption of the Commission's authority in any forum.

The Company also provided information in the Supplemental Filing regarding how the other conditions contained in the PJM Order either are moot or are otherwise covered by other agreements.

With regard to Condition (1) of the PJM Order, DNCP clarified that it is requesting relief from the portion of this Condition that requires that the costs of generation and transmission, among other things, included in DNCP's North Carolina retail rates be no greater than the lesser of such costs determined on the basis of historical, embedded costs, calculated consistent with the Commission's currently existing rate base, rate-of-return ratemaking practices and procedures, or the marginal costs of generation and transmission supplied into or purchased from PJM. The Company reiterated that it would continue to set rates for service based on its cost of service.

With regard to Condition (2) of the PJM Order, which requires DNCP and PJM to comply with the terms of the Joint Offer of Settlement, DNCP clarified that it is seeking relief from this condition. The Company stated that Paragraphs (1) through (6) of the Joint Offer of Settlement either were subsumed within broader obligations imposed by the conditions contained in the PJM Order or were subject to sunset dates that have since passed.

The Company also explained that Paragraphs (7)(a) through (7)(c) of the Joint Offer of Settlement outline curtailment protocols that have been superseded by current PJM and North American Electric Reliability Corporation (NERC) requirements as provided for in the PJM tariff and NERC reliability standards.

With regard to Paragraph (7)(d) of the Joint Offer of Settlement, which states that "nothing in this approval of this application shall alter the Commission's authority over the application of curtailment practices to Company's retail customers," DNCP stated that any current authority held by the Commission regarding the application of curtailment practices would remain in effect even if the Commission grants the Company's request for relief from these conditions.

DNCP explained that the obligations imposed by Paragraph (8) of the Joint Offer of Settlement, which required a stakeholder process related to locational marginal pricing and settlements, have been fulfilled by PJM's actions to implement Residual Metered Load market rules, which took effect June 1, 2015.

DNCP stated that Paragraphs (9) through (11) of the Joint Offer of Settlement address obligations to which it is already subject as a North Carolina regulated electric utility and that will continue to apply to the Company even if the Commission grants the Company's request for relief from the PJM Order conditions. These obligations include the need to seek permission to build electric generation and transmission facilities in North Carolina, the requirement to comply with the Commission's integrated resource planning requirements, the requirement to promptly address reliability and service quality issues, and the requirement to follow the laws, rules and policies of the Commission for the provision of retail electric service. The Company clarified that it is not seeking authorization to cease compliance with any of these obligations.

DNCP stated that the Commission's jurisdiction over any subsequent transfer of the Company's North Carolina transmission facilities exists independent of Paragraph (12), making that provision unnecessary.

Paragraph (13) provided for the confidentiality of the discussions that resulted in the Joint Offer of Settlement. DNCP stated that due to the passage of time and the application of other agreements, this provision is no longer relevant. Even so, DNCP will continue to treat as confidential any information provided as such.

Paragraph (14) asserted that changes to the Joint Offer of Settlement required the Company's agreement. DNCP stated that, to the extent this requirement is deemed to apply, the Company was submitting a written signed request for relief from the Joint Offer of Settlement.

Paragraph (15) addressed the possibility that the Commission might not accept the Joint Offer of Settlement. DNCP stated that because the Commission had issued its Notice of Decision on March 30, 2005, in Docket No. E-22, Sub 418, Paragraph (15) is moot.

With regard to Condition (3) of the PJM Order, which pertains to the Settlement Agreement between DNCP and DEP that was filed on December 16, 2004, in Docket No. E-22, Sub 418 (Progress Settlement), DNCP clarified that it is seeking relief from this condition. DNCP represented that it had conferred with counsel for DEP, and that DEP and DNCP agreed that the obligations and commitments contained in the VACAR Reserve Sharing Agreement and other regional agreements referenced in the Progress Settlement are being met pursuant to the current, updated versions of those agreements, as well as other agreements entered into subsequent to the Company's PJM integration, including the Joint Operating Agreement between PJM and DEP most recently filed with FERC in Docket No. ER15-29-000. DEP and DNCP therefore agreed that a Commission Order relieving DNCP of the obligation to comply with the terms of the Progress Settlement would not adversely impact the legal effectiveness of the terms and conditions applicable to DNCP, PJM, and DEP under these agreements.

In his supplemental testimony, witness Hupp presented the results of the Company's detailed analysis of the full costs and benefits of PJM integration over the period of 2006-2015. He explained that the analysis compares actual cost and benefit data from the 10-year period during which DNCP has been a PJM member to a theoretical environment in which DNCP did not join PJM and instead continued to operate as a separate control area. He stated that the Company analyzed several categories of cost and benefit data from 2006 through 2015, including market energy, FTRs, ancillary services, administrative costs, market capacity, and transmission costs. Witness Hupp provided detailed descriptions of how the Company derived the data for each category, and testified that the results of the analysis for all of the categories except administrative costs showed there was a substantial economic benefit to the Company's North Carolina retail customers from its integration into PJM. He noted that the Company did not attempt to speculate as to the comparable administrative costs that the Company would have incurred as a separate control area, and that the administrative costs associated with PJM membership were significantly more than offset by the economic benefits realized in each of the other analyzed categories.

In his supplemental testimony, DNCP witness Bailey testified in support of witness Hupp's discussion of the transmission-related costs and benefits associated with DNCP's PJM participation over the 2006-2015 period. Witness Bailey stated that the cost-benefit analysis assumes that the same transmission projects would be developed whether or not the Company was a member of PJM or a separate control area. In support of this assumption, witness Bailey explained that projects developed pursuant to the PJM Regional Transmission Expansion Plan (RTEP) process include "baseline," "supplemental," and "network" projects. He stated that the RTEP process identifies baseline projects for development that are needed to comply with, for example, mandatory NERC reliability standards and, as such, those projects would likely have been developed whether or not the Company was a PJM member. He also stated that the vast majority of supplemental projects, which DNCP develops in response to specific customer needs are based on the need to support load growth or additions that also would be present whether or not DNCP was in PJM. Finally, witness Bailey testified that since network projects are developed in response to specific generation, merchant transmission, or long-term firm transmission service requests and are paid for by the requesting interconnection entity, those projects were not reflected in the cost/benefit analysis.

In his direct testimony, Public Staff witness McLawhorn summarized the PJM Order conditions and the Company's direct and supplemental filings. He stated that based on the Public Staff's review of DNCP's cost benefit analysis and its consultation with an outside consultant, Christensen Associates Energy Consulting, the Public Staff believes that DNCP's study methodology was generally reasonable and that the available data are verifiable. Witness McLawhorn noted that while the Public Staff believes that DNCP's quantification of the net benefits associated with its PJM membership may be overstated, the Public Staff agrees that there has been a net economic benefit to DNCP ratepayers from 2006-2015 as a result of the integration. He also stated that, based on the most current projections of natural gas prices, capacity prices, and other PJM-related costs, the Public Staff expects the net benefits of DNCP's membership in PJM to continue, driven mainly by fuel cost savings. Witness McLawhorn concluded that, based on its review of the cost/benefit analysis and the clarifications made in the Supplemental Filing, the Public Staff believes that the benefits of DNCP's integration into PJM exceed the costs, and that these benefits can be expected to continue under current forecasts, even with inclusion of the costs previously excluded by Conditions 1(d) and (e). He noted further that, as to Conditions 1(a)-(c), (f), 2, 3 and 4, the Public Staff believes that the clarifications made by the Company in the Supplemental Filing are appropriate and sufficient to support relief from those conditions, with the exception of the filing requirements in Paragraphs 5 and 6 of the JOS. These two paragraphs require the filing of information related to congestion costs and transmission constraints, revenues associated with FTRs and ARRs, a summary of DNCP's monthly capacity and energy transactions with the PJM markets, and locational marginal pricing information.

Witness McLawhorn recommended that, to the extent that DNCP does not already file the information required by these Paragraphs in its annual fuel rider application, DNCP should be required to file that information in the same or substantially similar detail as the filing made by the Company on August 31, 2016, with its annual fuel proceeding. Otherwise, he stated that the Public Staff does not oppose the Company's request for relief from the PJM conditions as clarified by DNCP in the Supplemental Filing. Witness McLawhorn recommended that the Commission's order granting the Company's request for relief from these conditions specifically address the subject matter of Conditions 1(a)-(c), (f), 2, 3, and 4 and incorporate the clarifications made by the Company in its Supplemental Filing. Finally, witness McLawhorn testified that the Public Staff believes that the Commission will be able to protect North Carolina ratepayers should DNCP's participation in PJM prove not to be beneficial in the future. He stated that the Commission has full authority to ensure that DNCP complies with the representations and commitments made in the Supplemental Filing with respect to obligations that exist separate and apart from the PJM conditions, including regulatory conditions previously imposed by the Commission. With regard to the additional PJM costs that DNCP may seek to recover from ratepayers upon being relieved of the PJM conditions, that is, costs excluded from rates under Conditions 1(d) and (e), such costs would be recoverable only when they are shown to have been reasonable and prudently incurred.

In his rebuttal testimony, witness Hupp testified that the Company does not oppose witness McLawhorn's recommendation that the Company continue to file the information required by Paragraph 5 of the JOS in conjunction with its annual fuel cases. He also stated the Company's understanding that the independent market monitor for PJM will continue to file the information required by Paragraph 6 of the JOS. [29]

Section XIV of the Stipulation provides that the Company is relieved from further compliance with the PJM Order conditions, subject to: (1) the Company's clarifications regarding its ongoing commitments as contained in its July 8, 2016 Supplemental Filing in this docket; (2) the Company's continuing to file with its annual fuel clause adjustment filing the information required by Paragraph 5 of the JOS; and (3) the IMM for PJM continuing to annually file the information required by Paragraph 6 of the JOS. Section XIV also provides that the Company will comply with the representations and commitments made in the Supplemental Filing with respect to obligations that exist separate and apart from the PJM Conditions.

[29] The Commission notes that on November 16, 2016, counsel for Monitoring Analytics, LLC (PJM's independent market monitor) filed a letter in this docket stating that "should the Commission accept the Stipulation, Monitoring Analytics, LLC, acting as the [IMM] for PJM will continue to annually file ... the information specified in Paragraph 6 of the Joint Offer of Settlement ... filed in ... 2004."

No other party submitted evidence regarding the Company's request for relief from the PJM conditions.

At the hearing, witness Hupp testified in response to Commission questions that the Company would not object to the Commission directing DNCP to continue to comply with the obligations it agreed to continue to meet in the Supplemental Filing notwithstanding the Company's request for relief from the conditions related to those obligations. On redirect, witness Hupp agreed that the Company took the approach of requesting relief from all the conditions while committing to continue compliance with its independent and ongoing obligations as a North Carolina retail electric utility as that would allow for a "clean slate" going forward. Witness Hupp noted that the forward-looking evaluation of costs and benefits that the Public Staff conducted indicated that the benefits and savings of PJM integration would continue. He stated on redirect that it is no longer valid to compare the circumstances before the Company joined PJM to those after integration, given the length of time that DNCP has been a PJM member and the benefits it has shown from integration. He also confirmed that regardless of whether it is a PJM member, the Company always seeks to provide service at least cost and to economically dispatch its fleet.

Witness Hupp confirmed in response to Commission questioning that certain decisions that the Company makes with regard to operating within PJM, such as whether to bid into the markets or buy market energy, would be subject to prudence review. He agreed that, with regard to other costs that PJM controls, such as administrative costs, the Company participates in various committees at PJM and could protest any inappropriate costs, and that either DNCP or the IMM could complain to FERC if there are disagreements with PJM. He also confirmed that in the Company's 2014 fuel case, even though DNCP's fuel costs as a PJM member were lower than they would have been had DNCP operated as a separate control area, FTR and ARR revenues were used to offset congestion costs that the Company incurred in order to gain the benefits of PJM participation. He confirmed that over $1 million from those FTR and ARR revenues were offset against those costs, which he viewed as one way in which the continuance of the conditions would be unfair.

On redirect, witness Hupp confirmed that the cost-benefit analysis included in the Company's Supplemental Filing was conducted at the request of the Public Staff, and that it built on the PJM Integration Studies that DNCP conducted as part of its fuel cases from 2006-2015. He agreed that in addition to the market energy costs addressed in those fuel case studies, the cost-benefit analysis also evaluated FTRs, capacity, transmission costs, ancillary services, and administrative costs, and that the overall result showed a substantial financial benefit to the North Carolina retail jurisdiction from DNCP joining PJM. He clarified that the reporting requirements that witness McLawhorn has asked to be continued were part of the JOS with PJM, and that DNCP is requesting relief from all of the conditions in the other settlement agreement in the PJM case, which was with Progress Energy Carolinas, Inc., now Duke Energy Progress, LLC (DEP). He testified that the Company conferred with DEP on all of the conditions contained in that settlement agreement and that DNCP and DEP agreed that all of them are being addressed now under other agreements. Finally, witness Hupp testified on redirect that the Company has for the past 11 years not been allowed to recover significant costs of doing business due to the PJM Order conditions. He testified that the Company is now seeking to be allowed the chance to recover all of the costs of providing reliable and least cost service to its customers.

In response to Commission questions, witness McLawhorn testified to his recommendation that the Company continue to file the information required by Paragraphs 5 and 6 of the JOS. He agreed that it would be sufficient for the PJM IMM to resume filing the Paragraph 6 information as it had done previously.

The post-hearing exhibit filed by DNCP and the Public Staff shows that, as stated in witness Hupp's testimony, all of the conditions imposed by the PJM Order are now either no longer applicable or are being met under subsequent and currently effective agreements, with the exception of the ongoing reporting requirements agreed to in the Stipulation. The exhibit also noted PJM's confirmation that all of the conditions are now covered elsewhere or no longer apply.

The Commission finds the testimony of Public Staff witness McLawhorn persuasive. He concluded that DNCP's cost-benefit analysis methodology and assumptions were reasonable, and that even if the quantification was overstated, there has been a net economic benefit to DNCP's customers from PJM membership. Witness McLawhorn also stated, based on the most current projections of natural gas prices, capacity prices and other PJM-related costs, the Public Staff expects the net economic benefits of DNCP's membership in PJM to continue. The Commission agrees with witness McLawhorn that it has full authority to ensure DNCP's compliance with the representations the Company made in the Supplemental Filing, and that any additional PJM-related costs that the Company seeks to recover will only be recoverable if the Company shows them to have been reasonable and prudently incurred.

The evidence presented in this case demonstrates that DNCP's integration into PJM has benefited its customers, and that those benefits can be expected to continue even if the Commission relieves the Company from compliance with most of the PJM Order conditions. Going forward and as clarified at the hearing and in witness McLawhorn's testimony, DNCP will be required to show that costs incurred with respect to PJM membership are reasonable and were prudently incurred, just as with any other costs for which the Company seeks recovery. The Commission fully expects Dominion to use its voice in various PJM committees at PJM to protest any inappropriate PJM-related costs, to complain to FERC if there are irreconcilable disagreements with PJM adversely affecting its North Carolina ratepayers, and to communicate any such concerns to the Commission and the Public Staff. Therefore, the Commission concludes that based on all of the evidence presented, it is appropriate to grant the Company's request for relief from most, but not all, of the conditions imposed by the PJM order.

The Company shall continue to comply, or shall compel PJM's independent market monitor to comply, with the reporting obligations established in Paragraphs 5 and 6 of the JOS and as provided at Section XIV of the Stipulation. The Company shall also continue to meet the five commitments that it agreed to be subject to as a North Carolina regulated retail electric utility and as it stated in its Supplemental Filing. Finally, the Company shall make a compliance filing in this docket within 30 days of the issuance of this Order, which filing shall consist of a comprehensive Code of Conduct that shall include all of the ongoing obligations and commitments to which the Company agrees to be bound, consistent with its representations, the Stipulation, and this Order. This filing shall include conditions that predate the PJM Order. The Public Staff is requested to review the filing and provide comments to the Commission within 30 days.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 51

The evidence supporting this finding of fact and these conclusions is contained in the testimony and exhibits of the Company and Public Staff, and in the Stipulation.

As fully discussed above, the provisions of the Stipulation are the product of the give-and-take of settlement negotiations among DNCP, the Public Staff, and CIGFUR I. Comparing the Stipulation to DNCP's Application, and considering the direct testimony of the Public Staff witnesses, the Commission observes that there are provisions of the Stipulation that are more important to DNCP, and, likewise, there are provisions that are more important to the Public Staff. For example, DNCP is intent on obtaining deferral of the post-in-service costs of the Brunswick County and Warren County CC generating facilities, as well as deferral of the Chesapeake Energy Center impairment and closure costs. Indeed, the depth of DNCP's commitment to obtain deferral of the Warren County CC costs is evident from the fact that DNCP filed for reconsideration of the Commission's March 29, 2016 Order denying deferral of those costs. On the other hand, the Public Staff is intent on limiting DNCP's Marketing Percentage for the fuel cost of purchase power to 78%, substantially lower than the 100% sought by DNCP. Further, the Public Staff is focused on resisting any increase in the basic facilities charge component of DNCP's rates. Nonetheless, working from different starting points and different perspectives, the Stipulating Parties were able to find common ground and achieve a balanced settlement.

In addition, the Commission notes that the Stipulation provides customer benefits that are beyond what the Commission has the authority to require of DNCP. These include the $400,000 shareholder contribution by DNCP to the EnergyShare program that provides energy assistance to customers in need in the Company's North Carolina service territory; DNCP's withdrawal of its request for recovery of the site separation costs associated with the proposed North Anna 3 nuclear plant; and DNCP's accelerated refund of its fuel cost over-recovery through Rider A1.

The result is that the Stipulation strikes a fair balance between the interests of DNCP and its customers. As discussed above, the Commission has fully evaluated the provisions of the Stipulation and concludes, in the exercise of its independent judgment, that the provisions of the Stipulation are just and reasonable to all parties to this proceeding in light of the evidence presented, and serve the public interest. The provisions of the Stipulation strike the appropriate balance between the interests of DNCP's customers in receiving safe, adequate, and reliable electric service at the lowest possible rates, and the interests of DNCP in maintaining the Company's financial strength at a level that enables the Company to attract sufficient capital. As a result, the Commission concludes that the provisions of the Stipulation are just and reasonable under the requirements of the Public Utilities Act. Therefore, the Commission approves the Stipulation in its entirety. In addition, the Commission finds and concludes that the Stipulation is entitled to substantial weight and consideration in the Commission's decision in this docket.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 52

The evidence for this finding of fact and these conclusions is contained in the Application, the testimony and exhibits of the DNCP witnesses and the Public Staff witnesses, the Stipulation, and the record as a whole.

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

For example, DNCP witness Curtis testified that during the last three years the Company invested $2.3 billion to bring online a total of 2,700 MW of new generation. Witness Curtis stated that this new generation is cleaner and more highly-efficient combined cycle generating capacity that has the potential to create substantial fuel savings due to very favorable current natural gas prices. Witness Curtis cited in particular the operation of the Warren County CC since December 2014, and stated that this facility has created system-wide fuel savings of approximately $65.9 million when compared to wholesale market power purchases. In addition, he stated that the Brunswick County CC is expected to produce similar fuel savings and operational benefits.

Witness Curtis further testified that DNCP has spent approximately $170 million on transmission improvements in North Carolina during the last three years. He stated that these improvements support improved reliability of the transmission system and local economic growth. He also testified that the Company plans to invest an additional $243 million in transmission improvements in North Carolina from 2016 through 2019.

In addition, witness Curtis testified that DNCP has invested over $102 million in its distribution system in North Carolina during the last three years. He stated that these investments balance the need for reliable service with prudent spending.

Witness Curtis also testified regarding the impact of current and proposed environmental regulations on the Company's operations. He stated that during the last decade electric utilities have been required to address compliance with a suite of new environmental standards adopted by the United States Environmental Protection Agency (EPA). He testified that compliance with these standards has had a direct impact on DNCP's operation of its coal-fired generating plants, citing as an example the EPA's Mercury Air Toxics Standards Rule (MATS). Witness Curtis stated that the cost of complying with MATS was a primary driver in the Company's decision to retire over 900 MW of coal-fired generating capacity. He also discussed the impact of the EPA's CCR Final Rule.

Moreover, witness Curtis testified that DNCP has invested approximately $296 million since 2014 to increase security at its transmission substations and at other critical points in its infrastructure. Further, he stated that the Company plans to invest an additional $260 million for such purposes between 2016 and 2018.

In addition, Company witness Mitchell described the 2013 conversion of the Altavista, Hopewell and Southampton Power Stations from coal-burning facilities to renewable biomass-fueled generation facilities.

These are representative examples of the capital investments that have been made and are planned to be made by DNCP in order to continue providing safe, reliable and efficient electric service to its customers. Based on all of the evidence, the Commission finds and concludes that the rates established herein strike the appropriate balance between the interests of DNCP's customers in receiving safe, reliable and efficient electric service at the lowest possible rates, and the interests of DNCP in maintaining the Company's financial strength at a level that enables the Company to attract sufficient capital. As a result, the Commission concludes that the rates established by this Order are just and reasonable under the requirements of G.S. 62-30, et seq.

IT IS, THEREFORE, ORDERED as follows:

1. That the Stipulation filed by DNCP, the Public Staff, and CIGFUR I is hereby approved in its entirety.

2. That DNCP shall be allowed to increase its rates and charges effective for service rendered on and after January 1, 2017, so as to produce an increase in gross annual revenue for its North Carolina retail operations of $25,790,000, consisting of an increase of $34,732,000 in base non-fuel revenues, and a decrease of $8,942,000 in base fuel revenues.

3. That the proper aggregate base fuel factor for this proceeding is 2.070¢/kWh, excluding regulatory fee, and 2.073 ¢/kWh, including regulatory fee. The Company shall replace the voltage-differentiated base fuel factors approved in Docket No. E-22, Sub 479, with the following voltage-differentiated base fuel factors, including gross receipts tax, effective January 1, 2017:

Customer Class	Base Fuel Factor
Residential	2.095 ¢/kWh
SGS & PA	2.093 ¢/kWh
LGS	2.079 ¢/kWh
NS	2.014 ¢/kWh
6VP	2.043 ¢/kWh
Outdoor Lighting	2.095 ¢/kWh
Traffic	2.095 ¢/kWh

4. That the jurisdictional and class cost allocation, rate designs, rate schedules, and service regulations proposed by the Company, except as specifically addressed in this Order, are approved and shall be implemented. As discussed in this Order, DNCP shall continue to offer Nucor service pursuant to the terms and conditions of Schedule NS and the Nucor agreement approved on March 29, 2016 in Docket No. E-22, Sub 517, as modified to reflect the authorized change in non-fuel base revenues.

5. That DNCP shall implement Rider EDIT as shown on Settlement Exhibit IV via a rate that is calculated using the sales shown in Column 1 of Company Rebuttal Exhibit PBH-1, Schedule 11. Prior to the tenth month from the effective date of the Year 2 rider, the Company shall provide an analysis to the Public Staff to evaluate if the total rider credit will be provided at the end of Year 2. If there is a deviation between the total rider credit and the projected credit provided to customers, the Company and the Public Staff shall work together to develop an adjustment to the Rider EDIT to minimize the deviation over the remaining months of Rider EDIT being in effect.

6. That as soon as practicable after the date of this Order, DNCP shall file for Commission approval five copies of rate schedules designed to comply with the rate design approved in this Order accompanied by calculations showing the revenues that will be produced by the rates for each schedule. This shall include a schedule comparing the revenue produced by the filed schedules during the test period with the revenue that will be produced under the rate schedules to be approved herein and a schedule illustrating the rates of return by class based on the revenues produced by the rates for each schedule.[30]

[30] If necessary, the Commission will address in a subsequent order any refund due based on the any differences in the rates approved in this Order and the Company's temporary rates implemented on November 1, 2016.

7. That as soon as practicable after the issuance of the last Commission Order in DNCP's four pending rate-related proceedings, which are this proceeding, the Sub 534 fuel charge adjustment proceeding, the Sub 535 renewable energy and energy efficiency portfolio standard (REPS) cost recovery proceeding, and the Sub 536 demand-side management proceeding, DNCP shall file a consolidated proposed customer notice addressing the rate changes associated with the non-fuel base and base fuel rate changes approved in this proceeding (Sub 532), the Fuel Rider B in the Sub 534 proceeding, the Rider RP and RPE rate changes in Sub 535, and the demand-side management Rider C and Rider CE rate changes in Sub 536. Such notice shall include the effect of each rate-related proceeding on a residential customer using 1,000 kWh and the combined effect of all four rate-related proceedings on a residential customer using 1,000 kWh. Upon approval by the Commission, DNCP shall notify its North Carolina retail customers of the foregoing rate adjustments by including the approved notice as a bill insert with customer bills rendered during the next regular scheduled billing cycle.

8. That the Company may use levelization accounting for nuclear refueling costs as described in this Order.

9. That the Company shall continue to annually file a cost of service study with the Commission using the Summer/Winter Peak and Average methodology.

10. That the Company shall comply with Commission Rule R8-27(a)(2) regarding future establishments of regulatory assets and liabilities as provided at Section XI.D of the Stipulation.

11. That the Company shall file with the Commission, on the same date it files its quarterly ES-1 report, a report detailing: (1) the CCR deferrals recorded in the reporting period; and (2) regulatory accounting entries pursuant to the August 6, 2004 Order in Docket No. E-22, Sub 420, with regard to any costs other than nuclear decommissioning costs or CCR costs recorded in the reporting period.

12. That the Company shall notify the Commission when the Yorktown Power Station closure occurs and provide estimates of its undepreciated value at the time of closure and the level of costs to be incurred for closure.

13. That with the exception of the commitments in DNCP's July 8, 2016 Supplemental Filing, the Stipulation, and Commission-imposed conditions that predate DNCP's integration into PJM, DNCP is hereby relieved of the PJM Order conditions. Within 30 days of this Order the Company shall file in this docket a compliance filing which shall consist of a comprehensive Code of Conduct that includes all of these ongoing conditions and obligations, including those that predate the PJM Order. The Public Staff is requested to review the Code of Conduct and provide comments within 30 days of DNCP's compliance filing.

14. That the Company shall continue to file the information referenced in Paragraph 5 of the Joint Offer of Settlement dated December 16, 2004, between DNCP and PJM with its annual fuel clause adjustment filing.

15. That prior to DNCP filing its next general rate case, the Company shall work with Utilities International to determine whether it can produce an application that would enable an intervenor or the Public Staff to perform certain UI Model functionalities in Excel, generally including manipulating allocation factors to prepare their own cost of service studies in future rate case proceedings.

16. That the Company shall develop and file for Commission approval a new LED schedule for North Carolina jurisdictional customers within one year of this Order.

17. That the Company shall make a one-time shareholder contribution to its EnergyShare program of $400,000, over and above its usual contribution, for the benefit of its North Carolina customers by January 31, 2017.

18. That if DNCP continues to recover any deferred costs for a longer period of time than the amortization period approved by the Commission for those deferred costs, DNCP shall not record those deferred costs in its general revenue accounts, but, rather, shall continue to record all amounts recovered as deferred costs in the specific regulatory asset account established for such deferred costs until the Company's next general rate case.

19. That the Company shall file with the Commission a proposed pilot or experimental Real Time Pricing rate offering no later than July 1, 2017.

20. That DNCP shall provide a written summary of its TOU rates, and its RTP rates, when developed, to each residential customer presently being served and to be served in the future by a smart meter.

21. That the agreement between DNCP and NCSEA regarding DNCP's TOU rate offerings shall be, and is hereby, approved.

22. That the Company shall file an Average and Excess cost allocation methodology in its next North Carolina general rate case, in addition to the cost allocation methodology proposed by the Company.

ISSUED BY ORDER OF THE COMMISSION.

This the 22nd of December, 2016.

NORTH CAROLINA UTILITIES COMMISSION

Linnetta Threatt

Linnetta Threatt, Acting Deputy Clerk