NORTH CAROLINA
PUBLIC STAFF
UTILITIES COMMISSION

December 4, 2020

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

Re: Docket No. E-2, Sub 1193 – Petition 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; and Docket No. E-2, Sub 1219 – Application of Duke Energy Progress, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina

Dear Ms. Campbell:

Attached for filing is the Public Staff's Proposed Additional Findings, Evidence, and Conclusions in the above-referenced docket.

The Public Staff is filing additional findings, evidence and conclusions regarding coal ash related issues under separate cover.

By copy of this letter, I am forwarding a copy to all parties of record by electronic delivery.

Sincerely,

Electronically submitted
s/ Dianna W. Downey
Chief Counsel
dianna.downey@psncuc.nc.gov

DWD/ab

Attachment

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

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

DOCKET NO. E-2, SUB 1219 In the Matter of Application of Duke Energy Progress, LLC for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina DOCKET NO. E-2, SUB 1193 In the Matter of Petition 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	)))))))))))))))	**PUBLIC STAFF'S PROPOSED ADDITIONAL FINDINGS, EVIDENCE, AND CONCLUSIONS**

ADDITIONAL FINDINGS OF FACT

Depreciation

1. Use of a 10% contingency for future "unknowns" in the estimate of future terminal net salvage costs is reasonable in this case.

2. Use of an average service life of 17 years for the Automated Metering Infrastructure (AMI) meters being deployed by DEP is reasonable in this case.

3. The continued use of a 20-year amortization period for Accounts 391 and 397 is reasonable in this case.

4. It is reasonable and appropriate to approve the use of the Public Staff's proposed depreciation rates as shown on McCullar Exhibit RMM-1.

GIP Cost Allocation Study

5. Evidence presented in this proceeding indicates that the Company relied upon cost benefit analyses (CBA) to quantify and justify certain components of its Grid Improvement Program (GIP).

6. Evidence presented in this proceeding indicates that net benefits derived from the CBAs for some of the transmission and distribution assets associated with the Company's GIP may be disproportionally related to the way GIP transmission and distribution plant is currently allocated.

7. Though the National Association of Regulatory Utility Commissioners' (NARUC) Electric Utility Costs Allocation Manual has been and remains a relevant and important resource for the calculation and allocation of

electric utility cost of service, the approach to cost allocation suggested by the Regulatory Assistance Project's (RAP) January 2020 Electric Cost Allocation Manual, particularly as it relates to GIP costs, is worthy of consideration.

8. It is reasonable for the Company, in consultation with the Public Staff and other interested stakeholders, to study the allocation of GIP investments based on the realized benefits of those investments, and report its findings no later than the filing of its next general rate case.

Schedule R-TOUD

9. Schedule R-TOUD should be reopened to all residential customers.

Schedules CSE and CSG

10. The Company should notify customers on Schedules CSE and CSG of other rate schedule options, and work with them to migrate to other schedules by the time of the filing of DEP's next general rate. The rates in Schedules CSE and CSG should be increased by 33% of the revenue gap between them and the MGS class schedules after the increase ordered herein, with another adjustment of 33% of the gap in the next general rate case, and then migration of these customers to the most advantageous MGS schedule by the Company's following rate case.

CIGFUR Stipulation AND EDIT Return

11. The CIGFUR Stipulation is the product of give-and-take in settlement negotiations between DEC and CIGFUR, and it is material evidence entitled to be given appropriate weight by the Commission.

12. It is premature for DEP to agree in advance to use a specific allocation factor or methodology to allocate deferred GIP costs among the customer classes in the next general rate case. At the time DEP seeks to recover its GIP costs (deferred or otherwise), DEP shall propose an appropriate method to allocate GIP costs.

13. It is inappropriate to refund unprotected Excess Deferred Income Taxes and deferred revenue giveback overpaid by customers through the EDIT rider on a uniform cent/kWh basis rather than as a levelized EDIT credit by specific customer-class divided by the adjusted class' test year sales.

14. In regard to the provision of the CIGFUR Stipulation related to the adjustment of peak demands used in the Company's cost of service studies to allocate certain demand-related costs is accepted, it is appropriate for the Company to adjust all peak demand hours incorporated into the peak demand inputs used in various COSS methodologies, but only to the extent that the Company actually realized a level of demand reduction based on it calling on or activating a demand reduction resource (DSM program or interruptible load program) for the specific hour under consideration. If an adjustment is made, the Company shall impute the total amount of available resource for all customer classes as appropriate as if the entire portfolio of DSM and interruptible resources were called.

15. The Commission declines to require the Company to propose the uniform percentage average bill adjustment methodology in its 2021 and 2022 annual fuel cost proceedings.

16. The Commission declines to approve the provision of the CIGFUR Stipulation requiring DEP to propose the Minimum System Method (MSM) for determining classification of distribution costs for specific rate schedules in a future proceeding. Instead, the appropriateness of use of the MSM shall be considered in the comprehensive rate design study.

17. It is appropriate for the Company to include in its comprehensive rate study a discussion of the various rate schedules as discussed in Section E of the CIGFUR Stipulation.

18. Based upon all of the evidence in the record, the Commission accepts in part, the CIGFUR Stipulation as modified herein, and finds that those provisions that are accepted are just and reasonable to the customers of DEP and to all parties to this proceeding, and serve the public interest. In addition, the CIGFUR Stipulation as modified is entitled to substantial weight and consideration in the Commission's decision in this docket.

Commercial Group/Harris Teeter Stipulations

19. It is inappropriate to require the Company to recover its GIP-related costs solely through demand rates in Rate Schedule SGS-TOU or any other rate schedule that includes a demand rate.

20. For purposes of setting rates in this proceeding, the Commission finds reasonable the terms related to percentage base rate increase for Rate Schedules SGS-TOU and MGS, with the exception of Rate Schedules CSE and CSG as discussed herein. However, the Company shall study Rate Schedules

SGS-TOU and MGS in the comprehensive rate study and propose all appropriate adjustments in the next proceeding.

21. Based upon all of the evidence in the record, the Commission accepts in part, the CG/HT Stipulations as discussed herein, and finds that those provisions that are accepted are just and reasonable to the customers of DEP and to all parties to this proceeding, and serve the public interest. In addition, the CG/HT Stipulations as modified are entitled to substantial weight and consideration in the Commission's decision in this docket.

Credit Metrics

22. N.C.G.S. 62-133 sets forth the factors to be considered by the Commission in setting rates for public utilities.

23. N.C.G.S. 62-133(a) states in fixing rates the Commission shall fix such rates as shall be fair to both the public utilities and to customers.

24. N.C.G.S. 62-133(d) states the Commission shall consider all other material facts of record that will enable the Commission to determine reasonable and just rates.

25. There is no requirement in N.C.G.S. 62-133 that the Commission consider the utility's credit ratings or stock price in fixing just and reasonable rates.

26. While the Commission's decision must consider the impact its decision will have on the utility's ability to access capital markets, it is the responsibility of the utility's management to prudently manage the utility in a manner that supports the utility's credit ratings and the stock price.

27. The rates fixed by this Commission will not harm the ability of Duke Energy and its subsidiaries, through prudent management, to access the capital markets on reasonable terms.

28. The rates fixed by this order are fair to both DEP and customers and produce just and reasonable rates.

Revenue Requirement

29. It is just and reasonable to adopt the base revenue requirement recommended by the Public Staff in Public Staff witness Maness's Second Stipulation Exhibit 1 of $264,978,000.

30. After giving effect to the approved Stipulations and the Commission's decision on contested issues, the annual revenue requirement of $264,978,000 will allow the Company a reasonable opportunity to earn the 6.9336% rate of return on its rate base that the Commission has found just and reasonable.

31. The appropriate base revenue requirement for the first two years should be reduced by the State EDIT Rider and the Deferred Federal provisional EDIT Rider decrements of $71.708 million each year.

32. The appropriate base revenue requirement for the first five years should be reduced by the unprotected Federal EDIT Rider decrement of $94.415 million each year, and will be recalculated by the Company to remove the actual amounts refunded to ratepayers during the period interim rates were in effect.

33. The appropriate base revenue requirement for the first year should be reduced by the refund of the regulatory asset/liability rider decrement of $2.091 million.

34. The total revenue requirement for year 1, as reflected in Public Staff Maness's Second Stipulation Exhibit 1 is $96,764,000. This amount is subject to the final actual Federal unprotected EDIT remaining to be refunded after the amounts actually refunded in interim rates.

35. The total revenue requirement for year 2, as reflected in Public Staff Maness's Second Stipulation Exhibit 1 is $98,855,000. This amount is subject to the final actual Federal unprotected EDIT remaining to be refunded after the amounts actually refunded in interim rates.

36. The total revenue requirement for years 3 through 5, as reflected in Public Staff Maness's Second Stipulation Exhibit 1 is $170,563,000. This amount is subject to the final actual Federal unprotected EDIT remaining to be refunded after the amounts actually refunded in interim rates.

37. Since the Company will need to provide updated Federal unprotected EDIT amounts to refund to ratepayers due to the return of some of the EDIT in interim rates, DEP should recalculate and file the annual revenue requirement in the same format as Maness Second Stipulation Exhibits 1 and 2, with the Commission within ten days of the issuance of this Order, consistent with the findings and conclusions of this Order. The Company should work with the Public Staff to verify the accuracy of the filing. DEP should file schedules

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.

ADDITIONAL EVIDENCE AND CONCLUSIONS

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-4

[Depreciation]

Depreciation Rates

Company witness Spanos introduced Spanos Exhibit 1, a report entitled "2018 Depreciation Study - Calculated Annual Depreciation Accruals Related to Electric Plant as of December 31, 2018" (Depreciation Study) prepared by Gannett Fleming Valuation and Rate Consultants, LLC. (Tr. vol. 11, 189.) As explained by witness Spanos, the Depreciation Study was to estimate the annual depreciation accruals related to electric plant in service for ratemaking purposes and to determine appropriate average service lives and net salvage percentages for each plant account. The Depreciation Study included dismantlement or decommissioning cost estimates for all steam, hydraulic, and other production plants that are based on decommissioning studies of each generating site performed by Burns and McDonnell, an external engineering firm. (Id. at 222.)

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. The life span estimates for nuclear and hydro facilities that have operating licensees were based on the license expiration dates for each facility. (Id. at 218.) The life spans estimates used for depreciation rates for various fossil plants were also updated due to changes in the probable retirement dates, with the life spans at Mayo Unit 1 and Roxboro Units 3 and 4 proposed to be shorted 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 described 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 ($68 million) of the legacy meters will be amortized over 10 years. (Id. at 219.) Finally, 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.)

FPWC witness Brunault recommended two changes of assumptions used in the 2018 Depreciation Study. He first 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 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 pp. 69-71.)

On the issue of depreciation, the Public Staff presented the testimony of Roxie McCullar, a consultant with the firm of William Dunkel and Associates. Ms. McCullar testified that based on December 31, 2018 investments, DEP was proposing an increase in its depreciation annual accrual of $145 million. (Tr. vol. 15, 781.) Based on Ms. McCullar's investigation, the Public Staff recommended an increase in DEP's depreciation annual accrual of approximately $78.6 million based on December 31, 2018, investments, a decrease of $66.4 million from the amount proposed by the Company. (Id.) The difference between the Company's and the Public Staff's proposed deprecation annual accrual results in part from witness McCullar's use of the expected final retirement dates recommended by Public Staff witnesses Shawn Dorgan and Dustin Metz for Mayo Unit 1 and Roxboro Units 3 and 4 in the calculation of the Public Staff's proposed depreciation rates, consistent with the retirement dates used in the Sub 1142 Proceeding, rather than the earlier retirement dates proposed by DEP in this proceeding. The remaining difference between the Company's and the Public Staff's proposed depreciation annual accrual results from four adjustments proposed by Ms. McCullar, as discussed below.

Contingency

Public Staff witness McCullar recommended that the current 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.) Ms. McCullar noted that in the Sub 1142 Order, the Commission approved the use of a 10% contingency factor consistent with the stipulation between DEP and the Public Staff, instead of the 20% contingency factor requested by DEP and included in the DEP Decommissioning Cost Estimate Study filed as Doss Exhibit 5 in that docket. She noted that in its June 22, 2018 *Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction* in Docket No. E-7, Sub 1146, the Commission stated 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. (Id. at 603, quoting from Sub 1146 Order at pp. 172-73).

Ms. McCullar noted that DEP's proposed future terminal net salvage costs are again supported by the same DEP Decommissioning Cost Estimate Study reviewed in the Sub 1142 Proceeding.

DEP witness Spanos disagreed 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 percent 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.)

The Commission agrees with DEP 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 DEP has presented no new information or data supporting the need for a contingency percentage greater than the 10% contingency agreed to by stipulation in the Sub 1142 Order, or the 10% contingency approved by the Commission in the Sub 1146 Order. In that proceeding, the Commission expressed some concern regarding the accuracy of the DEC's Decommissioning Study, finding that the study failed to take into account certain factors and noting that "[w]hile it is impossible to anticipate all future costs, merely being able to identify possible future costs or costs incurred for other projects is not the most firm basis on which to calculate contingency." (Sub 1146 Order at 172.) As a result, the Commission found that a 10% contingency was fair to all parties, and that the Commission was "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." (Id. at 172-73.)

The Commission acknowledges Mr. 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, while Mr. Spanos discusses the historical treatment of coal ash costs in depreciation studies, which are addressed separately in this order, he does not provide any new data or information to support his claims 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.

AMI Meter Average Service Life

The Public Staff's similarly recommended that the Company adjust its proposed 15-year average service life for depreciation purposes for its Advanced Metering Infrastructure (AMI) meters to 17 years. Ms. McCullar recommended that a service life of 17 years be used, in part based on DEP's limited experience with AMI meters. In addition, Ms. McCullar noted that the manufacturer's expected life was 15-20 years, so using a life in the middle of the manufacturer's expected range is a reasonable estimate that is fair to both the Company and the ratepayer. (Tr. vol. 15, 791-92.)

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. (Tr. vol. 16, 296-97.) He recommended to continue 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.)

The Commission finds that it is reasonable to continue to use an average service life of 17 years for new AMI meters for DEP, which is even below the middle of the manufacturers' range. While DEP has pointed out certain technological characteristics of AMI meters, it has not shown that the manufacturers' estimates were high, inaccurate, or unreliable. In addition, DEP did not present any data supporting the retirement of meters that would be expected of the 15-S2.5 survivor curve on which it based its depreciation rates. As such, the Public Staff's proposal to rely on the midrange of the manufacturer's estimate for average service life is reasonable.

Mass Property Future Net Salvage

The Depreciation Study included as Spanos Exhibit 1 provided support for determining net salvage estimates for each plant account. 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" for the period 1979 through 2018; information provided by the Company's operating personnel, general knowledge and experience of industry practices; and general industry trends. (Tr. vol. 11, 220-21.) He further testified that the statistical net salvage analysis included an analysis of trends based on three-year moving averages and the most recent five-year indications. (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 DEP's proposed depreciation accrual and the actual net salvage costs incurred by DEP on average over the recent five-year period. (Tr. vol. 15, 799.) Ms. 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 795-98.) Table 4 included in Ms. McCullar's testimony provided a comparison of the actual net salvage costs incurred by DEP on average over the recent five-year period to future net salvage costs included in DEP's and the Public Staff's proposed depreciation accruals. Ms. McCullar testified that her analysis provides a "reasonableness check" of the proposed future net salvage percents, and 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 my previous experience." (Id. at 801.) As a result of her analysis, for Mass Property Distribution Accounts 364, 366, and 369, Ms. McCullar future net salvage percentages of -75%, -10%, and -15%, respectively, which differed from DEP's proposed -100%, -15%, and -20%, respectively. (Id. at 792.) Ms. McCullar noted that even under her recommendation, the annual accrual for

Account 364, Poles, Towers, and Fixtures, net salvage would still be $11,558,347, which is about 20.4 times the average annual amount DEP actually incurred. She further testified that her recommendations provide recovery of the expected cost of removal in the near future and builds reserves for the future cost of removal associated with future retirements. (Id. at 801-2.)

DEP witness Spanos in rebuttal stated that the existence of a small number of instances where different approaches were used does not indicate that DEP's approach is consistent with the method used in the vast majority of jurisdictions. (Tr. vol. 16, 287.) He stated that Ms. McCullar's recommendations for production plant accounts were consistent with the Commission's decision in the Sub 1146 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 Ms. 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.)

On cross-examination, Mr. Spanos acknowledged that while the Commission had concluded in the Sub 1146 Order that production plant accounts should be escalated to the date of retirement, they had not made such a finding related to mass property salvage accounts. (Id. at 373-74.) Further, he acknowledged that the FERC Order he discussed in his testimony addressed the decommissioning component, which would only apply to production accounts, but not mass property net salvage accounts. (Id. at 376.)

Mr. Spanos acknowledged that the Kansas State Corporation Commission (KSCC) in a recent decision supported the approach taken by witness McCullar in proposing future net salvage accrual amounts that considered historic practices, the impact of inflation, built a reserve for reasonable estimated future net salvage removal, and professional judgment. (Id. at 388-89, citing *Order on Atmos Energy Corporation's Application for a Rate Increase* at paragraphs 52-54; KSCC Docket No. 19-ATMG-525-RTS (February 24, 2020)) He further agreed that the KSCC found that the net salvage analysis used 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. at 392-94.)

The Commission agrees with Duke that there will not necessarily be alignment between depreciation accruals for net salvage and incurred net salvage in each year over the life of an asset, but recognizes the goal of balancing those values equitably over the service life of the assets. The Commission finds that the Public Staff witness McCullar's recommendation properly considers the range of the historic net salvage percents and sufficiently provide a reserve for future removal costs, while balancing the interests of current versus future ratepayers. Therefore, the Commission finds that the Public Staff's proposed future net salvage percentages for Accounts 364, 366, and 369 are reasonable and should be utilized in this proceeding.

Amortization Period for General Plant Accounts

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. Ms. McCullar notes 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.) Ms. 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, whether or not that asset is still in service. 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.)

Ms. McCullar noted 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.

In his rebuttal testimony, DEP witness Spanos acknowledged that the amortization periods proposed by Ms. McCullar were consistent with those approved by the Commission in the Sub 1142 proceeding, but noted that the amortization periods he proposed were consistent with those approved by the Commission for use by DEC in the Sub 1146 proceeding. He stated there was no compelling reason for DEP to use a different amortization period for these accounts than DEC, and noted that Ms. McCullar was a witness in the current DEC case in Docket No. E-7, Sub 1214, but did not challenge the amortization periods for these two accounts in that case. (Id. at 305-06.) He further took issue with Ms. McCullar's previous analysis in the Sub 1142 proceeding 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.)

Mr. Spanos also stated that there were errors in Ms. 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.) However, on cross-examination, Mr. Spanos clarified that Ms.

McCullar was using the same initial investment amount for these assets, but that to properly restore the depreciation expense for these accounts to the original 20-year amortization period, additional adjustments to the reserve allocation to certain vintages would be necessary. (Id. at 383-86.)

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 Mr. 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 Ms. 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 on Depreciation

Based on the foregoing conclusions regarding the continued use of the current approved final retirement year for Mayo Unit 1 and Roxboro Units 3 and 4, the use of a 10% contingency for future “unknowns” in the estimate of future terminal net salvage costs, the use of an average service life of 17 years for new AMI meters being deployed, the use of the net salvage analysis proposed by the Public Staff, and the continued use of a 20-year amortization period for Accounts 391 and 397, the Commission finds it is reasonable and appropriate to approve the use of the Public Staff’s proposed depreciation rates as shown on McCullar Exhibit RMM-1.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5-8

[GIP Cost Allocation Study]

The evidence supporting these findings of fact is found in the testimony of Public Staff witnesses Thomas and McLawhorn, and DEP witness Hager.

In his testimony, Public Staff witness Thomas raised concerns about the Company’s allocation of GIP reliability benefits and equity in cost allocation and rate design. He was able to determine from the Company’s own CBAs that claimed customer reliability benefits for C&I customers are estimated at approximately $6 billion, representing over 97% of customer reliability benefits broken out by class, 73% of total customer reliability benefits, and 64% of all GIP program benefits. (Tr. vol. 15, 483-84.) In contrast, residential reliability benefits only comprise 1.8% of all GIP program benefits. (Id. at 484.) He explained that while it can be assumed that all customers benefit equally from the other benefit categories (particularly operational benefits), customer reliability benefits comprise the vast majority of all claimed benefits and their allocation has an enormous impact on the allocation of total GIP benefits. (Id.)

Witness Thomas explained that if there is no new allocation factor proposed for GIP investments, all GIP costs are expected to be allocated among customer classes according to the allocation factors that have historically been used for T&D expenditures. (Id. at 485.) Distribution investments are typically allocated using a non-coincident peak allocation factor; for residential customers, the class factor is approximately 68%.[1] Transmission investments are allocated on a transmission demand allocation factor; for residential customers, the class factor is approximately 50%.[2] (Id. at 485-86.)

Witness Thomas testified that he is not recommending that GIP costs be allocated differently than traditional T&D investments at this time. However, he believes the issue is ripe for Commission consideration, particularly in light of the Commission's *Order Approving Revised Interconnection Standard and Requiring Reports and Testimony* in Docket No. E-100 Sub 101, which requires the Company to "file testimony in [its] next general rate case application[] regarding the benefits that distributed generators are receiving from the Utility's System, estimating their

[1] This number reflects the primary distribution allocation factor found in DEP's per books Cost of Service Study (See E-1 Item 45a).

[2] This number reflects the transmission demand allocation factor found in DEP's per books Cost of Service Study (See E-1 Item 45a). Public Staff witness McLawhorn has proposed utilizing a different cost allocation methodology (SWPA); the corresponding residential retail transmission allocation factor is 56.8%.

share of related costs, and providing options for recovering those costs from distributed generators." He concluded that if the Commission agrees that this issue merits further study, DEC's and DEP's planned study of the impact of distributed generation could be expanded to require an evaluation of possible alternative methods of allocating GIP investments that provide primarily reliability benefits. (Id. at 486.)

In his direct testimony, Public Staff witness McLawhorn noted witness Thomas's testimony on the allocation of GIP investments and recommended that the Commission order DEP to study the allocation of GIP investments based on the realized benefits of those investments, and report its findings no later than the filing of its next general rate case. (Tr. vol. 15, 926.)

In her rebuttal, Company witness Hager proposed allowing the investments associated with GIP to follow the same cost causation principles that are applied to the investments in the same FERC accounts as reflected in the COS study. In her opinion, attempting to allocate any investment costs for ratemaking purposes based on perceived benefits realized by customers, as differentiated from cost causation to the utility, is likely to be very subjective and thus controversial. During the hearing, she characterized the undertaking of the GIP study advocated by witness McLawhorn as a "waste of time" and that it would not be useful for purposes of cost of service because it would be a departure from the principles of cost causation. (Tr. vol. 11, 1067-68, 1178-79.)

In January of 2020, the Regulatory Assistance Project (RAP) published *Electric Cost Allocation for a New Era* (RAP Manual), identified during the hearing as Public Staff Pirro/Hager Cross-Examination Exhibit 1. (Tr. vol. 11 Exhibits 970.) According to its authors, this cost allocation manual is intended to build upon previous manuals on cost allocation, including the 1992 NARUC *Electric Utility Cost Allocation Manual* cited by witness Hager in her testimony. (RAP Manual 15-16.) The RAP Manual illustrates the changes in the electric system that have occurred since the 1990's. The traditional electric system consisted of central general, transmission, and distribution. (Id. at 32, Figure 7.) The modern electric system includes distributed generation, storage, smart appliances, demand side management, and microgrids. (Id. at 33, Figure 8.) With Advanced Metering Infrastructure (AMI) technology, a utility can obtain both more data and more granular data than with older meters, and can perform functions other than measure electric use, such as demand management. (Id. at 18.) The authors of the RAP manual suggest that two primary conceptual principles guide the way for an equitable division of costs among customers: 1) cost causation and 2) costs follow the benefits, and that costs follow benefits is the superior principle in cost allocation. (Id.)

The Commission finds that the electric system has changed in the years since the publication of the NARUC CAM manual in 1992. As the RAP manual indicates, the electric system performs many more functions than just transmitting electricity from a generation source to a customer. Similarly, GIP investments are designed to "transform" the grid, providing benefits that may or may not line up with traditional cost allocation principles. The Commission agrees with the Public Staff that given that the cost burden of GIP may be disproportionate to the benefits received by customers, further study is needed. Therefore, the Commission finds and concludes that the Company, in consultation with the Public Staff and other interested stakeholders, shall study the allocation of GIP investments based on the realized benefits of those investments, and report its findings no later than the filing of its next general rate case.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

[R-TOUD]

The evidence supporting this finding and conclusion is contained in the direct and rebuttal testimony and exhibits of DEP witness Pirro; the testimony and exhibits of Public Staff witness Floyd; and the entire record in this proceeding.

In his direct testimony, Company witness Pirro indicated that the Company was not proposing any structural change to the time-of-use (TOU) hours and rate seasons for the residential TOU schedules at this time. (Tr. vol. 11, 1094.) He noted that the rates for residential Schedule R-TOUD had been adjusted to achieve approximately the same increase as recommended for Schedule RES. (Id.) Mr. Pirro stated that the demand and energy prices in the schedule were adjusted by the same percentage to achieve the revenue target, and that the pricing structure reflects marginal cost. (Id.)

Public Staff witness Floyd testified that Schedule R-TOUD was closed to new customers in the Sub 1023 rate case, except that it remained open to new and existing customers who were served under the TOU compensation provisions of Schedule NM (Net Metering). (Tr. vol. 15, 959-60.) He indicated that the Public

Staff has received a number of requests from customers over the years, who would like service under a demand as provided by Schedule R-TOUD. (Id. at 960.) Mr. Floyd pointed out that Schedule R-TOUD would allow customers to have more control over their energy consumption and recommended that the schedule be reopened. (Id.)

In his rebuttal testimony, Company witness Pirro noted that Schedule R-TOUD is available for existing residential customers if they are served under: (1) Net Metering for Renewable Energy Facilities Rider NM, or (2) Residential Service Time-of-Use Schedule R-TOUD before December 1, 2013, until service is terminated or service is elected under another available schedule. (Tr. vol. 11, 1127-28.) He indicated that in Sub 1023, the Company created a new time-of-use tariff, R-TOU in order to have a single rate design for residential time-of-use customers and restricted the availability of Schedule R-TOUD. (Id. at 1128.) Mr. Pirro stated that Schedule R-TOU offers improved time periods, improved pricing signals, and no demand charges as opposed to R-TOUD. He agreed with Mr. Floyd that the Company should provide customers with more choices regarding their energy consumption, (Id.) However, Mr. Pirro argued that the Company had not planned to reopen in this case, and had therefore not recommended other changes to the rate and R-TOU. He also stated that the Company would not realize its full revenue requirement without a migration adjustment. (Id. at 1128-29.) Mr. Pirro proposed that instead of reopening R-TOUD, Schedules R-TOU and R-TOUD be studied in the comprehensive Rate Design Study. (Id. at 1129.)

The Commission agrees with Public Staff witness Floyd that customers should have choices of rate schedules so that they can manage their electric usage. The Commission also notes Mr. Floyd's testimony that customers have specifically requested to be allowed to be served on R-TOUD. While the Company may see as an advantage of Schedule R-TOU that it does not include a demand charge, other customers may find it advantageous to be served on that schedule, in part, because it does. While the Commission agrees that Schedules R-TOU and R-TOUD should be studied in the Rate Design Study, the Commission finds it in the public interest to reopen Schedule R-TOUD to new customers.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

[Schedules CSE and CSG]

The evidence supporting this finding and conclusion is contained in the testimony and exhibits of DEP witness Pirro and Public Staff witness Floyd; and the entire record in this proceeding.

Company witnesses Pirro discussed the changes to the rates within the Medium General Service (MGS) category, with include Schedules CSE and CSG. (Tr. vol.11, 1096.) He stated that the CSE and CSG schedules, which are frozen, were increased by 15% more than the other schedules within the MGS class to encourage migration to another schedule. He noted that these schedules had been closed to new participants since 1977. (Id. at 1098.) Finally, Mr. Pirro indicated that the Company had reviewed the potential for transferring these customers to other schedules, but did not propose to do so because it would result in a significant increase to these customers. (Id.)

Public Staff witness Floyd testified that Schedules CSE and CSG provide service to churches and church schools, respectively. (Tr. vol. 15, 960.) While some customers have migrated to other schedules since these schedules were closed in 1977, there remain 44 customers on Schedule CSE and one customer on Schedule CSG. (Id.) Information provided to the Public Staff by the Company indicated that migration to other rate schedules would increase the bills of customers on Schedule CSE by an average of 21% and the bill of the one customer on Schedule CSG by 113%. (Id.) Mr. Floyd stated that this indicates that these rates are very likely understated and do not cover the costs to serve these customers. (Id. at 1061.) He also pointed out that keeping these schedules closed for 44 years to other customers allows only a few customers to benefit from subsidized rates, and is therefore discriminatory. (Id.) Mr. Floyd recommended that the Commission require the Company to notify these customers of other rate schedule options, and to work with them to migrate to other schedules by the time of the filing of DEP's next general rate. (Id.) He also recommended that the rates in Schedules CSE and CSG be increased by 33% of the revenue gap between them and the MGS class schedules, with another adjustment of 33% of the gap in the next general rate case, and then migrating these customers to the most advantageous MGS schedule by the Company's following rate case. (Id. at 1061-62.)

The Company did not file any testimony in rebuttal to Mr. Floyd's recommendation and the Stipulations between the Company and the Public Staff did not address these particular rates or Mr. Floyd's proposal. No other parties addressed Mr. Floyd's proposal.

The Commission agrees with Mr. Floyd's recommendation to encourage the migration of the customers on Schedules CSE and CSG to other schedules in the MGS class, and to increase the rates in these Schedules by 33% of the revenue gap between them and the MGS class after the impact of the revenue increase ordered herein. The Commission recognizes that the customers on these Schedules will bear a larger percentage increase than other customers, but these customers have benefited from rates that have been discriminatory to other customers in the MGS Class. The three-step approach recommended by Mr. Floyd should mitigate the increase; further, the Commission is optimistic that new rate options developed through the Rate Design Study ordered herein may provide these customers with new opportunities to reduce their electric bills.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 11-18

[CIGFUR Stipulation and EDIT Return]

The evidence supporting these findings and conclusions is contained in the Application and the accompanying E-1, the entire record of Docket No. E-2, Sub 1219, the testimony of Company witnesses Michael Pirro and Janice Hager, CIGFUR witness Nicholas Phillips, and Public Staff witnesses James McLawhorn and Jack Floyd.

On June 26, 2020, the Company and CIGFUR filed an Agreement and Stipulation of Settlement (CIGFUR Stipulation). No testimony supporting the settlement was filed. The Stipulation provided in Section II for an ROE of 9.75% and a capital structure of 52% equity and 48% debt. It also supported the Company's request for a deferral of Grid Improvement Plan (GIP) costs over three years. On August 6, 2020, the CIGFUR Stipulation was amended to provide that should the Commission approve an ROE of 9.6%, this section of the Stipulation should be deemed to be fulfilled. The Commission has made findings addressing ROE, capital structure, and the GIP deferral i*nfra* that address these terms of the CIGFUR Stipulation.

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 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 cross examination, DEC witness Hager did not disagree with Public Staff counsel's statement that 64% of GIP costs were charged to residential and small general service customers and 10% to OPT-V[3] and large commercial and

[3] OPT-V is a rate schedule offered by DEC to commercial and industrial customers and is generally analogous to DEP Schedule SGS-TOU.

industrial customers. (Tr. vol. 11, 1182.) At the DEC hearing, CIGFUR witness Phillips indicated that Section III.B of CIGFUR's settlement with DEC, which is identical to the same number provision in the settlement between DEP and CIGFUR, would allow the Commission to approve the cost allocation method it has approved for DEC in the past. (Tr. vol. 22, 346.) He also agreed with counsel for the NCJC et al. that the Commission had not considered whether the use of the MSM was appropriate for GIP. (Id. at 348-49.) Mr. Phillips also contended that the DEC CIGFUR Stipulation contained no provisions that would tie the Commission's hands or limit future investigations. (Id. at 341.) Mr. Phillips' DEC testimony was stipulated into the DEP record and is applicable to this provision of the DEP/CIGFUR Settlement.

The Commission finds that it is inappropriate to determine the allocation of deferred GIP costs at this time. The Commission has already accepted the provision in in the Second Partial Stipulation requiring a COS Study, as well as determining the MSM to be appropriate for use for this proceeding. The Commission does not accept this term of the CIGFUR Stipulation because it ties DEP's hands based on a set of facts that may not be appropriate in a future rate case. Each rate case must rely upon its own set of facts and applications of law. Thus, the Commission will only consider future costs, GIP or otherwise, in the context of that future case, as well as the allocation of those costs to the customer classes. As it stands today, the Commission has approved the recovery of some GIP costs in this proceeding which are to be allocated using the appropriate, distribution, transmission, and other allocation factors as determined using the

MSM. Future GIP costs could require a different allocation process and factors. The Commission expects DEP to use the results of the COS Study in future rate cases. To bind itself to use only a particular method at this point is inappropriate. Thus, the Commission finds that it is premature and inappropriate for DEP to agree in advance of a future COS Study to a particular method to allocate deferred GIP costs among the customer classes. The Commission will make that determination in the next general rate case. Therefore, the Commission holds that this provision of the CIGFUR Stipulation is neither just, reasonable, nor in the public interest.

Under Section IV., the parties agreed to refund unprotected Excess Deferred Income Taxes (EDIT) on a uniform cent/kWh basis. In his direct, DEP witness Pirro described how he designed the Year 1 rate for the EDIT Rider by taking the rider revenue requirement, allocating it to each rate classes using the factors appropriate for Accumulated Deferred Income Taxes (ADIT), and dividing each class by the applicable test year retail billed sales. (Tr. vol. 11, 1112.) DEP witness Hager noted that the allocation of the benefits of the EDIT rider based on the ADIT allocator was reasonable based on cost causation principles. (Id. at 1042.) Witness Pirro testified that he used the revenue requirement from Smith Exhibit 4 to develop the rates in Pirro Exhibit 8. (Id. at 1112) 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. (Id. at 1148.) In his Joint Supplemental Rebuttal Testimony, Mr. Pirro noted that returning EDIT as proposed in the CIGFUR Settlement balances out the subsidization of the residential class by non-residential rate classes and is consistent with the rate design in the Company's last rate case. (Id. at 1164.) In the DEC hearing, Mr. 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. (Id. at 1198.) Mr. Pirro admitted that base rates and EDIT should be considered separately. (Id. at 1198-99.) 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. 14, 344.) Public Staff witness Floyd advocated for using Mr. Pirro's original methodology that returned the EDIT to classes based on how much each class had paid. He said 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. (Tr. vol. 15, 1002.) Mr. Floyd also testified that as it was possible to quantify the amount of EDIT paid by each class, and appropriate to return that amount to the class. He cautioned the Commission about taking this overcollection of EDIT to address another problem that was unrelated to the EDIT. (Id. at 1152-53, 1157-58.)

The Commission declines to adopt this provision of the CIGFUR Settlement as it is unreasonable and not in the public interest in this case. EDIT results from the overpayment of taxes by customers associated with the revenues those customers have paid. In other words, those overpayments are determinable from the Company’s books and records of customer billing revenues. While different customer classes may have different rates of return (ROR), the Commission acknowledges that these RORs are highly dependent on the cost of service methodology utilized, as well as the time period during which the cost of service study was calculated. As such, subsidy/excess issues should be resolved on the basis of equity between customer classes and their relationship to the overall ROR resulting from this particular proceeding.

While in prior rate cases for DEC and DEP, use of a uniform EDIT rate was agreed to as part of a settlement, no party contested this issue in those cases, and the Commission accepted the settlement terms on EDIT without making detailed findings of fact as to the appropriateness of a uniform rate. However, we note that in our recent *Order Accepting Public Staff Stipulation in Part, Accepting CIGFUR Stipulation, Deciding Contested Issues, and Granting Partial Rate Increase*, Docket No. E-22, Sub 562, (February 24, 2020) (DENC 562 Order) of which we took judicial notice, the Commission approved the provision of the Stipulation between Dominion Energy North Carolina 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 based upon current rates for 2018. *See* DENC Order at 60-63.

With this issue now squarely before the Commission, the Commission finds it inappropriate to address any subsidy issues through reassignment of EDIT. The Commission finds that returning EDIT credits by customer class is a more equitable method by which to return customers' overpaid EDIT. Thus, the Commission further holds that in this case it is inappropriate to refund unprotected EDIT and deferred revenue giveback overpaid by customers through the EDIT rider on a uniform cent/kWh basis, and rather should be refunded as a levelized

EDIT credit by specific customer-class divided by the adjusted class test year sales.

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 potential cost of service methodologies that the Company may recommend and file 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 to allocate distribution expenses using the MSM in the next three rate cases unless the Commission rejects the method. Finally, the Company also agreed to explore certain rate designs and file the rates if there was interest from CIGFUR customers.

In his second supplemental testimony, Public Staff witness Floyd addressed his opposition to the provision regarding the adjustment to remove curtailable non-firm load, noting that he had agreed in his testimony in Docket No. E-22, Sub 479, to impute the winter peak component as if Dominion had activated all of its available demand-side management (DSM) programs at the time of the winter peak. (Tr. vol. 15, 1003.) He explained that his opposition to the provision in this case was not inconsistent with his position in the Dominion case because Dominion used a COS methodology that equally weighted summer and winter peaks, it activated all DSM and interruptible loads at the time of summer peak, but only a portion at winter peak. Mr. Floyd explained that without the adjustment, the relationship between the two peaks would have been distorted. (Id. at 1003-04.) He also pointed out that, unlike DEP, Dominion used a COS methodology that used an average demand component, thus preventing the interrupted load from avoiding the responsibility of any production plant-related costs, as would occur with a single peak allocator used in this case. (Id. at 1004.)

Mr. Floyd also pointed out that during the test year, DEP activated some of its DSM and interruptible resources at the time of its test year summer and winter peaks, so that the test year summer and winter peaks already incorporate the effects of the reduced demands associated with these resource activations. (Id.) He noted that while DEP only activated a portion of its available demand response resources, the affected customer classes received the benefit of a reduced peak demand allocator in this case. (Id.) Mr. McLawhorn pointed out on cross examination in the DEC case that even if DEC did interrupt load in a future test year, the Public Staff would still oppose such an adjustment as long as DEC continued to rely on a COS methodology that did not include an average component because certain customers would be able to avoid paying for production and possibly transmission plant that they used the vast majority of hours. (Tr. vol. 15, 1067-68, 1095-96.) Mr. McLawhorn and Mr. Floyd agreed that the Public Staff's ultimate position would depend on the COS methodology used by the Company and whether it used interruptible and DSM resources. (Id. at 1096.)

DEP witness Hager indicated that if residential curtailable load is lower than industrial curtailable load, this provision would result in more costs being allocated away from commercial and industrial customers. (Tr. vol. 11, 1185.) CIGFUR witness Phillips stated that when Duke has curtailable load, it does not need to build or buy capacity to serve that load and thus that load should be removed from the demand allocator. (Tr. vol. 14, 338.)

The Commission notes that no party opposed the agreement between DEP and CIGFUR to meet to discuss potential cost of service methodologies that the Company may recommend and the agreement for DEC to file and consider the results of a cost of service study based on the Summer/Winter Coincident Peak method. The Commission finds it reasonable and in the public interest for the Company to consider appropriate COS allocation methodologies and thus approves this provision of the CIGFUR Stipulation.

With respect to adjusting peak demands in cost of service to recognize interruptible load, the Commission gives substantial weight to the testimonies of Public Staff witnesses McLawhorn and Floyd. As described by witness Floyd, the adjustment in the Dominion case was made to recognize the benefits of all demand response resources at the time when Dominion called a portion of those resources. Witnesses Floyd and McLawhorn further explained how a COS methodology based solely on a single coincident peak could impact an adjustment to reflect interruptible loads by distorting the peak demands that would be used to allocate peak demand-related costs (e.g., production and transmission).

The Commission finds it is appropriate for the Company to adjust all peak demand hours incorporated into the peak demand inputs used in various COS methodologies to reflect all available demand response resources (interruptible load and other DSM programs). However, this is limited to the extent that the Company actually realizes a level of demand reduction for the specific hours under consideration. If an adjustment is made, the Company shall impute the total amount of available resource for all customer classes as appropriate as if the entire portfolio of DSM and interruptible resources were called.

Another provision in this section of the Stipulation requires DEP in its next two fuel proceedings to propose the uniform percentage average bill adjustment methodology and to allocate distribution expenses using the MSM in the next three rate cases unless the Commission rejects the method. No evidence explaining why use of the uniform percentage average bill adjustment methodology was appropriate was presented. Use of the MSM is discussed *infra* in the discussion of COS. The Commission rejects both of these provisions as they are not reasonable and in the public interest; again, they tie DEP's hands when it is studying issues that may call for new approaches. Therefore, the Commission declines to require the Company to propose the uniform percentage average bill adjustment methodology in its 2021 and 2022 annual fuel cost proceedings. The Company may do so if it determines that the methodology is appropriate. The Commission also declines to approve the provision of the CIGFUR Stipulation requiring DEP to propose the MSM for determining classification of distribution costs for specific rate schedules in this proceeding. Instead, the appropriateness of the MSM shall be considered in the comprehensive rate study. Finally, this section of the CIGFUR Stipulation also requires the Company to explore certain rate designs and file the rates if there is interest from CIGFUR customers. The Commission has no qualms with this provision and finds it to be reasonable and in the public interest.

Therefore, based upon all of the evidence in the record, the Commission accepts, in part, the CIGFUR Stipulation as discussed herein. In addition, the CIGFUR Stipulation as modified, is entitled to substantial weight and consideration in the Commission's decision in this docket.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 19-21

[Commercial Group / Harris Teeter Stipulations]

The evidence supporting these findings and conclusions is contained in the Application and the accompanying E-1, the entire record of Docket No. E-2, Sub 1219, the testimony of Company witness Michael Pirro, Harris Teeter witness Bieber, Commercial Group witness Chriss, and Public Staff witness Jack Floyd.

On June 8, 2020, the Company and Harris Teeter filed an Agreement and Stipulation of Settlement (HT Stipulation) and on June 9, 2020, the Company and the Commercial Group filed an Agreement and Stipulation of Settlement (CG Stipulation). These settlements are substantially similar. No testimony supporting either settlement was filed. Both Stipulations provided for an ROE of 9.75% a capital structure of 52% equity and 48% debt. They also contained provisions wherein Harris Teeter and the Commercial Group agreed not to oppose the Company's request for a deferral of GIP costs over three years. On August 6, 2020, both Stipulations were amended to state that should the Commission approve an ROE of 9.6% applied to a capital structure of 52% equity, 48% debt, Paragraph 4 of each Stipulation should be deemed to be fulfilled. The Commission has made findings addressing ROE, capital structure, and the GIP deferral i*nfra* that address these terms of the CG/HT Stipulations.

Both Stipulations include a provision agreeing that any GIP costs allocated to SGS-TOU customers will be recovered through SGS-TOU demand charges. Public Staff witness Floyd stated that the Public Staff has not advocated for recovery of a particular type of cost through a particular rate element, i.e., a demand rate to recover demand costs. (Tr. vol. 15, 1084-85.) Mr. Floyd stated that GIP costs had elements of demand and customer-related classifications and that there was debate as to whether they also had energy elements as well. (Id. at 1086.)

The Commission finds that assigning specific costs to be recovered through specific rate elements places constraints on the rate designer and the Company that could distort and frustrate the overall objectives of cost recovery. While there may be some unique circumstances that would justify such specificity, they would need to be carefully studied to ensure that they do not produce a significant cost shift among all customers. No such evidence of this type of study has been introduced in this case. As such, the Commission finds that it is inappropriate to require the Company to recover its GIP-related costs solely through demand rates in a rate schedule that includes a demand rate. Therefore, the Commission holds that this provision of the CG and HT Stipulations is unreasonable and not in the public interest.

The CG and HT Stipulations also provide that the percentage base rate increase for Rate Schedule SGS-TOU and Rate Schedule MGS shall be the same. The two Stipulations further provide that the SGS-TOU on-peak and off-peak energy charges shall be increased by a percentage amount that is equal to half of the overall percentage increase for the SGS-TOU rate schedule. Additionally, the agreements provide that the demand charges for the SGS-TOU rate schedule shall be adjusted by the amount necessary to recover the final SGS-TOU revenue target.

HT witness Bieber advocated aligning rate design with underlying cost causation to minimize cross-subsidization and better reflecting unit cost from the embedded cost of service study. (Tr. vol. 15, 235-38.) In his rebuttal testimony, Company witness Pirro argued that it is not appropriate to base rate designs solely on embedded unit cost, and pointed out that the Company's rate design considers both embedded and marginal demand cost. (Tr. vol. 11, 1132.) He noted that considering marginal cost in rate design is important so that customers receive efficient electric price signals. (Id. at 1132-33.) Thus, Mr. Pirro stated that the Company proposes to increase demand and energy rates in the SGS-TOU Schedule by the same percentage to recognize both the rate class embedded unit cost and marginal cost. (Id. at 1133.) In his supplemental rebuttal testimony, witness Pirro stated that the changes to the SGS-TOU rate provided for in the HT/CG Stipulations were reasonable based on cost causation. (Id. at 1166.)

In his second supplemental testimony, Public Staff witness Floyd cautioned that the CG and HT Stipulations could impact the proposed rate design study by constraining the freedom to design particular rate elements. (Tr. vol. 15, 1006.) On cross examination, Mr. Floyd indicated that he did not have an issue with the proposed rate design changes to Schedule SGS-TOU *per se*, but recommended that the Commission take a cautious approach. (Tr. vol. 11, 1125-26.) He said that based on Mr. Pirro's representation that the proposed changes to Schedule SGS-TOU are cost-based as opposed to an across the board percentage change, the Public Staff would be supportive of the proposed changes to SGS-TOU for purposes of this case. (Id. at 1127.)

The Commission finds that for purposes of setting rates in this proceeding, the terms related to the on- and off-peak energy rates that would apply to SGS-TOU in the CG and HT Stipulations are reasonable and in the public interest. However, the Commission's finding here should not be interpreted as binding or constraining in any way on the comprehensive rate study and any adjustment or change to that rate that may be recommended by the rate study.

Therefore, based upon all of the evidence in the record, the Commission accepts the CG/HT Stipulations as modified herein, and finds that those provisions are just and reasonable as noted herein, and serve the public interest. In addition, the CG/HT Stipulations, as modified, are entitled to substantial weight and consideration in the Commission's decision in this docket.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 22-28

[Credit Metrics]

Summary of the Testimony

DEP witness Karl Newlin testified in his direct testimony that he is Senior Vice President, Corporate Development and Treasurer for Duke Energy. He testified that under his supervision, the Treasury Department arranges and executes all capital raising and liquidity transactions, including credit facilities and commercial paper, debt securities, preferred and hybrid securities, and common stock, as well as daily cash management for Duke Energy and its subsidiaries. His responsibilities include managing Duke Energy and its subsidiaries' credit ratings and interactions with the major credit rating agencies, commercial banks, and the capital markets. (Tr. vol. 11,628-629.)

Mr. Newlin testified that DEP faces substantial capital needs over the next several years. DEP competes for capital in the open market and must appeal to debt and Duke Energy's equity investors to attract the capital it needs. (Id. at 630.) He stated that DEP, at all times, seeks to maintain its financial strength and flexibility, including its strong investment-grade credit ratings, ensuring reliable access to capital on reasonable terms. He testified that specific objectives that support financial strength and flexibility include: (a) maintaining at least 53 percent common equity for DEP on a financial capitalization basis; (b) ensuring timely recovery of prudently incurred costs; (c) maintaining sufficient cash flows to meet obligations; and (d) maintaining a sufficient return on equity to fairly compensate shareholders for their invested capital. (Id. at 631.)

Mr. Newlin testified that as of the date he filed his direct testimony, on October 30, 2019, DEP's outstanding debt was rated as follows:

Rating Agency	S&P	Moody's
Issuer / Corporate Credit Rating	A-	A2
Senior Secured	A	Aa3
Outlook	Negative	Stable

He testified that obligations carrying a credit rating in the "A" category are considered strong investment-grade securities subject to low credit risk for the investor. (Id. at 635.)

DEP witness Newlin testified that S&P utilizes a family rating methodology, whereby the credit rating and outlook of the parent company, Duke Energy, is applied to each of the parent's subsidiaries. He testified that S&P revised its outlook to "Negative" on May 20, 2019, citing concerns of weaker financial measures due to 2018 storms, uncertainty over growing coal ash remediation costs and recovery in the Carolinas, regulatory lag during a period of robust capital spending, and delays related to the Atlantic Coast Pipeline. He testified that S&P stated in its May 2019 Duke Energy report that the outlook could be restored to stable if Duke Energy and its subsidiaries improve financial measures in the next 12-24 months without any deterioration in the Company's business risk profile. (Id. at 636-637.)

DEP witness Newlin further testified that the Federal Tax Cuts and Job Act (TCJA) in December 2017 resulted in electric utilities, including DEP, and their holding companies losing some of the cash flow contributions from deferred taxes on an ongoing basis. (Id. at 639.) He testified that this loss of cash flow would reduce DEP's funds from operations to debt percentage (FFO/Debt). (Id. at 640.) He testified that DEP's Excess Deferred Income Taxes (EDIT) are customer supplied funds. He testified that DEP proposed to flow the property-related unprotected EDIT back to customers over a 20-year period, which would smooth out the cash flow hit DEP must take as it returns the EDIT to customers. (Id. at 645.)

On rebuttal, Mr. Newlin testified that he disagreed with Public Staff witness Hinton's recommendation to flow back unprotected EDIT over a five-year period, as the result on cash flows would be credit weakening for DEP. He testified that the five-year unprotected EDIT flowback would reduce DEP's FFO/Debt ratio (Id. at 678, 681.)

Mr. Newlin in his rebuttal disagreed with Mr. Hinton's recommendation that DEC and DEP should moderate upstream equity dividends to Duke Energy to alleviate potential credit pressures as a result of accelerated EDIT flowback. Mr. Newlin also disagreed with Mr. Hinton's testimony that Duke Energy can use funds from its $2.5 billion November 2019 common equity issuance to further decrease infusions to the parent. He testified that the equity infusion was intended to protect Duke Energy's credit in light of a range of scenarios related to the delay and regulatory uncertainty around the Atlantic Coast Pipeline. (Id. at 682-83.) He testified that DEP's senior issuer credit ratings of A2 and A- from Moody's and S&P respectively, would likely be downgraded if the utility were to lose the full debt and equity return on coal ash remediation costs. He testified this FFO/Debt metric is the primary financial measure used by the rating agencies to determine the credit quality of utility companies, including DEP. (Id. at 688.)

Upon cross examination, DEP witness Newlin agreed that Public Staff Newlin Rebuttal Cross-Examination Exhibit 1 states DEP's dividends paid to parent Duke Energy for the years 2015 through 2019. He testified the five-year average annual dividends paid were $120 million. He testified that DEP Form E-1, Item 33 d, Line 17, filed October 30, 2019, lists the dividends to be paid 2020 through 2023, which annually average $706 million, an increase of 533% compared to 2015 through 2019. (Tr. vol. 1, 74.)

Mr. Newlin testified that the DEP response to Public Staff Data Request No. 166 Item 4 is shown on Public Staff Newlin Rebuttal Cross-Examination Exhibit 2. In his direct testimony, Mr. Newlin stated that if there were a DEP downgrade from Moody's, the downgrade would be Senior Secured Aa3 rating to A1 and A2 issuer rating to an A3 issuer. Based on current historically low interest rates and near record tight credit spreads would cost DEP secured debt issuance ten basis points. (Id. at 88.) He testified that DEP was done with its 2020 bond issuances. (Id. at 91.) He testified that DEC Public Staff Data Request No. 230, Items 6 and 7 states that the DEC planned long term debt issuances and long term debt maturities for the four years, 2020 through 2023. This cross examination exhibit showed that the DEC estimated impact on cost of debt based upon a five and also 10 basis point debt cost increase, considering long term maturities and long term issuances, both would be 0.00% in 2021, 0.01% in 2022, and 0.01% in 2022. (Id. at 93-98.)

Mr. Newlin testified that the Public Staff and DEP grid deferral stipulation, if approved by the Commission, would be both quantitative and qualitative credit supporting with respect to the credit rating agencies. (Id. at 66-67.)

DEP witness Newlin further testified that DEP, with its lower Aa3 Senior Secured credit rating, compared to DEC's Aa2 Senior secured credit rating, issued $700 million in 30-year first mortgage bonds on August 20, 2020 at 2.50%. (Id. at 76-77.) Mr. Newlin testified that Duke Energy issued $2.5 billion in new stock with a forward settlement whereby the funds are to be received by December 2020. (Id. at 79.)

Mr. Newlin testified that Moody's looks at FFO to debt on a sustained basis, and Moody's does not define sustained basis. He testified that Moody's uses a FFO to debt three-year basis in its reporting, similar to what Public Staff witness Hinton did in his testimony. (Id. at 81.)

On cross examination, Mr. Newlin further testified that the credit rating agencies consider riders as credit positive. He agreed that DEP has the following annual riders: fuel adjustment, renewable energy adjustment, demand side management and energy efficiency, and competitive procurement of renewable energy. (Id. at 83-84.)

Mr. Newlin testified that the Moody's quantitative rating comprises 50% of the total credit rating, and FFO to debt comprises 15% of the total. (Id. at 86.)

DEP witness Newlin testified that Public Staff Newlin Rebuttal Cross Examination Exhibit 3 is DEP's E-1, Items 23, 33-D and 38 filed with DEP's Application. He testified that these E-1 items showed DEP's planned issuance of new debt from 2020 through 2022, totaling $2.75 billion. He testified for the years 2020 through 2022, DEP would have total debt retirements of $2.1 billion.

Mr. Newlin on cross examination testified that he accepted the Public Staff's calculation that the revenue requirement for the first year would be $100 million less with the Public Staff's recommended coal ash position when compared to DEP's. (Id. at 107.)

On cross examination, Mr. Newlin testified that he was not certain if Duke had calculated a comparison of the revenue requirement effect of Duke's position versus the Public Staff's position on coal ash. The uncontroverted Doss Spanos Riley Rebuttal Public Staff Cross-Examination Exhibit 7, prepared by Mike Maness, Director of the Public Staff's Accounting Division, showed that DEP's coal ash five-year amortization with a return compared to the Public Staff's position would increase the annual revenue requirements as follows: Year 1 - $100.4 million, Year 2 - $94.6 million, Year 3 - $88.9 million, Year 4 - $83.2 million, Year 5 - $77.5 million.

Doss Spanos Riley Rebuttal Public Staff Cross-Examination Exhibit 8 showed for the years 2020 through 2023, the ARO related coal ash revenue requirements differences compared to increased financing costs based upon the possible 10 basis point interest rate increase, if DEP's Moody's First Mortgage Bond credit rating was downgraded. This exhibit showed:

Year	(Millions) Revenue Requirement Difference	(Millions) Cumulative Interest Increase	(Millions) Revenue Requirement Reduction
2021	$100.357	$ .900	$99.457 (5)
2022	$94.638	$1.850	$92.788 (5)
2023	$88.410	$2.550	$86.366 (5)
Total			$278.611

DEP did not provide redirect testimony to contest the calculations in this cross examination exhibit.

DEP witness Newlin further testified that the debt market is good right now, as DEP in August borrowed $700 million at 2.50%. (Id. at 76.) He further testified on cross examination that the S&P Index and Nasdaq both hit all-time highs on Friday, August 21, 2020. (Id. at 113.) He further testified that Duke Energy's current dividend yield is 4.77%. (Id. at 114.)

On redirect, DEP introduced Newlin Duke Redirect Exhibit No. 3, Moody's DEP Credit Opinion dated March 30, 2020, which stated that Moody's stable outlook assumes DEP will continue to be allowed to recover the majority of its coal ash remediation spending and that DEP will be able to earn a return on the deferred balance. This Moody's report also stated that one of the factors that could lead to a DEP downgrade is a decline in the credit supportiveness of DEC's regulatory relationships in North and South Carolina, particularly with regard to coal ash remediation recovery in North Carolina. (Tr. vol. 2, 44-45.)

Upon questions from Commissioner Clodfelter, Mr. Newlin agreed that insofar as the Commission has discretion, that discretion is constrained by the North Carolina General Statutes and by decisions of the North Carolina Supreme Court. Mr. Newlin further agreed with Commissioner Clodfelter that the determination of what constitutes a capital investment for rate making purposes in North Carolina is determined from N.C.G.S. 62-133 and from case law interpreting the statute, and it is not determined by Moody's for ratemaking purposes. (Id. at 80-81.)

In response to questions from Commissioner Duffley, Mr. Newlin testified that the Commissions' DEP 2017 rate case provided 400 basis points of support for DEP's December 2019 FFO to debt metric of 22.4%. He testified that the 400 basis points, if removed, would result in FFO to debt of 18.4% He further testified in response to Commissioner Duffley's questions that if the Commission does that anything differently than the 2017 DEC and DEP rate cases regarding coal ash, that the consistency and predictabilities of regulations metric would change. (Id. at 81-94.)

In response to questions from Commissioner Brown-Bland, he testified that in the second quarter Duke Energy earnings conference call, Duke Energy stated that the FFO to debt impact on holding company Duke Energy would be roughly a hundred basis points for negative decisions at DEC and DEP, similar to the DENC rate case order. (Id. at 97.)

John Hinton, Director of the Public Staff's Economic Research Division, testified on credit metrics in support of the Public Staff's recommendation of a five-year flowback of unprotected excess deferred income taxes. He testified that as noted in Moody's March 28, 2019, DEP Credit Opinion, an FFO to debt ratio between 21% and 23% qualifies for an A rating. He testified that with the Public Staff five-year flowback, the FFO/debt metric would only be below 21% in one year 2020, and the other metrics are 22% and 24% through 2023. (Tr. vol. 15, at 326-327.) Mr. Hinton testified that Moody's rated DEP's First Mortgage Bonds and Long-Term Issuer with the second highest ratings among the other five Duke Energy electric utility subsidiaries as follows:

Rating Agency	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

(Id. at 328-329.)

Mr. Hinton testified that he believes that unexpected financial developments, such as significant reductions in the Company's cash flows or significant increases in its debt balances, would have to occur to reduce DEP's cash flow from operations or cause the Company to issue additional debt to trigger a downgrade. (Id. at 327.)

Mr. Hinton further testified that he expected regulatory lag to be effectively removed by the securitization cash payment to DEP for its storm costs of approximately $668.1 million as of January 31, 2020. (Id. at 331.)

Public Staff witness Hinton testified that Moody's places a 40% weight on financial strength as measured by its quantitative financial metric, 50% weight on the utility regulation, and 10% weight on utility diversification. The 50% weight on regulation focuses on two areas: the regulatory framework and the ability to recover costs and earn returns. He testified 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 manner in which the utility manages the political and regulatory process. He testified 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. 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. (Id. at 327.)

Public Staff witness Hinton testified that there are other sources of capital available to DEP that would not deteriorate DEP's FFO/Debt metrics. He testified that DEP's filed E-1 Item 38 stated from 2020 through 2023, DEP plans to issue a total of $3.45 billion in long term debt and infuse $2.83 billion to Duke Energy. He testified that an option may exist for DEP to offset some of DEP's debt issuances through a reduction in its planned contributions to its parent, which would better allow DEP to maintain Moody's A2 issuer credit rating. (Id. at 328.)

Mr. Hinton further testified that Duke Energy will issue 29 million shares in common stock, which will result in approximately $2.5 billion in net proceeds. He testified that this additional equity could allow DEP to decrease its projected equity infusions up to the parent company, which would alleviate DEP's need to issue the amount of new debt and reduce the possibility of a downgrade. (Id. at 329.)

Mr. Hinton testified that DEP believes that it is reasonable to expect that if there is a one-notch downgrade by Moody's to A3, it would increase the investor-required bond yield by 10 basis points. He testified that it is worth noting that Moody's A-rated long-term utility bond yields as of February 29, 2020 are 3.11%, the lowest in over thirty years. He further testified that in light of DEP's financial forecasts, it is his opinion that the added cost of debt capital from a downgrade to a senior secured A1 rating will not be burdensome on DEP and its customers. (Id. at 330.)

Mr. Hinton testified that Moody's Credit Opinions for DEP in Hinton Exhibit 3, identified that the securitization of DEP's storm costs should ameliorate some of the downward pressure on DEP's credit metrics. (Id. at 331.)

On cross examination, Mr. Hinton testified that at the time he wrote his testimony, his belief was that the EDIT issue was the most important issue in the case, and the issue of CCR recovery was not flushed out at the time. (Tr. vol. 2, 109-10.) However, he did not agree that DEP would be credit downgraded should the Commission approve the Public Staff CCR sharing recommendation. He testified that whether there would be a credit downgrade depends on a multitude of factors, including regulatory support and consistency, regulation of cost recovery methods, the original request and the actual revenue requirements approved by the Commission, and how the approved revenue requirement impacts DEP's finances, both on a cash flow basis and balance sheet basis. Witness Hinton noted that Ms. Shoemaker, Senior Credit Analyst with Moody's, was concerned about the Commission's treatment of coal ash costs; but, witness Hinton noted that it all gets back to dollars to the Company, and Moody's considers the totality of the rate case. (Id. at 110, 113-14, 116.)

Mr. Hinton testified that the Public Staff does not believe DEP's coal ash management was prudent, and the Public Staff believes in the sharing concept. Mr. Hinton testified that Moody's stated that DEP's stable outlook assumes DEP will continue to be allowed to recover the majority of their coal ash remediation spending. He testified that majority is the issue there. (Id. at 114.) He testified that DEP has cash flows or other resources of capital available, so DEP does not necessarily have to increase debt. (Id. at 117.)

On redirect, Mr. Hinton testified that throughout the Moody's credit opinions, Moody states there could be a downgrade, not that there would be a downgrade. (Id. at 118.) He testified that the credit rating agencies would consider favorably the grid deferral for DEC and DEP of $1.3 billion as acceleration of capital spending recovery, and the stipulation 52% equity and the 9.6% return on common equity as credit positive. (Id. at 118-120.)

Steven Young, the Executive Vice President and Chief Financial Officer of Duke Energy, testified on rebuttal that to fund the significant capital investments required to provide electric service and to provide effective service to the public, DEP must be able to attract debt capital, and Duke Energy must be able to attract equity capital in the same financial markets utilized by their peers and by other non-regulated businesses. He testified that if access to the capital markets is unduly impaired, DEP's ability to provide customers with safe and reliable electric service at reasonable cost is jeopardized. (Tr. vol. 11, 704.)

Mr. Young testified that neither Duke Energy nor DEP have access to any established "reserves" to pay the carrying costs of their unavoidable need to incur debt (and equity) 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. (Id. at 705.)

DEP witness Young testified 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 707.)

Witness Young testified in the recent DENC rate case order, the Commission disallowed recovery of a significant portion of the financing costs associated with coal ash basin closure. He testified that disallowances of the recovery of these costs in DEP's case would decrease DEP's cash-flow from operations and increase funding requirements from debt and equity investors, as these costs are unavoidable and will continue to be incurred. He testified that this would impair the credit quality of DEP and ultimately drive up financing costs and customer rates. (Id. at 710.)

On cross examination, DEP witness Young agreed that N.C.G.S. 62-133(a) states that in fixing rates for any public utility, the Commission shall fix such rates as shall be both fair to the public utilities and to the consumer. (Tr. vol. 3, 42.)

Mr. Young further testified that he agreed that in N.C.G.S. 62-133 (b) (4), which is the section on the rate of return, one of the items that the Commission should do is to set a rate of return so that the utility could compete in the market for capital funds on terms that are reasonable and that are fair to its customers and to its existing investors. He further testified that language does not mean that the Commission has to set rates and make decisions so that a company has one of the highest credit ratings in existence for public utilities. (Id. at 42.)

Witness Young further testified that the $1.3 billion grid deferral in the stipulation with the Public Staff does not make much difference in cash flow. He testified that the grid deferral makes a big difference in the earnings world and the GAAP earnings world, and that Duke Energy's investors are interested in that in a big way. He further testified that storm cost securitization is going to help DEP recover its storm costs quicker, once DEP issues the bonds. He testified that securitization is a useful tool and a good piece of legislation. (Id. at 50.)

Mr. Young testified that Docket No. E-2, Sub 1219 Hevert Rebuttal Exhibit RBH-14, page 1, contained credit ratings of 31 electric holding companies. He agreed that Duke Energy had an A1 S&P issuer rating, and of the 31 companies, Duke Energy is the second highest company on the list, with only one other company having a higher rating. (Id. at 51.)

Mr. Young testified that DEC Docket No. E-7, Sub 1214 DEC Hevert Rebuttal Exhibit 14, pages 1 and 2 listed Moody's long-term issuer credit ratings for electric holding and 77 electric operating utilities. He testified that DEP is one of only eleven Moody's A2 rated. He testified that DEP's credit rating is in the top 20% of the 77 electric utilities on this list. (Id. at 54.)

Mr. Young testified that recently DEP borrowed $700 million at 2.50% (Id. at 59) and that DEP's 2020 borrowing is essentially done. (Id. at 60) Mr. Young testified that DEP and all of Duke Energy's other operating utilities are cash flow negative and will be in the debt markets each year. (Id. at 61.)

Mr. Young further testified that one of the reasons Duke Energy's stock traded at a discount relative to other electric holding companies is the Atlantic Coast Pipeline. He testified that there remains a discount, and what is sitting in front of Duke Energy is the regulatory regime, particularly in the Carolinas, and particularly around coal ash. (Id. at 63.)

DEP witness Young testified that DEP's E-1 Item 38 showed the DEP long term debt amounts to be borrowed in 2021 at $900 million and in 2022 at $950 million. He testified that DEP's data request response showed that if DEP received a first mortgage bond credit downgrade, it would add ten basis points to DEP's future long term debt issuances. He testified that the ten basis points would add

$900,000 annual interest to the $900 million debt issuance in 2021, and $950,000 annual interest to the $950 million debt issuance in 2022. (Id. at 68.)

Mr. Young testified that Public Staff Young Rebuttal Exhibit Number 1 is the Duke Energy Earnings Review and Business Update, Fourth Quarter 2019. He agreed this document stated that Duke Energy is delivering on the financial results 2019 earnings per share above the guidance range midpoint, and also it stated that strong year-over-year results represent 7% growth. He testified that this document stated that Duke Energy has very strong earnings per share growth, with 7% growth from 2018 to 2019. He testified that the exhibit shows that Duke Energy serves three of the five most vibrant states with Florida one, North Carolina four, and South Carolina five, which are all credit positive. He testified that Duke Energy is not expected to be a significant taxpayer until 2027, which will help the cash flows. Mr. Young testified that this Duke Energy document stated that Duke Energy's Total Shareholder Return is an attractive risk adjusted 8% to 10%, which he believes to be a very adequate and attractive total shareholder return. He testified that Duke Energy has a top quartile dividend yield and provides low risk returns. (Id. at 73-80.) He testified that Duke Energy's dividend yield as of August 21, 2020, was 4.77%, and Duke Energy on July 6, 2020 announced a two-percent increase in its dividend rate. (Id. at 43.)

Mr. Young also testified that this Fourth Quarter 2019 earnings document stated DEP has $791 million available under the Duke Energy master credit facility. (Id. at 81.)

DEP witness Young testified that the UBS Midwest Virtual Conference, August 20, 2020, for Duke Energy with Duke Energy presenters Steve Young and Bryan Buckler, stated that as to this North Carolina rate case, the favorable settlements with a broad group of intervenors highlight the constructive regulatory environment in North Carolina. He testified that he believes settlements are constructive as do all their lenders, debt, equity, and credit rating agencies. He testified the document cited the following key settlement issues: 9.6% return on equity, 52% equity capital structure, the deferral treatment of the $1.3 billion grid improvement projects, and the flowback of the unprotected EDIT over five years. (Id. at 81-83.)

Mr. Young further testified that Duke Energy was highly confident in achieving a $350 million to $450 million reduction in O&M and other expenses to mitigate the 2020 headwinds. He also testified that Duke Energy plans to settle its $2.5 billion equity issuance in 2020. (Id. at 84.)

In response to questions from Commissioner Brown-Bland, Mr. Young testified that Duke Energy stock was trading at no discount at the end of 2018. He testified during 2019, the following events occurred: the DEQ order for full excavation of all coal ash ponds and the events for the Atlantic Coast Pipeline in the U.S. Fourth Circuit, which were negative. He testified that there was a stock pricing drop in early 2020, when the DENC North Carolina on coal ash was issued. (Tr. vol. 4, 23-24.)

In response to questions from Commissioner Clodfelter, witness Young testified that DEP has sufficient information to make a showing in this case that the ongoing expenditure for coal ash remediation and coal ash closure are sufficiently known and measureable so that these costs could be normalized and included in base rates. (Id. at 28-29.)

In response to questions from Commissioner Duffley, DEP witness Young testified that he agreed with Moody's statement in its March 30, 2020, DEP credit opinion that in 2020 the anticipated environmental spending, inclusive of coal ash remediation to be $450 million before subsiding to an annual rate of about $200 million in 2021 and beyond. He testified that based upon DEP's settlement with DEQ, coal ash expenditures are going to be more known and measurable going forward. (Id. at 31.)

In response to questions from Commissioner McKissick, Mr. Young testified that in North Carolina, Duke Energy in today's dollars believes $8.5 billion to be the total costs to comply with the settlement with DEQ to excavate roughly 75-80 percent of the coal ash basins and then cap in place the rest. He further testified that for coal ash remediation, a run rate could be a useful tool, and a rider mechanism could be an extremely useful tool as well. He also testified that other electric utilities that have credit ratings a notch lower than DEC and DEP are operating and can compete for capital. (Id. at 38-40.)

DEP witness Steven Fetter testified on rebuttal that DEP's issuer credit ratings span between the mid-level A2, stable outlook at Moody's and the lowest level A-, stable outlook at S&P. He testified that a regulated utility should endeavor to hold ratings no lower than Baa1 (Moody's)/BBB+ (S&P), with a longer term goal of moving into or maintaining the A category. (Tr. vol. 19, 51.)

Mr. Fetter testified that the most important qualitative factors are regulation, management and business strategy, and 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.)

Mr. 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.)

Mr. 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.)

On cross examination, Mr. Fetter testified that DEP has a Moody's credit rating of Aa3 senior secured, and an unsecured issuer rating of A2 and stable. He testified that if DEP was downgraded one grade, its Moody's issuer rating would be A3, and its Moody's secured rating would be A1, both still in the A range. (Id. at 81.) He testified that Duke Energy has a Moody's issuer unsecured rating of Baa1, which is two grades lower than DEP. Doss Spanos Riley Rebuttal Public Staff

Cross-Examination Exhibit 4, the DEP E-1 Item 34 A listed the DEP outstanding long-term debt updated as of February 29, 2020, showed that First Mortgage Bonds were 86.7% of DEP's long-term debt.

Mr. Fetter testified on cross examination that DEP has a Moody's senior secured rating of Aa3, one notch below DEC. He testified that the DEC and DEP stipulation with the Public Staff stipulated that DEC's May 31, 2020, embedded cost rate of debt was 4.27%, and DEP's was 4.05%, 22 basis points lower. (Id. at 100-102.)

Mr. Fetter testified that nowhere in N.C.G.S 62-133 does it state that rates have to be set to avoid a credit downgrade, or that rates have to be set to increase the stock price of utilities, or maintain stock prices of utilities. (Id. at 106-107.)

Mr. Fetter testified that each of the DEP Commission-approved riders are considered by credit rating agencies as credit positive. (Id. at 86, 87.) He testified that the DEP and Public Staff stipulation, including the grid deferral component, would be viewed positively by the credit rating agencies. He testified that the coal ash decision was a big issue. (Id. at 87.) Mr. Fetter testified that storm cost securitizations are credit positive. (Id. at 88-89.)

Mr. Fetter testified that credit rating agencies give great deference to decision making made by a utility with regard to a settlement. He testified that this would include the stipulated 9.6% ROE, the 52% equity capital structure, and the five year flowback for unprotected EDIT. (Id. at 110.)

Mr. Fetter testified that Public Staff Fetter Rebuttal Public Staff Cross Examination Exhibit Number 2 showed the stock price close for Duke Energy compared to the S&P 500 Index from February 24, 2020, the date of the Commission's DENC general rate case order, and March 3, 2020. He testified that this exhibit showed a drop to March 3, 2020, in the Duke Energy stock price of 6.54%, compared to a drop in the S&P Index of 6.91%. Mr. Fetter testified that he had also been provided the Dow Public Utilities Index for the same period, and the drop was 6.27%. (Id. at 92-93.) DEP witness Fatter further testified on cross examination that the Value Line August 14, 2020, evaluation for Duke Energy does not mention coal ash. (Id. at 94.)

Mr. Fetter testified that Fetter Rebuttal Public Staff Cross Examination Exhibit 1, DEP Rebuttal Exhibit RBH -15, was a list of credit ratings for electric holding and electric operating utilities. He testified that DEP's A2 issuer rating was one of only 11 operating companies that are rated A2, and that five operating companies are rated A1. He testified that of the 78 operating companies listed, DEP was in the top 21%. (Id. at 79, 80.)

Mr. Fetter further testified that Fetter Rebuttal Public Staff Cross Examination Exhibit 3, which is the Duke Energy Investor Update September 2020, listed many credit positive actions by Duke Energy including, but not limited to: strong regulated growth outlook, delivering on annual earnings guidance, earned at or above allowed ROEs on a consistent basis, and that Duke Energy was highly confident in achieving $350 - $450 million reduction in O&M and other expenses to mitigate 2020 headwinds. (Id. at 96-103.)

Mr. Fetter further testified on cross examination that Fetter Rebuttal Cross Examination Exhibit 4, which was an article by B of A Securities dated September 9, 2020, upgrading to a buy recommendation the stock of Duke Energy, although B of A Securities perceived a North Carolina coal ash order similar to Dominion as quite likely. (Id. at 107-108.) He testified this article states B of A Securities continues to expect Duke Energy's rate cases in the Carolinas to have a similar outcome to Dominion's coal ash order with a ten-year amortization period and no return once past the deferral. (Id. at 109-110.) Mr. Fetter testified that Fetter Rebuttal Public Staff Cross Examination Exhibit 5, which was a follow up B of A Securities article dated September 11, 2020, reaffirmed that B of A Securities expected the DEP order to be the same as the Dominion order, and reaffirmed the B of A Securities Duke Energy buy recommendation. (Id. at 110-111.)

Mr. Fetter further testified on cross examination that Duke Energy's stock price opened on September 9, 20202, at $82.42, and closed on September 11, 2020, at $83.03, which was up about 0.7 percent during these three market trading days and after the two B of A Securities reports. (Id. at 112.)

He testified that he accepted that on October 5, 2020, the date of his verbal rebuttal testimony, at 12:10 p.m., Duke Energy's stock price was $91.84, an 11.2% increase from the close of $82.59 on September 9, 2020. (Id. at 112, 114-115.)

On redirect, DEP witness Fetter testified that utility securitization legislation across the United States has been supported by the full spectrum of interested stakeholders, from utility, to intervenors, to the consumer side. (Id. at 119.) He further testified that he reviewed Public Staff late-filed Exhibit Number 1 in the DEC rate case that related to the culpability issue raised in that case. He testified that what concerns him is that, rather than creating a standard that investors could look at and understand, this document says the culpability standard would be fact and case specific, and that is not amenable to a bright line test requested by Commissioner McKissick. (Id. at 120.)

Conclusion

N.C.G.S. 62-133 sets forth the factors to be considered by the Commission in setting rates for public utilities. N.C.G.S. 62-133 (a) states:

> In fixing rates for any public utility subject to the provisions of this Chapter, other than bus companies, motor carriers, and certain water and sewer utilities, 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 (d) further states that "[t]he Commission shall consider all other material facts of records that will enable it to determine what are reasonable and just rates."

There is no requirement in N.C.G.S. 62-133 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 record shows DEP's current outstanding debt is rated in the "A" category, which is considered strong investment-grade, representing a lower credit risk to the investor. DEP seeks to maintain financial strength and flexibility to ensure reliable access to capital on reasonable terms and the evidence indicates it has historically done so.

The Commission has weighed the totality of the evidence in the record and concludes the rates established in this order are consistent with this principle. The record contains extensive evidence discussing the relevance and importance of credit ratings, cash flow, stock price, and earnings per share in the management of a utility company. The record contains various expert witness opinions regarding the likelihood of a credit downgrade and the impact of such a credit downgrade on the cost of debt. However, the possibility the Commission's decision may trigger a credit downgrade is a merely that – a possibility and not a certainty. Credit downgrades depend on a multitude of factors, including general regulatory support and consistency, cost recovery methodology, timely recovery of costs, original requested/actual approved revenue requirement, and revenue requirement impact on both cash flow and the balance sheet. The confluence of this multitude of factors following the Commission's order in this case is speculative.

Even if a downgrade were a certainty, the Commission must render a decision based on N.C.G.S. 62-133 and evaluate the ultimate impact on customers and the ability of the utility to access capital markets. The evidence in the record does not show that Duke Energy or its subsidiaries would be unable to access capital markets on reasonable terms following a credit downgrade. The evidence further shows that a credit downgrade would likely result in the cost of debt rising 10 basis points, resulting in a relatively minor impact on rates.

The Commission also concludes from the record that DEP has sufficient levers to use to manage its cash flow going forward to support its credit rating and cash flow metrics by reducing expenses, reducing capital spend, additional equity injection by Duke Energy, and reduced dividend payments up to Duke Energy.

The Commission does not believe it is appropriate to decide individual or collective issues in a general rate case with the goal of achieving a specific credit rating, stock price range, cash flow or similar metric. It is the responsibility of the Commission to decide general rate cases pursuant to N.C.G.S. 62-133 and the decisions of the North Carolina Supreme Court. The Commission decides a variety of individual issues that impact revenue requirement, including the rate base, the rate of return, the capital structure, depreciation, the pro forma revenue levels under current rates, and the reasonable operating expenses. It is the responsibility of the utility's management, to prudently manage the utility in a manner that supports the utility's credit ratings and the stock price.

The Commission has decided the issues in this proceeding based upon the requirements of N.C.G.S. 62-133. The rates fixed by this order 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.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 29-37

[Revenue Requirement]

The evidence for these findings and conclusions is contained in the first and second Partial Stipulations, DEP's verified Application and E-1, the testimony and exhibits of the witnesses, 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 Stipulating Parties have agreed upon; the revenue requirement effects of the agreed-upon issues are set out in detail in Smith Second Settlement Exhibit 3, Maness Stipulation Exhibit 1, Schedule 1, and Maness Second Stipulation Exhibit 1, Schedule 1 (the Partial Stipulation Revenue Requirement Exhibits), and Public Staff witness Maness' Supplemental Testimony Supporting Second Partial Stipulation.

Smith Second Settlement Exhibit 2 shows DEP's revised requested increase incorporating the provisions of the Second Partial Stipulation and the Company's position on the Unresolved Issues. The resulting proposed increase in the base revenue requirement of the Company is $408,933,000. Maness Second Stipulation Exhibit 1 shows the Public Staff's revised recommended change in revenue requirement incorporating the provisions of the Second Partial Stipulation, adjustments related to the audit of the May 2020 update, and a number of adjustments reflecting the Public Staff's position on the Unresolved Issues. The resulting proposed increase in the base revenue requirement by the Public Staff is $264,978,000, which includes the settled positions of the Company and the Public Staff as well as the unsettled positions of the Public Staff.

Maness Second Stipulation Exhibit 1, Schedules 2 and 3 provide for the following amounts of test year pro forma operating revenues, operating revenue deductions, and original cost rate base under present rates: $3,355,753,000 of operating revenues, $2,824,618,000 of operating revenue deductions, and $10,563,824,000 of original cost rate base; and under the Public Staff's proposed rates: $3,620,731,000 of operating revenues, $2,886,657,000 of operating revenue deductions, and $10,587,216,000 of original cost rate base. Maness Second Stipulation Exhibit 1 contains a verified and detailed breakdown of these amounts, including the pro forma lead lag impact of the adjustments.

As discussed in the body of this Order, the Commission approved the Partial Stipulations in their entirety and makes its individual rulings on the unresolved issues as previously discussed. After giving effect to the approved Partial Stipulations and the Commission's decision on contested issues, an annual base non-fuel revenue increase of $264,978,000 will allow the Company a reasonable opportunity to earn the rate of return on rate base the Commission has found just and reasonable, and finds and concludes that this increase in the level of base rates to be paid by DEP's North Carolina retail customers, resulting in an overall rate of return of 6.9336% on jurisdictional rate base and a rate of return on equity of 9.60% using a capital structure of 48% long-term debt and 52% members' equity, is just and reasonable to all parties in light of all the evidence presented.

Further, the Commission finds and concludes that the following amounts of operating revenues (including an annual base non-fuel revenue increase of $264,978,000), operating revenue deductions, and original cost rate base calculated on Maness Second Stipulation Exhibit 1, Schedules 2 and 3 are appropriate and reasonable for purposes of setting rates in this proceeding:

$3,620,731,000 of operating revenues, $2,886,657,000 of operating revenue deductions, and $10,587,216,000 of original cost rate base. The Commission, therefore, also finds and concludes that for the present case, the agreed-upon accounting adjustments and the Public Staff's adjustments on the unsettled issues between DEP and the Public Staff, outlined in the Second Stipulation Exhibits of Public Staff witness Maness, are just and reasonable to all parties in light of all the evidence presented and should be approved.

Maness Second Stipulation Exhibit 1, Schedule 1 provides that the Federal unprotected EDIT amount to be refunded to ratepayers through a levelized rider for a 5 year period is $94,415,000 per year, to be adjusted by the Company once the actual amount of EDIT refunded to ratepayers through interim rates has been calculated by the Company. The State EDIT and Federal provisional amounts to be refunded to ratepayers through a levelized rider for a two year period is $71,708,000 per year. The regulatory asset/liability rider to be refunded to ratepayers through a levelized rider for a one year period is $2,091,000. The decrement riders reduce the total revenue increase for year 1 to $96,764,000, the total revenue increase for year 2 to $98,855,000, and the total revenue increase for years 3 through 5 to $170,563,000. The revenue increases should be updated based upon the actual Federal unprotected EDIT refunded to ratepayers through interim rates.

Due to the need to recalculate the actual Federal unprotected EDIT to return to ratepayers through the rider, the Commission requests that DEP recalculate the required annual revenue requirement in the same format as Maness Second

Stipulation Exhibits 1 and 2, as consistent with all of the Commission's findings and rulings herein, within 10 days of the issuance of this Order. The Commission further orders that DEP 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.

ISSUED BY ORDER OF THE COMMISSION.

This the ____ day of __________________, 2020.

NORTH CAROLINA UTILITIES COMMISSION

Kimberley A. Campbell, Chief Clerk