STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-22, SUB 532

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Virginia Electric & Power Company, d/b/a Dominion North Carolina Power, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	)	ORDER APPROVING RATE INCREASE AND COST DEFERRALS AND REVISING PJM REGULATORY CONDITIONS

HEARD: Wednesday, August 17, 2016, at 7:00 p.m., Halifax County Historic Courthouse, 10 N. King Street, Halifax, North Carolina

Tuesday, September 13, 2016, at 7:00 p.m., Pasquotank County Courthouse, 206 E. Main Street, Courtroom C, Elizabeth City, North Carolina

Wednesday, September 14, 2016, at 7:00 p.m., Commissioner's Meeting Room, Dare County Administration Building, 954 Marshall Collins Drive, Manteo, North Carolina

Wednesday, September 21, 2016, at 7:00 p.m., Martin County Courthouse, 305 E. Main Street, Williamston, North Carolina

Tuesday and Wednesday, October 4 and 5, 2016, at 9:30 a.m., Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman Edward S. Finley, Jr., Presiding; Commissioners Bryan E. Beatty, ToNola D. Brown-Bland, Don M. Bailey, Jerry C. Dockham, James G. Patterson, and Lyons Gray

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BY THE COMMISSION: On March 1, 2016, pursuant to Commission Rule R1-17(a), Virginia Electric and Power Company (VEPCO), d/b/a in North Carolina as Dominion North Carolina Power (DNCP or the Company), filed notice of its intent to file a general rate case application. On the same date, DNCP filed a letter informing the Commission of the Company's intention to propose accounting adjustments to include an appropriate level of amortization of deferred post-in-service costs associated with the Company's Warren County Power Station (Warren County CC) in its rate case revenue requirement.

On March 4, 2016, DNCP filed a Response in Opposition to a motion filed on February 25, 2016, by Nucor in Docket No. E-22, Sub 479, to impose on DNCP additional jurisdictional allocation study filing requirements. On March 7, 2016, CIGFUR I filed a letter stating its position on Nucor's February 25, 2016 motion. On March 17, 2016, the Commission issued an Order denying Nucor's motion and granting alternative relief. In compliance with Paragraph 4 of the Commission's March 17, 2016 Order, DNCP filed a Single CP Cost of Service Study on May 31, 2016.

On March 31, 2016, the Company filed its Application for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina (Application), along with a Rate Case Information Report Commission Form E-1 (Form E-1),[1] and the direct testimony and exhibits of J. Kevin Curtis, Vice President - Technical Solutions; Mark D. Mitchell, Vice President – Generation Construction; James R. Chapman, Senior Vice President - Mergers & Acquisitions and Treasurer; Robert B. Hevert, Managing Partner of Sussex Economic Advisors, LLC; Paul M. McLeod, Regulatory Advisor - Regulatory Accounting Group; Bruce E. Petrie, Manager - Generation System Planning; Michael S. Hupp, Jr., Director - Power Generation Regulated Operations; Glenn A. Pierce,[2] Manager – Regulation; and Paul B. Haynes, Director - Regulation. The Company also filed requests for authority to use certain deferred accounts to implement a levelization methodology for its nuclear unit and refueling

[1] An erratum to DNCP's Form E-1 was filed on July 13, 2016, redacting confidential information from the original.

[2] Witness Pierce's direct testimony was subsequently adopted by witness Haynes.

maintenance outage expenses, as well as relief from the conditions imposed by the Commission in its April 19, 2005 Order approving DNCP's integration into PJM Interconnection, Inc. (PJM), in Docket No. E-22, Sub 418 (PJM Order).

Petitions to intervene were filed by CIGFUR I on March 7, 2016, Nucor on April 4, 2016, NCSEA on April 5, 2016, and CUCA on August 1, 2016. Notice of intervention was filed by the Attorney General on June 13, 2016.

The Commission subsequently entered Orders granting the petitions to intervene of CIGFUR I, NCSEA, Nucor, and CUCA. The Public Staff's intervention is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19. The Attorney General's intervention is recognized pursuant to G.S. 62-20.

On April 20, 2016, Nucor filed a motion requesting *pro hac vice* admission before the Commission for Damon E. Xenopoulos. On June 3, 2016, DNCP filed a motion requesting *pro hac vice* admission before the Commission for Joseph K. Reid, III. Orders allowing these motions for limited practice before the Commission were issued on April 26, 2016, and June 7, 2016, respectively.

On April 26, 2016, the Commission issued an Order Establishing General Rate Case and Suspending Rates. On May 10, 2016, the Commission issued an Order Scheduling Hearings and Requiring Public Notice.

On May 2, 2016, DNCP filed an Application for an Accounting Order to Defer Certain Capital and Operating Costs Associated with Brunswick County Power Station Addition in Docket No. E-22, Sub 533. On May 3, 2016, the Company filed a Motion for Reconsideration of the Commission's March 29, 2016 Order Denying Deferral Accounting for Warren County Combined Cycle Generating Facility in Docket No. E-22, Sub 519.

On May 17, 2016, the Commission issued an Order Consolidating Dockets, which consolidated this general rate case with DNCP's pending petition for deferral accounting authority to defer post-in-service costs associated with commercial operation of the Brunswick County Power Station (Brunswick County CC) in Docket No. E-22, Sub 533, and the Company's motion for reconsideration in Docket No. E-22, Sub 519, of the Commission's Order denying the Company's request to defer post-in-service costs associated with commercial operation of the Warren County CC.

On July 8, 2016, DNCP submitted a supplemental filing pertaining to the Company's request for relief from the conditions imposed by the PJM Order, supported by the supplemental direct testimony of Michael S. Hupp, Jr. and James R. Bailey, Manager – Planning and Strategic Initiatives – Electric Transmission Department.

On August 12, 2016, DNCP filed the supplemental direct testimony and exhibits of James R. Chapman, Deanna R. Kesler, Regulatory Consultant in Demand Side Planning – Integrated Resource Planning, Bruce E. Petrie, Paul M. McLeod, and Paul B. Haynes, as well as applicable updated NCUC Form E-1 information report items.

On September 7, 2016, the Public Staff filed the direct testimony and exhibits of Jack L. Floyd, Engineer, Electric Division; John R. Hinton, Director, Economic Research Division; Michael C. Maness, Assistant Director, Accounting Division; James S. McLawhorn, Director, Electric Division; Jay B. Lucas, Engineer, Electric Division; Dustin R. Metz, Engineer, Electric Division; Katherine A. Fernald, Assistant Director, Accounting Division; and Darlene P. Peedin, Supervisor, Electric Section, Accounting Division. On the same day, Nucor filed the direct testimony of J. Randall Woolridge, Professor of Finance and University Fellow at Pennsylvania State University; Lane Kollen, Vice President and Principal, Kennedy and Associates; Jacob M. Thomas, Senior Project Manager, GDS Associates, Inc.; and witness Dennis W. Goins, Economic Consultant, Potomac Management Group.

On September 7, 2016, CUCA filed a motion requesting a one-day extension of time for it and the other intervenors to file their testimony and exhibits. The Commission issued an Order allowing CUCA's motion on September 8, 2016.

On September 8, 2016, CUCA filed the direct testimony of Kevin O'Donnell, President of Nova Energy Consultants, Inc.; CIGFUR I filed the direct testimony of Nicholas Phillips, Jr., Managing Principal, Brubaker & Associates, Inc.; and Nucor filed the supplemental direct testimony of witness Goins.

On September 26, 2016, DNCP filed the rebuttal testimony and exhibits of J. Kevin Curtis, Mark D. Mitchell, James R. Chapman, Robert B. Hevert, Paul M. McLeod, Mark C. Stevens, Director of Regulatory Accounting, James I. Warren, member of the law firm of Miller & Chevalier Chartered, Michael S. Hupp, Jr., and Paul B. Haynes.

On September 28, 2016, DNCP filed a list of witnesses, the order of witnesses, and estimated time for cross-examination of the witnesses.

On October 3, 2016, the Public Staff filed a notice of settlement in principle. In addition, the Public Staff filed a motion to delay the hearing of expert testimony. The Public Staff requested that the Commission convene the hearing as scheduled on October 4, 2016, at 9:30 a.m., to receive public witness testimony, but delay the start of the testimony by expert witnesses until 1:30 p.m. that afternoon.

Also, on October 3, 2016, DNCP, the Public Staff, and CIGFUR I (Stipulating Parties) entered into and filed an Agreement and Stipulation of Settlement (Stipulation). In addition, DNCP and the Public Staff filed a joint motion to excuse witnesses.

In support of the Stipulation, on October 3, 2016, DNCP filed the testimony and exhibits of J. Kevin Curtis, Robert B. Hevert, and Paul B. Haynes, and the joint testimony of Mark C. Stevens and Paul M. McLeod; and the Public Staff filed the testimony and exhibits of Katherine A. Fernald and John R. Hinton.

On October 4, 2016, Nucor filed a motion to postpone the hearing of expert testimony for 14 calendar days following the filing of the final version of the Stipulation and the additional expert witness testimony, if any. In summary, Nucor asserted that it needed additional time to prepare for the hearing due to the Stipulation recently filed by DNCP, the Public Staff and CIGFUR I.

The public hearings were held as scheduled. The following public witnesses appeared and testified:

Halifax:	Belinda Joyner, Tony Burnette, Larry Abram, Dean Knight, Janice Bellamy, Regina Moffett, and Betty Bennett
Elizabeth City:	Peter Bishop
Manteo:	Robert Woodard, Walter L. Overman, Dwight Wheless, Robert C. Edwards, Manny Medeiros, and Judy Williams
Williamston:	Martha McDonald, John McDonald, Tawilda Bryant, Rhett B. White, Ronnie Smith, John Liddick, Linda Gibson, Samantha Komar, Louise Simmons, Jerry McCrary, Glenda Barnes, and Reginald Williams, Jr.
Raleigh:	No public witnesses appeared.

On October 3, 2016, DNCP filed a Motion for Approval of Undertaking and Notice to Implement Temporary Rates, Subject to Refund, pursuant to G.S. 62-135.

The matter came on for hearing on October 4, 2016, at 9:30 a.m. After determining that there were no public witnesses who desired to testify, the Chairman heard the parties' arguments on the Public Staff's motion to delay the start of the expert witness testimony until 1:30 p.m. that afternoon, and Nucor's motion to postpone the hearing for 14 calendar days. The Chairman ruled that the hearing of expert testimony would commence at 1:30 p.m., on October 4, 2016. Further, the Chairman ruled that the concerns of Nucor and other parties about needing more time to prepare direct testimony and cross-examination regarding the Stipulation would be addressed by rearranging the order of witnesses and other accommodations, if such accommodations became reasonably necessary during the hearing. Thus, the Public Staff's motion was granted, and Nucor's motion was denied, but Nucor's and the other parties' concerns about needing additional time to prepare were resolved.

The expert witness hearing began at 1:30 p.m., on October 4, 2016, and was concluded on October 5, 2016. DNCP presented the testimony of witnesses Curtis, Chapman, Mitchell, Hevert, McLeod, Stevens, Warren, Hupp, and Haynes. The testimony and exhibits of DNCP witnesses Kesler, Bailey, and Petrie were stipulated into the record. Nucor presented the testimony of witness Woolridge. The testimony and exhibits of Nucor witnesses Kollen, Thomas, and Goins were stipulated into the record. CUCA presented the testimony of witness O’Donnell. The testimony of witness Phillips was withdrawn by CIGFUR I.

The Public Staff presented the testimony of witnesses Maness, Fernald, Floyd, and McLawhorn. The testimony and exhibits of Public Staff witnesses Lucas, Peedin, Metz, and Hinton were stipulated into the record.

The pre-filed testimony of those witnesses who testified at the expert witness hearing, as well as all other witnesses filing testimony in this docket, except for CIGFUR I witness Nicholas Phillips, Jr., was copied into the record as if given orally from the stand, and their pre-filed exhibits were admitted into evidence.

On October 11, 2016, the Commission issued a notice of mailing of transcript and ordered that the parties submit briefs and/or proposed orders by November 10, 2016. On November 4, 2016, the Attorney General moved that the date by which briefs and proposed orders must be filed be extended until November 15, 2016. The motion was granted by Order issued November 8, 2016. On November 15, 2016, the Attorney General requested a second extension to November 16, 2016. The motion was granted on November 15, 2016.

On October 12, 2016, the Commission issued an Order Approving Financial Undertaking and an Order Approving Public Notice of Temporary Rates in response to DNCP's Motion for Approval of Undertaking and Notice to Implement Temporary Rates, Subject to Refund.

On October 18, 2016, in response to a request by the Commission during the hearing, DNCP filed additional information regarding its weatherization and other energy assistance programs.

On November 15, 2016, DNCP and the Public Staff filed a late-filed exhibit, as requested by the Commission, comparing the regulatory conditions in the PJM Order with the commitments made by DNCP in the present docket.

Also on November 15, 2016, NCSEA filed a post-hearing Brief.

On November 16, 2016, CUCA filed its Proposed Findings and Brief, and Nucor and the Attorney General's Office filed post-hearing Briefs. In addition, DNCP, the Public Staff and CIGFUR I filed a Joint Proposed Order.

On December 2, 2016, the Public Staff filed a letter on behalf of the Stipulating Parties requesting that the Commission accept revisions to two paragraphs of their Joint Proposed Order regarding Nucor's motion to postpone the expert witness hearing for 14 calendar days.

On December 9, 2016, DNCP filed for informational purposes a letter of December 8, 2016, from DNCP to Nucor regarding the continuation of services to Nucor under the parties' existing contract and Schedule NS.

On December 13, 2016, DNCP and NCSEA filed a letter informing the Commission of an agreement reached between them regarding DNCP's time-of-use rate offerings.

Based upon consideration of the pleadings, testimony, and exhibits received into evidence at the hearings, the Stipulation, and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

Jurisdiction

1. Virginia Electric and Power Company (VEPCO) is duly organized as a public utility operating under the laws of the State of North Carolina as Dominion North Carolina Power (DNCP or Company) and is subject to the jurisdiction of the North Carolina Utilities Commission. DNCP is engaged in the business of generating, transmitting, distributing, and selling electric power and energy to the public in North Carolina for compensation. DNCP is an unincorporated division of VEPCO and has its office and principal place of business in Richmond, Virginia. VEPCO is a wholly owned subsidiary of Dominion Resources, Inc. (DRI).

2. The Commission has jurisdiction over the rates and charges, rate schedules, classifications, and practices of public utilities operating in North Carolina, including DNCP, under Chapter 62 of the General Statutes of North Carolina.

3. DNCP is lawfully before the Commission based upon its application for a general increase in its retail rates pursuant to G.S. 62-133, 62-133.2, 62-134, and 62-135 and Commission Rule R1-17.

4. The appropriate test period for use in this proceeding is the 12 months ended December 31, 2015, adjusted for certain known changes in revenue, expenses, and rate base through June 30, 2016.

The Application

5. In summary, by its general rate case Application, supporting testimony and exhibits filed on March 31, 2016, in this docket, DNCP sought an increase in its non-fuel base rates and charges to its North Carolina retail customers of $51,073,000, along with other relief, including cost deferrals and changes to its rate design and regulatory conditions. The Application was based upon a requested rate of return on common equity (ROE) of 10.50%, an embedded long-term debt cost of 4.889%, and DNCP’s actual capital structure of 53.36% common equity and 46.64% long-term debt, as of December 31, 2015.

The Stipulation

6. On October 3, 2016, the Public Staff filed a Notice of Settlement in Principle with DNCP and CIGFUR I. On October 3, 2016, the Stipulating Parties entered into and filed the Stipulation resolving all of the issues in this proceeding among the Stipulating Parties.

7. After carefully reviewing the Stipulation, the Commission finds that the Stipulation is the product of give-and-take in settlement negotiations among the Stipulating Parties, and is material evidence entitled to be given appropriate weight by the Commission.

Revenue Requirement and Adjustments to Cost of Service

8. The Stipulation, as reflected on Settlement Exhibits I and II, provides for a stipulated increase in the revenue requirement of $25,790,000, consisting of an increase of $34,732,000 in non-fuel revenues and a decrease of $8,942,000 in base fuel revenues. The Stipulation provides for $375,722,000 of operating revenues, $299,084,000 of operating revenue deductions, and $1,040,035,000 of original cost rate base for use in establishing base rates in this proceeding.

9. The costs of rate base and operating revenue deductions reflected in and underlying the Stipulation, as well as the level of operating revenues under present rates, were prudently and reasonably incurred. These rate base costs and operating expenses are necessary for DNCP to meet its obligation to provide safe, adequate, and reliable electric service.

10. The Stipulation provides for certain accounting adjustments, which are set forth in detail at Settlement Exhibit II. The Stipulating Parties agree that settlement regarding those issues will not be used as a rationale for future arguments on contested issues brought before the Commission. The accounting adjustments outlined in Settlement Exhibit II are just and reasonable to all parties in light of all the evidence presented.

11. For purposes of this proceeding, the Stipulation removes certain site separation costs associated with development of the proposed North Anna Nuclear Station Unit 3 from the stipulated revenue requirement, and additionally provides that consideration of the recovery of such costs is reserved for a future proceeding. The Stipulation’s treatment of the North Anna Unit 3 site separation costs is appropriate, just and reasonable to all parties in this case.

EDIT Refund

12. The Stipulation provides that the appropriate level of excess deferred income taxes (EDIT) to be refunded to customers in this case is $15,708,000 (on a pre-income-tax basis), which includes EDIT associated with the January 1, 2017, reduction in the North Carolina corporate state income tax rate from 4% to 3%.

13. DNCP shall implement a decrement rider, Rider EDIT, to refund EDIT to customers over a two-year period on a levelized basis, with a return. As reflected on Settlement Exhibit IV, the appropriate amount to be credited to customers is a total of $16,816,000, which should be credited to customers via a rate that is calculated using the sales shown in Column 1 of Company Rebuttal Exhibit PBH-1, Schedule 11. The ratemaking treatment of the EDIT regulatory liability set forth in the Stipulation is just and reasonable to all parties in light of all the evidence presented.

Implementation of Session Law 2015-6 (House Bill 41)

14. Pursuant to Section 2.4.(a) of House Bill 41 (HB 41), the Commission must adjust the rate for the sale of electricity, piped natural gas, and water and wastewater service to reflect all tax changes enacted in Session Law 2013-316 (HB 998). Under G.S. 105-130.3C, as enacted in HB 998, an automatic reduction in the State corporate income tax rate from 4% to 3% will become effective for the taxable year beginning on or after January 1, 2017, because certain net General Fund tax collection levels were met for the State's fiscal year 2015-2016. The base non-fuel rate revenue requirement in the Stipulation reflects the 3% North Carolina state income tax (SIT) rate effective for the taxable year beginning on or after January 1, 2017.

Nuclear Refueling and Outage Expense Levelization Accounting

15. Section VII of the Stipulation provides that the Company may use levelization accounting for nuclear refueling costs, as described in the testimony of Public Staff witness Fernald and Fernald Exhibit 3. The levelization accounting treatment of the nuclear refueling costs set forth in the Stipulation is just, reasonable and appropriate.

Coal Combustion Residuals (CCR) Costs

16. DNCP's actions through June 30, 2016, in addressing CCR remediation have been prudent, and its CCR costs incurred through June 30, 2016, are reasonable.

17. Section VIII of the Stipulation provides for the Company's deferral and recovery of CCR expenditures incurred through June 30, 2016, and that such costs be amortized over a five-year period. Section VIII of the Stipulation also provides that by virtue of the Commission's approval in this proceeding of a mechanism to provide for recovery of CCR expenditures incurred through June 30, 2016, DNCP has continuing authority pursuant to the Commission's August 6, 2004 Order in Docket No. E-22, Sub 420, to implement asset retirement obligation (ARO) accounting and to defer additional CCR expenditures for consideration for recovery in a future rate case, without prejudice to the right of any party to take issue with the amount or the treatment of any deferral of ARO costs in a future rate case or other appropriate proceeding.

18. The ratemaking treatment of the CCR costs set forth in the Stipulation, as well as the other provisions of the Stipulation regarding CCR costs, are just and reasonable to all parties in light of all the evidence presented.

Regulatory Assets

19. Section XI of the Stipulation provides for deferral accounting treatment and recovery over a three-year period on a levelized basis of deferred post-in-service costs for the Warren County CC and Brunswick County CC.

20. Section XI of the Stipulation also provides for deferral accounting treatment and recovery of the Chesapeake Energy Center (CEC) impairment and closure cost regulatory assets, as proposed by DNCP witness McLeod and further modified by Public Staff witness Fernald.

21. The Stipulation also provides for deferral accounting treatment and recovery of certain regulatory assets and liabilities expiring in 2017 as proposed by Public Staff witness Fernald, which is set forth in Section XI of the Stipulation.

22. The Stipulating Parties agreed to, and by the Stipulation requested Commission approval of, deferral accounting treatment as proposed by Company witness McLeod of costs associated with the beyond design basis studies mandated by the Nuclear Regulatory Commission (NRC) for North Carolina jurisdictional purposes. Through the Stipulation, the Company committed to comply with Commission Rule R8-27(a)(2) prior to establishing any regulatory assets and liabilities for North Carolina jurisdictional purposes in the future.

23. For the present case, the deferral and recovery of the deferred costs presented in the Stipulation is just and reasonable to all parties in light of all the evidence presented.

Accounting for Deferred Costs

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

Accounting and Reporting Recommendations

25. Section XIII of the Stipulation provides for certain accounting and reporting commitments by the Company, as recommended by the Public Staff and agreed to by the Company. As a result of the Stipulation, the Company will notify the Commission when the Yorktown Power Station closure occurs and provide estimates of its undepreciated value at the time of closure and the level of costs to be incurred for closure. Additionally, the Public Staff's accounting recommendations concerning the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts (USOA) and the service company charges will be addressed by DNCP and the Public Staff in Docket Nos. E-22,

Subs 476 and 477. Further, the Company agreed in the Stipulation to provide the Public Staff, within 90 days of the date of the Stipulation, with a presentation regarding its accounting practices for non-nuclear asset retirement obligation costs.

Base Fuel Factor

26. The Stipulation provides for a total decrease in DNCP's annual base fuel revenues of $8.942 million from its North Carolina retail electric operations, based on a base fuel factor of 2.073 cents per kilowatt-hour (kWh) (including regulatory fee), which is just and reasonable to all parties in light of all the evidence presented.

27. The base fuel factor should be differentiated between customer classes as provided on Company Rebuttal Exhibit PBH-1, Schedule 9, Page 2.

28. The Stipulation also provides for an adjustment to the Company's base fuel and non-fuel expenses to reflect 78% as a proxy for the fuel cost component of energy purchases for which the actual fuel cost is unknown (Marketer Percentage), with the remaining 22% of the cost of energy purchases being recovered by DNCP in base rates. This represents a reduction from the Company's current Marketer Percentage of 85%. The 78% Marketer Percentage agreed to in the Stipulation is reasonable and appropriate for use in this proceeding. The 78% Marketer Percentage shall remain in effect until the Company's next base rate application or the Company's 2018 application to adjust its annual fuel factor, whichever occurs first.

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

29. Based on the expert witness evidence, the public witness evidence, and the Stipulation, the 51.75% common equity and 48.25% long-term debt, as set forth at Section II.B of the Stipulation, is a just, reasonable, and appropriate capital structure for DNCP in this general rate case.

30. DNCP's June 30, 2016, actual long-term debt cost of 4.650% is appropriate for use in this proceeding.

31. Based on the expert witness evidence, the public witness evidence, and the Stipulation, the rate of return on common equity that the Company should be allowed the opportunity to earn is 9.90% as set forth at Section II.B of the Stipulation. This rate of return on common equity is just, reasonable, and appropriate for DNCP in this general rate case.

32. Based on the expert witness evidence, the public witness evidence and the Stipulation, the overall rate of return that the Company should be allowed the opportunity to earn on the Company's invested capital, including its costs of equity and long-term debt, is 7.367%, as set forth at Section II.B of the Stipulation. This overall rate of return is just, reasonable, and appropriate for use in this general rate case.

33. The authorized levels of overall rate of return and rate of return on common equity set forth above are supported by competent, material, and substantial record evidence, are consistent with the requirements of G.S. 62-133, and are fair to DNCP's customers generally and in light of the impact of changing economic conditions.

34. With respect to the foregoing ultimate findings on the appropriate overall rate of return on rate base and allowed rate of return on common equity for use in this proceeding, the Commission relies on the following more specific findings of fact:

a. DNCP's currently authorized overall rate of return on rate base and allowed rate of return on common equity are 7.80% and 10.20% respectively.[3]

b. DNCP's current base rates became effective on November 1, 2012, and have been in effect since that date.

c. In its Application, DNCP sought approval for rates based on an overall rate of return on rate base of 7.88% and an allowed rate of return on common equity of 10.50%.

d. In the Stipulation, the Stipulating Parties seek approval of an overall rate of return on rate base of 7.367% and an allowed rate of return on common equity of 9.90%.

e. From January 2013 through September 2016, the average authorized ROE for vertically integrated electric utilities was 9.87%. Of the 77 cases decided during that period, 35 included authorized returns of 9.90% or higher. The Commission is not specifically relying on past rate of return on equity determinations authorized for other utilities in determining DNCP's cost of equity and ROE in this case; however, it is appropriate to note such past determinations as a check or as corroboration of the Commission's decision regarding the cost of equity demonstrated by the evidence in the present proceeding.

f. The stipulated overall rate of return on rate base of 7.367% and allowed rate of return on common equity of 9.90% are supported by credible, competent, material, and substantial evidence.

g. The 9.90% rate of return on equity falls between the 10.5% ROE initially requested by the Company and the ROEs recommended by ROE witnesses for Nucor and CUCA (9.0% and 8.6%) and the Public Staff (9.3% before supporting the settlement ROE of 9.90%) in this case.

h. It is appropriate to give substantial weight to the high end of the range of results from Public Staff witness Hinton's updated comparable earnings analysis, where the three highest ROE results - 10.0%, 9.9% and 9.7% - average 9.867%.

[3] Virginia Electric & Power Co*.,* Docket No. E-22, Sub 479, Order Granting General Rate Increase, (Dec. 21, 2012) (2012 Rate Order), Order on Remand (July 23, 2015) (2015 Remand Order).

i. It is also appropriate to give substantial weight to an average of a combination of the updated analytical results of DNCP witness Hevert. The average of his high growth rate multi-stage Discounted Cash Flow (DCF) results, his Capital Asset Pricing Model (CAPM) Value Line market risk premium results, and his bond yield plus risk premium results, is 9.86%.

j. It is not appropriate to approve the single number recommendation of any of the ROE witnesses in this case, nor any one analytical method. Rather, a 9.90% ROE represents a reasonable middle ground, avoiding the extremes reflected in the recommendation of the Company witness on the one end and the recommendations of intervenor witnesses on the other end. A 9.90% ROE is supported by witness Hinton's comparable earnings results. It is also supported by the averaging of witness Hevert's high growth rate multi-stage DCF results, CAPM Value Line market risk premium results, and bond yield plus risk premium results.

k. Substantial expert evidence presented in this matter, uncontroverted by other expert testimony on the subject, indicates that the overall economic climate in North Carolina (as well as nationally) continues to improve. This evidence includes data and projections from reliable sources indicating that in the few months before the hearing in this matter: (1) unemployment rates were declining; (2) real gross domestic product growth was continuing; (3) median household income was growing; and (4) residential electricity costs remain well below the national average. In DNCP's service territory specifically, such data show that: (1) economic conditions remain difficult for many people; (2) but recent changes in economic conditions have been positive, as unemployment has fallen considerably in the last several years and per capita income has been growing.

l. During four public hearings held in Halifax, Manteo, Elizabeth City, and Williamston, the Commission heard testimony regarding economic conditions and the potential impact of DNCP's proposed rate increase on the Company's customers. No public witnesses appeared at the hearing held in Raleigh. Of the 120,000 DNCP retail customers in North Carolina, 26 public witnesses testified at the hearings, many of whom testified that the rate increase was not affordable to many customers, including senior citizens, persons on fixed incomes, persons with disabilities, the unemployed and underemployed, and the poor. The Commission has considered this public witness testimony in its deliberations in setting just and reasonable rates for DNCP, including its determination that a 9.90% ROE and a 51.75% equity component of the stipulated capital structure are reasonable.

m. The rate increase approved in this case, which includes the approved ROE and capital structure, will be difficult for some of DNCP's customers to pay, in particular the Company's low-income customers.

n. The 9.90% rate of return on equity takes into account the impact of changing economic conditions on consumers. The authorized revenue amount available to pay a return on equity is lower for DNCP because the Stipulation reduced downward DNCP's requested revenue requirement, and this reduction is intertwined with the decision on rate of return on equity in that it affects the earnings available to investors and the rates customers will pay.

o. No party submitted evidence showing that any regulatory commission applies increments or decrements to the return on equity to account for economic conditions or customer ability to pay.

p. DNCP has made significant capital investments since its last rate case in 2012, much of which relates to its efforts to add new baseload combined cycle generating capacity to its fleet and to expand and strengthen its transmission and distribution infrastructure in northeastern North Carolina and throughout its system. All of these investments further the mission of ensuring reliability, operational excellence, and efficient electric service for DNCP's customers. The Company plans to make additional significant capital investments in the future.

q. Continuous safe, adequate, and reliable electric service by DNCP is essential to the well-being of the people, businesses, institutions, and economy of North Carolina, and access to capital at reasonable rates is critical to DNCP's ability to fund its ongoing capital investment requirements and DNCP's provision of safe, reliable, and cost effective electric service.

r. The 9.90% ROE and the ratemaking capital structure consisting of 51.75% common equity approved by the Commission in this case result in a cost of capital that will enable DNCP by sound management to produce a fair return for its shareholders, and is just, reasonable, and fair to DNCP's customers considering the impact of changing economic conditions on those customers. The resulting cost of capital is as low as reasonably possible and appropriately balances DNCP's need to obtain financing and maintain a strong credit rating with its customers' need to pay the lowest possible rates.

s. The potential difficulties that DNCP's low-income customers will experience in paying DNCP's increased rates will be somewhat mitigated by the $400,000 of shareholder funds that the Company will contribute to assist low-income customers.

<u>Revenue Increase</u>

35. The Stipulation provides for an increase in DNCP's annual electric sales revenues from its North Carolina retail electric operations of $34.732 million. With the stipulated decrease in annual base fuel revenues of $8.942 million, there is a net overall revenue increase of $25.790 million from its North Carolina retail electric operations. The increase in annual non-fuel base rates to be paid by DNCP's North Carolina retail customers is just and reasonable to all parties in light of all the evidence presented.

<u>EnergyShare Contribution</u>

36. Section XV of the Stipulation provides that the Company will make a one-time $400,000 shareholder contribution to the North Carolina EnergyShare program that provides energy assistance to customers in need in the Company's North Carolina

service territory. This $400,000 will be an additional contribution in 2017 on top of the Company's usual annual contribution of about $360,000. This shareholder contribution represents an additional rate mitigation measure that could not have been ordered by the Commission without agreement by the Company. This provision of the Stipulation is just and reasonable to all parties in light of all the evidence presented.

Cost of Service Allocation Methodology

37. The Stipulation provides for the use of the Summer-Winter Peak and Average (SWPA) methodology to allocate the Company's cost of service to the North Carolina jurisdiction and among the customer classes in this case. The Stipulating Parties agreed that use of the SWPA methodology for allocation between jurisdictions and among customer classes shall not be a precedent for, and may be contested in, future general rate case proceedings. The Stipulating Parties further agree that the Company's proposed adjustment to DNCP's recorded summer and winter peaks to recognize the peak demand contributions of non-utility generators (NUGs) interconnected to the Company's distribution system is appropriate and reasonable. The SWPA cost of service methodology, as adjusted by DNCP to account for the peak demand contribution of distribution-connected NUGs, is appropriate for determining the Company's North Carolina jurisdictional and retail customer class cost allocation and responsibility for purposes of this case.

38. DNCP's adjustment to the peak component of SWPA appropriately recognizes the impact non-utility generators have on DNCP's utility system and is appropriate for use in this proceeding.

39. The SWPA cost of service methodology, as adjusted by DNCP, has been used in this Order to determine the appropriate levels of rate base, revenues, and expenses for North Carolina retail service.

40. DNCP's continued use of the SWPA methodology in this proceeding properly assigns production plant costs to all customer classes, including the Schedule NS Class in recognition of its significant use of the Company's generation throughout the year.

41. It is not reasonable nor necessary at this time to require the Company to re-evaluate the issues addressed in the 1994 fuel study filed in Docket No. E-22, Sub 333, as raised by Nucor.

Rate Design

42. For purposes of apportioning and assigning the approved increase in base non-fuel and base fuel revenues between the North Carolina customer classes in this proceeding, the apportionment and rate design principles presented by Company witness Haynes in his direct and rebuttal testimony, as modified in Section V of the Stipulation, are reasonable, appropriate, and nondiscriminatory. The Stipulation further provides that in developing rates based upon the foregoing class apportionment, the Company agrees

to recover 100% of the stipulated revenue increase through the energy and demand components of rates and not to increase the basic customer charge component of rates.

Schedule 6L

43. The new Rate Schedule 6L, as amended in Company Rebuttal Exhibit PBH-1, Schedule 12 to eliminate the NAICS “Manufacturing” classification as part of the qualification for this rate schedule, is reasonable, nondiscriminatory, and should be approved.

Utilities International Model (UI Model)

44. The Stipulation provides that DNCP will work with its cost of service model vendor to determine whether an application can be produced that would enable an intervenor or the Public Staff to perform certain cost of service model functionalities in Excel, generally including manipulating allocation factors to prepare their own cost of service studies in future rate case proceedings. DNCP should work with its vendor, Utilities International, to assess reasonable additional cost of service model functionalities that can be produced in an Excel spreadsheet-based format. DNCP should be prepared prior to filing its next general rate case to release the Excel product to intervenors as requested.

LED Schedule

45. The Stipulation provides that the Company shall develop and file for Commission approval a new LED schedule for North Carolina jurisdictional customers within one year of the Commission’s final order in this proceeding. This provision of the Stipulation is reasonable and appropriate.

Time-Differentiated Rates

46. DNCP currently does not offer a Real Time Pricing (RTP) rate for its service territory in North Carolina. It is reasonable to expect the Company to propose a pilot or experimental RTP rate offering no later than July 1, 2017.

47. The number of DNCP residential customers receiving service on either of the time-of-use rates offered by DNCP in North Carolina is approximately 0.3%. In 2008, the Commission encouraged utilities to increase the utilization of time-differentiated rates. However, the percentage of DNCP’s residential customers participating is smaller now than it was in 2007. Therefore, DNCP should be required to provide a written summary of its time-of-use rates, and its RTP rates, when developed, to each residential customer presently being served and to be served in the future by a smart meter. Further, the Commission approves the terms of the agreement filed herein by DNCP and NCSEA on December 13, 2016.

Terms and Conditions

48. The Stipulation provides that DNCP's Terms and Conditions should be revised as set forth in Item 39 of the Company's Form E-1 filed with its supplemental direct testimony on August 12, 2016. The rate designs, rate schedules, and service regulations proposed by the Company are reasonable, as filed, except as specifically addressed in the Stipulation and this Order.

Quality of Service

49. The overall quality of electric service provided by DNCP is good.

PJM Conditions

50. It is appropriate to relieve the Company from compliance with most, but not all, of the conditions that were imposed by the Commission's April 19, 2005 Order Approving Transfer Subject to Conditions issued in Docket No. E-22, Sub 418. The Company shall continue to file with its annual fuel clause adjustment filing the information required by Paragraph 5 of the November 10, 2004 Joint Offer of Settlement between DNCP and PJM. The Independent Market Monitor (IMM) for PJM shall continue to annually file the information required by Paragraph 6 of that same Joint Offer of Settlement. DNCP committed in the Stipulation to comply with the representations and commitments made in its July 8, 2016 Supplemental Filing with respect to certain obligations, and that provision of the Stipulation is just and reasonable. Further, it is appropriate to require the Company to file as a compliance filing in this case a comprehensive document entitled "Code of Conduct" that shall include all representations and commitments to which the Company will be bound, consistent with this Order.

Acceptance of the Stipulation

51. Based upon all of the evidence in the record, including consideration of the public witness testimony and the record evidence from parties who have not agreed with the Stipulation, the provisions of the Stipulation are just and reasonable to the customers of DNCP and to all parties to this proceeding, and serve the public interest. Therefore, the Stipulation should be approved in its entirety. In addition, the Stipulation is entitled to substantial weight and consideration in the Commission's decision in this docket.

Just and Reasonable Rates

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

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

The evidence supporting these findings of fact and conclusions is contained in the verified Application and Form E-1 of DNCP, the testimony and exhibits of the witnesses, and the entire record in this proceeding. These findings and conclusions are informational, procedural, and jurisdictional in nature, and are not contested by any party. In addition, the Commission finds and concludes that the Company's use of a test period of the 12 months ended December 31, 2015, with appropriate adjustments through June 30, 2016, comports with the requirements of G.S. 62-133 and Commission Rule R1-17, and is appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

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

On March 1, 2016, pursuant to Commission Rule R1-17(a), DNCP filed notice of its intent to file a general rate case application. On the same date, DNCP filed a letter informing the Commission of the Company's intention to propose accounting adjustments to include an appropriate level of amortization of deferred post-in-service costs associated with the Company's Warren County Power Station (Warren County CC) in its rate case revenue requirement.

On March 31, 2016, DNCP filed its Application and initial direct testimony and exhibits, seeking a net increase of approximately $ 51,073,000 in its annual electric sales revenues from its North Carolina retail electric operations. The Application is based on a requested rate of return on common equity (ROE) of 10.50%, an overall rate of return of 7.88%, an embedded long-term debt cost of 4.889%, and DNCP's actual capital structure of 53.36% common equity and 46.64% long-term debt, as of December 31, 2015. Further, the Application states that DNCP's 2015 ROE was 5.06%, and its overall rate of return was 4.98%.

The Company's last general rate case was in 2012 in Docket No. E-22, Sub 479. By Order issued on December 21, 2012, the Commission approved an increase in DNCP's base non-fuel revenues of $36,438,000, and a decrease of $14,484,000 in its base fuel revenues. DNCP's current authorized ROE is 10.2%, its authorized overall rate of return is 7.8%, and its authorized capital structure for ratemaking purposes is 51% common equity, 1.5% preferred stock and 47.5% long-term debt.

In its present Application, the Company proposed to implement the non-fuel base rate increase on a temporary basis subject to refund effective on November 1, 2016, along with an accelerated implementation of its new lower base fuel rate – to be filed in August 2016 – as part of any temporary rates (subject to refund) proposed to become effective November 1, 2016. The Company also proposed a methodology for returning certain excess accumulated deferred income taxes (EDIT) to customers through a decrement rider, Rider EDIT, over a two–year period; sought authority to use certain deferred accounts to implement a levelization methodology on its books for its nuclear unit refueling and maintenance outage expenses; and requested an adjustment of the Marketer Percentage to 100%. Further, DNCP requested the deferral of several costs that it had incurred. Finally, DNCP requested relief from the regulatory conditions imposed in the PJM Order.

In its supplemental testimony filed on August 12, 2016, DNCP updated the increase sought in its non-fuel base rates and charges to its North Carolina retail customers to $47.8 million. Upon making certain adjustments, DNCP updated the increase sought to $46.8 million in rebuttal testimony filed on September 26, 2016.

The Commission finds and concludes that DNCP's Application satisfies the requirements of G.S. 62-133, et seq., and Commission Rule R1-17. Further, DNCP is a public utility within the meaning of G.S. 62-3(23). Therefore, pursuant to G.S. 62-30, et seq., the Commission has jurisdiction to consider and decide DNCP's Application for a rate increase and other relief.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 6-7

The evidence supporting these findings of fact and conclusions is contained in the testimony of DNCP's witnesses Curtis, Haynes, Hevert, McLeod and Stevens, Public Staff witness Hinton, the provisions of the Stipulation, and the entire record in this proceeding.

On October 3, 2016, DNCP, the Public Staff and CIGFUR I (Stipulating Parties) filed a Stipulation resolving all of the issues among the Stipulating Parties. The Stipulation is based on the same test period as the Company's Application. In summary, the Stipulation provides:

- A $34.7 million increase in DNCP's annual non-fuel base revenues;
- A $8.9 million decrease in DNCP's annual fuel base revenues;
- A 2-year Excess Deferred Income Taxes decrement rider (Rider EDIT) returning to ratepayers excess deferred income taxes in the amount of approximately $15.7 million beginning November 1, 2016;
- An overall base rate increase for all customer classes of approximately 7.47%, excluding the effect of any 2017 Fuel Factor Riders and the Rider EDIT decrement;
- An increase to residential customers' bills for 2017 limited to 0.08%, taking into account the effect of the base rate increase, overall fuel decrease, the Company's proposed 2017 Fuel Factor Riders, and the Rider EDIT decrement;
- A rate of return on equity of 9.90% and an overall rate of return on rate base of 7.367%;

- A capital structure for ratemaking purposes consisting of 51.75% equity and 48.25% long-term debt;

- An embedded cost of debt of 4.650%;

- A 5-year amortization of costs associated with coal combustion residual expenditures incurred through June 30, 2016;

- Withdrawal from this case of DNCP's request to recover site separation costs associated with the proposed North Anna 3 nuclear plant. Consideration of the recovery of any such costs would be reserved for a future proceeding;

- Allocation of the Company's cost of service based on the Summer/Winter Peak and Average (SWPA) method;

- A one-time $400,000 shareholder contribution by DNCP to the EnergyShare program that provides energy assistance to customers in need in the Company’s North Carolina service territory;

- Deferral of the post-in-service costs of the Warren County CC and Brunswick County CC generating facilities;

- Deferral of the Chesapeake Energy Center (CEC) impairment and closure costs; and

- Subject to certain clarifications and conditions, release of DNCP from further compliance with the regulatory conditions imposed by the Commission in its Order Approving Transfer Subject to Conditions, Docket No. E-22, Sub 418 (April 19, 2005), approving DNCP's participation in PJM.

In his testimony in support of the Stipulation, filed on October 3, 2016, DNCP witness Curtis stated that the Company was able to reach a settlement with the Public Staff after extensive discovery conducted by the Public Staff and other intervenors. Witness Curtis further testified that the Stipulation is the product of give-and-take negotiations between the Company and the Public Staff. He testified that through extensive discussions and negotiations with the Public Staff, the Company and Public Staff were able to strike the balance between reasonable rates for customers and the Company's need to attract capital in order to continue providing safe and reliable service. In addition, witness Curtis testified that the Company understands that the Commission must set just and reasonable rates, including the authorized ROE, in a way that balances the economic conditions facing DNCP’s customers with the Company’s need to attract capital in order to continue providing safe and reliable service. He testified that the Stipulation mitigates the impact on DNCP’s customers of the rate relief provided to the Company through, for example, the agreed-upon cost of service adjustments, the reduced overall revenue requirement, the decreased base fuel factor, and the refund of excess deferred income taxes through decrement Rider EDIT. Witness Curtis also noted that the Stipulation provides significant benefits that could not otherwise be ordered by the Commission, including the accelerated refund of the current fuel over-recovery through decrement Rider A1, and the Company's agreement to make a $400,000 contribution of shareholder funds to the North Carolina EnergyShare program, to provide energy assistance to customers in need in DNCP's North Carolina service area.

Company witness Hevert filed testimony on October 3, 2016, in support of the Stipulation. He testified that although the ROE agreed upon in the Stipulation is below the lower end of his recommended range (i.e. 10.25%), he recognizes that the Stipulation represents the give-and-take regarding multiple issues that would otherwise be contested.

Company witnesses Stevens and McLeod filed joint testimony on October 3, 2016, in support of the Stipulation. They testified that subsequent to the filing of the Company's Application, DNCP, the Public Staff and other intervenors engaged in substantial discovery, and that the parties filed testimony asserting their positions, with DNCP also filing rebuttal testimony responding to the other parties' positions. Witnesses Stevens and McLeod further testified that after lengthy negotiations the Company and Public Staff arrived at a settlement of all of the issues between them. Witnesses Stevens and McLeod also noted that DNCP negotiated in good faith with other parties, and was able to reach a settlement with CIGFUR I. In addition, witnesses Stevens and McLeod stated that the Stipulation is the result of give-and-take negotiations in which each party made substantial compromises on certain issues in order to gain compromises from the other party on other issues, and that the Stipulating Parties believe the results reached are fair to the Company and its customers. Finally, they noted that the Stipulation resolves all issues among the Stipulating Parties without the necessity of contentious litigation.

DNCP witness Haynes also filed testimony on October 3, 2016, in support of the Stipulation. Witness Haynes testified that he believes the Stipulation constitutes a just and reasonable approach to establishing DNCP's cost of service, apportioning the costs among the customer classes, and designing the Company's rates and charges. Moreover, he testified that the Stipulation represents a compromise between differing interests in a number of respects, including CIGFUR I's support of the Company's proposed SWPA cost allocation methodology, and CIGFUR I's withdrawal of its request that an additional portion of the rate increase be allocated to the NS Class.

Public Staff witness Hinton also filed testimony in support of the Stipulation on October 3, 2016. Witness Hinton testified that the Public Staff and DNCP have fundamentally different views of the current market conditions and cost of capital, and that neither party persuaded the other to change its views. He testified that the Public Staff and DNCP nonetheless found a way to bridge their differences and to reach agreement on a proposed ROE and capital structure. Witness Hinton further stated that the stipulated ROE of 9.90% and equity ratio of 51.75% came about as a result of various compromises on other issues by both DNCP and the Public Staff. In addition, Public Staff witness Fernald testified to her belief that the Stipulation is in the public interest.

The Stipulation has not been adopted by all of the parties to this docket. Therefore, the Commission's determination of whether to accept or reject the Stipulation is governed by the standards set out by the North Carolina Supreme Court in State ex rel. Utilities Commission v. Carolina Utility Customers Association, Inc., 348 N.C. 452, 500 S.E.2d 693 (1998) (CUCA I), and State ex rel. Utilities Commission v. Carolina Utility Customers Association, Inc., 351 N.C. 223, 524 S.E.2d 10 (2000) (CUCA II). In CUCA I, the Supreme Court held that

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

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

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

The Commission gives substantial weight to the testimony of DNCP witnesses Curtis, Haynes, McLeod and Stevens describing the Stipulating Parties' efforts in negotiating the Stipulation. Further, the Commission gives significant weight to the settlement testimony of Public Staff witnesses Fernald and Hinton, which in their discussion of the benefits that the Stipulation will provide to customers and their testimony describing the compromise reflected in the Stipulation's terms indicate the Public Staff's commitment to fully represent the using and consuming public. In addition, the Commission gives some weight to the fact that the settlement was not reached until October 3, 2016, the day before the expert witness hearing began. Prior to that date, DNCP, the Public Staff and CIGFUR I pre-filed the testimony of their experts setting forth their litigation positions on the issues. That indicates to the Commission that the Stipulating Parties were fully prepared to litigate the contested issues in the event that a settlement was not reached.

As a result, the Commission finds and concludes that the Stipulation is the product of the give-and-take among the Stipulating Parties during their settlement negotiations in an effort to appropriately balance DNCP's need for increased revenues and its customers' needs to receive safe, adequate, and reliable electric service at the lowest possible rates. In addition, the Commission finds and concludes that the Stipulation was entered into by the Stipulating Parties after substantial discovery and negotiations, and that it represents a proposed negotiated resolution of the matters in dispute in this docket among the Stipulating Parties. As a result, the Stipulation is material evidence to be given appropriate weight in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 8-11

The evidence supporting these findings of fact and conclusions is contained in DNCP's verified Application, the direct, supplemental and rebuttal testimony and exhibits of the witnesses, the Stipulation, and the entire record in this proceeding.

Rate Base

Per Settlement Exhibit I of the Stipulation, the amount of original cost rate base is $1,040,035,000. A breakdown of the components of the original cost rate base is as follows (000's omitted):

Line No.	Item	After Rate Increase
1	Electric plant in service	$1,947,252
2	Accumulated depreciation and amortization	(716,858)
3	Net electric plant in service (L1 + L2)	1,230,394
4	Materials and supplies	44,916
5	Cash working capital	18,476
6	Other additions	19,607
7	Other deductions	(17,434)
8	Customer deposits	(5,126)
9	Accumulated deferred income taxes	(250,799)
10	Rounding	1
11	Total original cost rate base (Sum of L3 thru L10)	$1,040,035

Discussion of Certain items included in Rate Base

North Anna 3 Site Separation Costs

The Company's Application included certain North Anna Power Station "site separation" plant investments in DNCP's rate base for ratemaking purposes.

Public Staff witness Metz testified that the North Anna Power Station consists of two nuclear reactors, North Anna Units 1 and 2, that are in-service, as well as a potential site for a third nuclear reactor, known as North Anna 3, for which DNCP has not sought a certificate of public convenience and necessity from the Virginia State Corporation Commission (SCC), a determination of need from this Commission pursuant to G.S. 62-110.6, or approval from this Commission of its decision to incur project development costs pursuant to G.S. 62-110.7. In the Company's most recent integrated resource plan (IRP) in Docket No. E-100, Sub 147, DNCP indicates that it is engaged in development efforts in regard to North Anna 3 and is currently pursuing a Combined Operating License from the NRC, which is expected next year.

Witness Metz testified that the Company has included in its cost of service certain capital investment and related expenses associated with site preparation activities for North Anna 3. Site activities for North Anna 3 have involved removing existing structures/buildings that support North Anna Units 1 and 2, and then relocating them outside of the proposed construction zone of North Anna 3.

Witness Metz cited Company witness Mitchell's testimony in SCC Case No. PUE-2015-00027 that stated, "[t]he services supported by each of these assets will be used by the operating Units 1 and 2 as well as Unit 3 if the Company proceeds with construction. However, but for the development of North Anna 3, the development of these assets would not have been needed." Further, in rebuttal in that same case, witness Mitchell stated: "I highlight that but for the development of North Anna 3, these preconstruction site separation activities would not have been needed." Public Staff witness Metz asserted that these costs should be assigned to North Anna 3 and thus removed from DNCP's cost of service in this proceeding.

Similarly, Nucor witness Kollen testified that the site separation costs are solely related to North Anna 3, and not North Anna 1 and 2; therefore, these costs should be removed from rate base and depreciation expense in this proceeding. Witness Kollen additionally testified that in the Company's most recent biennial review, the Virginia SCC removed the North Anna 3 costs from rate base and operating expense that it was not required to include pursuant to Virginia state law (70% of new nuclear construction costs incurred between July 1, 2007, and December 31, 2013).

In rebuttal, Company witness Mitchell provided a brief history of North Anna Units 1 and 2 and explained the decision making process to move forward with North Anna 3 development as part of the Company's resource planning strategy. Witness Mitchell explained that North Anna Units 1 and 2 are benefiting from the new buildings and how these common facilities would eventually support a third nuclear unit at the site. The new facilities, including warehouses, paint shops, welding areas, and vehicle repair shops, are now in service supporting the operating North Anna station, including Units 1 and 2. Witness Mitchell disputed Public Staff witness Metz's characterization of the activities in question as "site preparation activities for North Anna 3" rather than "site separation activities" needed for North Anna, testifying that the new support buildings and infrastructure are needed today in order to continue the safe and reliable operations of North Anna Units 1 and 2. Witness Mitchell testified that this limited universe of costs are site "separation" investments that are now in service and being used to support operations at North Anna Units 1 and 2.

Company witness Stevens disagreed with Public Staff witness Metz's and Nucor witness Kollen's claim that the North Anna site separation costs are solely related to North Anna 3, not to North Anna Units 1 and 2. While the future development of an additional nuclear unit was the driver of the overall project, witness Stevens explained that the site separation assets are common assets that are used and useful assets today at North Anna. Witness Stevens asserted that the Company's accounting for the site separation assets is also consistent with the FERC USOA. As such, he insisted that the site separation assets – which are now in-service and are used and useful today – should not be recorded in construction work in progress (CWIP), but appropriately recorded in plant-in-service.

In his rebuttal testimony, witness Stevens testified that the Virginia SCC did not remove North Anna 3 rate base and operating expenses in the Company's most recent biennial review in Virginia – it included the recovery of 70% of "all costs" related to North Anna 3 as a period expense in the Company's earnings test results for fiscal year 2014. Specifically, he testified that the Virginia legislature has provided explicit direction to the Virginia SCC through Va*.* Code § 56-585.1 regarding the manner in which VEPCO, operating in Virginia as Dominion Virginia Power, shall be authorized to recover the costs of new generating facilities (including recovery of CWIP) and other utility plant. DNCP witness Stevens asserted that the Virginia cost recovery statute should have no bearing on DNCP's recovery of the North Carolina portion of site separation costs under the North Carolina Public Utilities Act. According to witness Stevens, prudently incurred investments in plant-in-service that are used and useful today to serve the Company's North Carolina customers are recoverable under the North Carolina Public Utilities Act.

Witness Stevens asserted in his rebuttal testimony that Nucor witness Kollen's calculation of its adjustment to remove the site separation costs was overstated. According to DNCP witness Stevens, witness Kollen imputed depreciation expense for the assets rather than evaluating the actual depreciation expense reflected in the cost of service. Witness Stevens further testified that Nucor witness Kollen also failed to adjust for accumulated deferred income taxes associated with the site separation assets, thereby incorrectly reducing rate base.

For purposes of this proceeding, the Stipulation provides that certain site separation costs associated with development of the proposed North Anna Nuclear

Station Unit 3 be removed from the stipulated revenue requirement, and that consideration of the recovery of such costs shall be reserved for a future proceeding. Based on this proceeding and the entire record as a whole, the Commission finds and concludes that the Stipulation's treatment of the North Anna Unit 3 site separation costs is appropriate, just and reasonable in this case.

Cash Working Capital (CWC)

In his direct testimony, Company witness McLeod testified that the CWC requirement is based on a lead/lag study prepared based on calendar year 2013 data. According to witness McLeod, the CWC calculation for regulatory purposes is consistent with DNCP's lead/lag study methodology described in the Company's Reply Comments filed in Docket No. M-100, Sub 137, and meets the requirements identified in the Commission's March 21, 2016 Order Clarifying Order on Lead-Lag Study Procedure.

Public Staff witness Fernald identified and proposed a number of adjustments and corrections to the Company's calculation of CWC in her testimony. Additionally, the Public Staff adjusted CWC under present rates to reflect all of the Public Staff's adjustments, in accordance with the Commission's Order in Docket No. M-100, Sub 137.

Nucor witness Kollen testified that the Company's CWC calculation includes the following non-cash expenses: depreciation and amortization expense; deferred federal and state income tax expense, and income available for common. Witness Kollen argued that these non-cash expenses are typically excluded in the lead-lag calculation for that reason, and recommended that the Commission exclude these non-cash expenses from the lead/lag calculation.

As reflected in the rebuttal testimony of Company witness McLeod, DNCP reviewed Public Staff witness Fernald's testimony and exhibits and accepted each of the revisions to the Company's lead-lag study and allowance for CWC, as adjusted by witness Fernald, with the exception of the current state income tax expense lead days. Company witness McLeod testified that the Company disagreed with the Public Staff's correction to the current income tax expense lead days because the Company's expense lead days are based on all current tax payments during the year. Witness McLeod explained that the Company does not necessarily agree with the Public Staff's other revisions to the expense lead and revenue lag days, but has accepted the changes for purposes of this proceeding due to their minor impact on the overall base non-fuel rate revenue requirement.

In his rebuttal testimony, Company witness Stevens disputed Nucor witness Kollen's recommendation to exclude certain non-cash items from the determination of CWC. Witness Stevens explained that the Company's treatment of these items is consistent with the Company's prior practices and this Commission's prior treatment of lead-lag studies and CWC. According to witness Stevens, the Commission had previously addressed the same issue also raised by Nucor in Docket No. M-100, Sub 137, and the Commission overruled Nucor's position. Witness Stevens recommended that the

Commission reject Nucor's adjustment to exclude these expenses from the lead-lag calculation.

The Commission notes that the allowance for CWC in the Stipulation includes an expense lead for current income taxes based on the statutory filing deadlines as proposed by Public Staff witness Fernald. The Commission finds and concludes that for the present case the CWC allowance presented in the Stipulation and agreed to by DNCP and the Public Staff is just and reasonable to all parties in light of all the evidence presented. With respect to Nucor witness Kollen's recommendation regarding certain non-cash items, Nucor has not presented any new evidence to dissuade the Commission from its findings and conclusions addressing inclusion of non-cash items in CWC, as set forth in its May 15, 2015, Order Ruling on Lead-Lag Study Procedure*,* in Docket M-100, Sub 137. Therefore, the Commission rejects Nucor's position regarding the exclusion of certain non-cash items in the calculation of CWC.

Accumulated Deferred Income Taxes Due to Bonus Depreciation on Brunswick County CC

In its supplemental filing, DNCP updated its rate base as of June 30, 2016. DNCP witnesses testified that this calculation also incorporated both the investment and the accumulated deferred income taxes (ADIT) associated with the recently completed Brunswick County CC. Embedded in the ADIT calculation is the impact of bonus depreciation as recorded on the Company's books and records as of June 30, 2016.

Nucor witness Kollen testified that the Company calculated ADIT due to first year bonus depreciation for the Brunswick County CC and included only six months as a subtraction from rate base. According to witness Kollen, bonus depreciation is taken when the asset is placed in service for tax purposes and the entirety of the ADIT is available at June 30, 2016, not just half (or six months) as reflected in the Company's filing. Witness Kollen contended that the Company chose to allocate the bonus depreciation equally over the months in calendar year 2016 in the filing; however, this understates the ADIT available from bonus depreciation at June 30, 2016. Witness Kollen recommended that the Commission reflect the full federal ADIT from bonus depreciation at June 30, 2016.

In response to Nucor witness Kollen, in his rebuttal testimony Company witness Warren discussed the history of bonus depreciation, and explained that bonus depreciation is conceptually no different from other forms of accelerated depreciation; it represents an incentive provided by the government for stimulating capital investment. Witness Warren testified that by allowing businesses to claim accelerated depreciation, Congress essentially causes the government to extend interest-free loans to those enterprises. These loans, according to witness Warren, produce incremental cash (*i.e.,* a reduction in the amount of tax otherwise payable), which are presently available to the utility, but will have to be paid back to the government over time. He further testified that the repayment of such loans is effected by filing future tax returns. Witness Warren explained that the outstanding loan balance is reflected as an ADIT credit, which is properly reflected as a reduction to rate base. In this way, ratepayers receive the entire benefit of the interest-free feature of the loan.

DNCP witness Warren testified that the nature of the disagreement between the Company and witness Kollen is over how much of the ADIT benefit of the Company's 2016 bonus depreciation should be recognized when computing its rate base as of June 30, 2016. The Company contends that it should recognize a half year's worth of the benefit. Witness Kollen contends that it should recognize 100% of the benefit. Witness Warren explained that on DNCP's accounting records, it spreads the benefits of accelerated tax depreciation ratably over the entire year in which the accelerated depreciation is claimed. He stated that this methodology is not one that it applied only to the Brunswick County CC facility or used only for purposes of calculating ADIT in this proceeding. In fact, as of June 30, 2016, the Company's accounting records reflect 50% of the benefit of the bonus depreciation (as well as of the "regular" accelerated tax depreciation on the non-deducted cost) it will claim on its 2016 tax return relating to Brunswick County CC facility. Thus, the ADIT the Company has recognized for purposes of this proceeding conforms to the ADIT it has recognized for all other purposes. Witness Warren further testified that witness Kollen's proposal recognizes an ADIT amount for purposes of the Company's rate base calculation that does not appear on its books and records.

Witness Warren testified that witness Kollen's assertion that the bonus depreciation deduction is taken when the asset is placed in service is both inaccurate and irrelevant. The Brunswick County CC bonus depreciation deduction will not be taken until DNCP files its 2016 federal income tax return in the second half of 2017. According to witness Warren, the critical issue is when the cost-free capital produced by the Company's ability to claim bonus depreciation with respect to the Brunswick County CC facility becomes available to the Company. According to witness Warren, witness Kollen incorrectly presumes that this occurs when the facility is placed in service.

Witness Warren explained that the Company acquires the cost-free capital produced by accelerated depreciation on the facility by reducing its estimated tax payments. As a tax year progresses, corporations are required to make four estimated tax payments so that they pay their tax liability during the year – not when they file their tax return. The amount of the quarterly estimated tax payments, according to Witness Warren, is equal to the lesser of: (1) one-fourth of the tax liability for the year; or (2) an amount calculated by annualizing the taxable income generated during the period. In terms of alternative (1) above, one-fourth of the impact of any bonus depreciation claimed during the year will reduce each of the four estimated tax payments. Thus, the effect of bonus depreciation is spread ratably throughout the year. Therefore, under alternative (1), the ADIT recorded on the Company's books and records as of June 30, 2016, accurately reflects the cost-free capital in its possession. Witness Warren contended that witness Kollen's proposed adjustment imputes a quantity of cost-free capital that, in fact, did not exist as of June 30, 2016.

Witness Warren explained that under alternative (2) above, the applicable tax regulation, Treasury Regulation §1.6655-2(f)(3)(iv), dictates how depreciation must be handled when a taxpayer annualizes its taxable income. It provides that, in determining taxable income for any annualization period, a proportionate amount of the taxpayer's estimated annual depreciation is taken into account. Thus, the benefit of the bonus depreciation actually claimed during the first period is spread over all four periods. Therefore, under alternative (2), the ADIT recorded on the Company's books and records as of June 30, 2016, accurately reflects the cost-free capital in its possession. Witness Warren contended that witness Kollen's proposed adjustment would again impute a quantity of cost-free capital that did not exist as of June 30, 2016.

Further, witness Warren testified that witness Kollen's proposal also creates a conflict with the tax depreciation normalization rules (Normalization Rules). The Normalization Rules are established by §168(i)(9) of the Internal Revenue Code of 1986, as amended, and Treas. Reg. §1.167(l)-1. They are quite complex, but prescribe: (1) how to implement the required tax benefit deferral (*i.e.*, normalization); (2) what can be done with the deferred tax benefit once it is deferred; and (3) under what circumstances the deferred tax benefit can be reversed. Witness Warren explained that accelerated depreciation was enacted by Congress to promote investment by businesses (including utilities) in plant and equipment. However, Congress was concerned that, in the case of a regulated utility whose rates are set by reference to its costs (one of which is tax expense), these incentives could be extracted from the utility and flowed directly to its customers through the rate-setting process, and the benefits would be stripped from the utilities and converted into consumption subsidies for utility customers who did not necessarily use the money to make plant investments. According to witness Warren, this was not Congress' intent, and it included in the tax law a set of rules to prevent this from happening – the Normalization Rules.

Witness Warren further explained that because the Normalization Rules permit rate base to be reduced by the cost-free capital produced by claiming accelerated depreciation, the benefits of accelerated depreciation that those rules intend to preserve can be passed through to ratepayers by ratemaking that presumes the existence of an excessive quantity of cost-free capital. DNCP witness Warren testified that the Normalization Rules therefore impose a limit on the amount of depreciation-related ADIT by which rate base can be reduced. Witness Warren contended that the limitation that is relevant to witness Kollen's proposed adjustment is the one contained in Treasury Regulations §1.167(l)-1(h)(6) entitled "Exclusion of normalization reserve from rate base." Treasury Regulations Section §1.167(l)-1(h)(6)(i) states, in pertinent part:

> [A] taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes under section 167(l) which is excluded from the base to which the taxpayer's rate of return is applied…exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's tax expense in computing cost of service in such ratemaking.

This regulation requires that rate base not be reduced by an ADIT balance unless that balance has been included in the utility's cost of service. Witness Warren testified that the additional six months of ADIT that witness Kollen proposes to factor into the Company's rate base computation has not been included in the Company's cost of service. Witness Warren asserted that only the amount that has been reflected on the Company's accounting records – the amount that it has used in its rate base computation – has been included in cost of service.

Witness Warren testified that as a condition for claiming accelerated tax depreciation (including bonus depreciation) on any of its depreciable assets, a utility must use a normalization method of accounting. Thus, the penalty for a violation in this proceeding would not be confined to the Brunswick County CC facility, but would extend to all of the Company's North Carolina depreciable assets. Witness Warren explained that the penalty for violating the Normalization Rules is draconian. By no longer being able to claim accelerated depreciation, a non-compliant utility would not generate any additional interest-free, governmental loans. Moreover, witness Warren stated that all governmental loans outstanding as of the date of the violation would have to be paid back a good deal more rapidly than would otherwise have been the case. The inability to claim accelerated tax depreciation would result in a significant reduction in the quantity of cost-free loans such depreciation deductions produce. Company witness Warren attested that this would manifest itself in the form of a dramatically reduced ADIT balance. Since the Company's ADIT balance offsets the rate base upon which a return must be allowed, diminished ADIT balances will produce a higher rate base and, consequently, higher rates than had the normalization violation not occurred.

The Stipulation reflects ADIT from bonus depreciation for the Brunswick County CC as of June 30, 2016, as a reduction to rate base as proposed by the Company.

Based upon the evidence presented by Company witness Warren, the Commission concludes that witness Kollen's proposal to reflect the full federal ADIT from bonus depreciation for the Brunswick County CC as a reduction to rate base as of June 30, 2016, is unreasonable and inappropriate. The Commission agrees with Company witness Warren that DNCP acquires the cost-free capital produced by accelerated depreciation on the facility by reducing its estimated tax payments made over the course of the tax year. As of June 30, 2016, the Company had only acquired half of this benefit, which DNCP has appropriately reflected as a reduction to rate base. The Commission, therefore, finds and concludes that the ADIT reflected in the Stipulation associated with the Brunswick County CC bonus depreciation is just and reasonable to all parties in light of all the evidence presented.

Operating Expenses

Operating Expenses per the Stipulation are $299,084,000. A breakdown of the operating expenses allowed in this proceeding is as follows:[4]

Line No.	Item	Amount (000's omitted)
1	Electric operating expenses:	
2	Operations and maintenance:	
3	Fuel clause expenses	$90,686
4	Other operations and maintenance expenses	98,989
5	Depreciation and amortization	60,047
6	Gain / loss on disposition of property	309
7	Taxes other than income taxes	15,233
8	Income taxes	33,820
9	Total electric operating expenses (Sum of L3 thru L8)	$299,084

Discussion of Certain items included in Operating Expenses

Uncollectible Expense

In its Application, DNCP proposed a normalization adjustment to uncollectible expense based on an historical average uncollectible expense rate for the five-year period of 2011-2015. Public Staff witness Fernald presented testimony stating that in 2014, the Company changed its write-off and collection policies for customers with medical certifications. According to witness Fernald, prior to that time, although these customers existed, the Company did not include them in its determination of the reserve for uncollectibles. She further testified that in 2014, DNCP began including customers with medical certifications in its calculation of the reserve, and to implement this policy change the Company recorded a $12.1 million credit accounting adjustment, on a total system level, to its reserve for uncollectibles account, with a charge to uncollectible expense, in order to establish an initial reserve for these customers. Witness Fernald testified that data from 2014 and prior years should not be used to determine an ongoing level of uncollectibles, since data from those years cannot validly be compared with 2015 data. Accordingly, witness Fernald stated that she calculated uncollectibles based on 2015 data, reflecting the Company's current policy of establishing a reserve for customers with

[4] Chart omits 000's.

medical certificates. Witness Fernald noted that the uncollectibles rate utilized by the Public Staff was 0.4814% as compared to the Company's 0.5549% rate.

Company witness McLeod testified that the Company's adjustment based on a five-year historical average expense rate methodology was consistent with the methodology approved by the Commission in the 2012 rate case, Docket No. E-22, Sub 479 (2012 Rate Case), as well as the Company's prior 2010 rate case, Docket No. E-22, Sub 459 (2010 Rate Case). Witness McLeod noted that the methodology approved in the 2012 Rate Case, which the Company followed in its Application, was first proposed by Public Staff witness Fernald in that proceeding. Witness McLeod argued that a change in accounting policy should not negate the use of an historical average since the purpose of using a historic average is to recognize the volatile nature of the expense - capturing both the highs and lows – and include a "normal" level that the Company will incur over a reasonable period of time. He asserted that normalization adjustments are designed to smooth out volatility in interim years including changes in accounting policy.

The Stipulation provides for an adjustment to uncollectible expenses based on 2015 data as proposed by witness Fernald. The Commission finds and concludes that for the present case the accounting adjustment is just and reasonable to all parties in light of the agreement between the Company and the Public Staff in the Stipulation and all the evidence presented.

Major Storm Restoration Expense

The Company proposed a normalization adjustment to non-labor and overtime major storm restoration expenses based on an historical average of costs during the five-year period of 2011-2015. Company witness McLeod testified that this adjustment is appropriate for ratemaking purposes given the unpredictable nature of storm activity, which can cause a material level of expense in a short period of time.

Public Staff witness Fernald proposed to normalize major storm expense based on the average storm costs for the last 10 years, instead of the last five years as proposed by the Company. Witness Fernald testified that the use of a 10-year average is consistent with the normalization of storm costs in the recent rate cases for Duke Energy Carolinas in Docket No. E-7, Subs 909, 989, and 1026, and for Duke Energy Progress in Docket No. E-2, Sub 1023. In addition, due to the unpredictability of both the frequency and cost of major storms, she contended that a 10-year average is more appropriate for use in determining a normalized level. Witness Fernald further recommended that since the Company has a normalized level of storm costs included in rates in this case, costs for future storms should not be deferred nor amortized.

Nucor witness Kollen testified that the data indicates that there is no "normal" storm damage expense and that a "normalized" expense is highly dependent on the number of years used for that purpose, as there are significant differences from year to year. Witness Kollen recommended that the Commission implement storm damage reserve accounting for ratemaking purposes and calculate the storm damage expense using the three most recent years of expense. According to Witness Kollen, this proposal would allow for the tracking of storm damage costs and the recovery of storm damage expenses on a dollar-for-dollar basis with the net over/under recovery position as a component of rate base. Witness Kollen further testified that any storm costs more or less than the expense accrual, under this scenario, would be tracked in the reserve and he suggested that the Commission could periodically adjust the storm damage expense to target a zero reserve balance over time.

In rebuttal testimony, witness McLeod testified that the Public Staff's reliance on a 10-year average understates the normal level of storm expenses that can be expected to occur going-forward. Witness McLeod asserted that the Public Staff's reliance on 10 years of data also fails to take into account operational changes that have occurred over that period of time.

In rebuttal testimony, Company witness Stevens recommended that the Commission reject Nucor witness Kollen's proposal to establish a ratemaking mechanism for tracking DNCP's storm costs. Witness Stevens contended that the methodology presented by Company witness McLeod is reasonable, and that witness Kollen's storm damage tracker goes beyond any known Commission precedent.

The Stipulation provides for an adjustment to major storm restoration expenses based on data during the period January 1, 2010 to June 30, 2016, in effect, including a levelized storm restoration expense level less than the five-year average recommended by the Company and greater than the level proposed by Public Staff. The Commission finds and concludes that for the present case this stipulated level of storm expense is reasonable and appropriate and is just and reasonable to all parties in light of all the evidence presented. The Commission also finds that Nucor witness Kollen's recommendation for the Commission to order a storm cost tracker should not be implemented in light of the Commission's preceding determination to include storm restoration expense in the cost of service.

Annual Incentive Plan Expense

In the Company's Application, Company witness McLeod explained that the annual incentive plan (AIP) represents at-risk compensation paid out to Company employees only upon meeting certain operational and financial goals during the plan year. During 2015, not all of the operational and financial goals of the Company were achieved, and, as a result, less than 100% of at-risk compensation was paid to employees. Witness McLeod proposed in his direct testimony an accounting adjustment that provides for 100% of the plan target based on employees meeting all operational and financial goals during the year.

Public Staff witness Fernald testified that she agreed that incentive pay, such as DNCP's AIP, represents a part of employees' overall compensation. However, witness Fernald explained that the actual amounts paid to employees under the AIP could vary widely. AIP payout percentages in the last five years have ranged from a 20% payout during the test year to 100% payouts in 2013 and 2014. Witness Fernald recommended that the three-year average of the payout percentage, amounting to 73.33%, be used to determine the amount of AIP expense for this proceeding.

Nucor witness Kollen recommended that the ratemaking level of AIP expense should be limited to the lesser of: (a) the expense incurred in the test year, if the Company's actual payout was less than 100% of target; or (b) 100% of target, if its payout exceeded 100% of target. Witness Kollen contended that the concept underlying the AIP is that employees are paid for performance and that a portion of their payroll is at risk and the Commission should not require customers to pay for performance that the Company did not achieve. Witness Kollen proposed to reduce the Company's adjustment from 100%, as proposed, down to 20% to reflect the actual test year payout.

Company witness McLeod testified in rebuttal that the methodology used by the Company in this case is consistent with the methodology approved by the Commission in 2012 Rate Case. Witness McLeod requested that the Commission again allow the Company to incorporate AIP expense at the 100% target payout percentage and to continue to incentivize high employee performance for the benefit of DNCP's customers. Witness McLeod asserted that Nucor witness Kollen's ratemaking adjustment for AIP expense was asymmetric. Witness McLeod testified that the AIP payout percentage during the test year was the single lowest payout in at least the past eight years.

The Stipulation provides for a normalized level of AIP expense based on the three-year average of the payout percentage of 73.33% as proposed by witness Fernald. The record shows that the Company's AIP payout percentage is, on average, well above the 20% payout percentage recommended by witness Kollen. Therefore, the Commission finds and concludes that for the present case the level of AIP expense presented in the Stipulation is just and reasonable to all parties in light of all the evidence presented.

Employee Severance Program Costs

In the Company's supplemental filing, witness McLeod proposed to include a normalized level of employee severance program costs for ratemaking purposes based on the average severance program costs during the years 1994 through 2016. The normalized annual level of severance costs was determined by dividing the average severance program costs by 4.4 years, the average frequency of severance programs as determined by the Company.

Public Staff witness Fernald explained that in the 2012 Rate Case, an ongoing level of severance program costs was included in rates based on the actual costs of the Company's 2010 employee severance program, which at that time was its latest corporate-wide severance program. Witness Fernald discussed DNCP's most recent employee severance program, the Organizational Design Initiative (ODI), which was announced during the first quarter of 2016. Witness Fernald recommended that the level of employee severance program costs for ratemaking purposes in this proceeding be based upon the actual cost of the most recent corporate-wide severance program, amortized over five years. These costs are lower than the employee severance costs allowed in the 2012 rate case, according to witness Fernald, but this reflects the fact that the costs of ODI, and the savings it generated for ratepayers, were lower than those of the Company's previous programs.

Nucor witness Kollen testified that the scope and frequency of prior employee severance has varied considerably, and thus there is no "normal" employee severance program cost. According to witness Kollen, the Company's change in methodology from its initial filing to its update filing demonstrates how the "normalized" expense can be affected by the selection of the programs to be included, the scope and cost of the programs, and the frequency of the programs. It also demonstrates, according to witness Kollen, that one event can significantly affect the average cost, amortization period, and amortization expense.

Witness Kollen recommended that the Commission reject the approach proposed by the Company. Instead, he recommended that the Commission establish a policy that allows the Company to defer the costs of major severance programs, subject to a reasonableness test showing savings in excess of costs, and then amortize and recover those costs over a reasonable period coincident with reflecting the savings in rates, including a return on the unamortized costs. In this case, witness Kollen proposed that the Commission authorize the Company to defer the costs of the ODI, include the costs in rate base, and amortize the costs over a 10-year period, which is equivalent to the longest interval without a severance program in the last 27 years.

In rebuttal testimony, Company witness McLeod explained that in the 2012 Rate Case, the Commission concluded the normalized level of employee severance program costs should reflect "actual historical operating experience" and "should be recovered at a level consistent with DNCP's historical practice…." According to witness McLeod, the Public Staff and Nucor are calculating the going level of severance program costs based solely on ODI, which is by far the least cost program in the past 22 years.

DNCP witness Stevens, in his rebuttal testimony, disputed Nucor witness Kollen's recommendation for the Commission to establish a deferral accounting approach to employee severance program costs. Stevens contended that the deferral mechanism approach suggested by Nucor does not meet the standard or threshold the Commission sets for establishing regulatory assets. According to witness Stevens, the matter is really a debate about the appropriate level of expense to reflect in the cost of service for ratemaking purposes.

The Stipulation provides for a normalized level of employee severance program costs based on the cost of ODI over a five-year period, as recommended by the Public Staff. The Commission finds and concludes that for the present case the accounting adjustment presented in the Stipulation is just and reasonable to all parties in light of all the evidence presented. This approach is consistent with the methodology approved by the Commission in the Company's most recent rate case, which provided for an ongoing level of employee severance program costs and is consistent with DNCP's historical practice of instituting such programs. The Commission in not persuaded by witness Kollen's recommendation to establish a deferral accounting practice for severance costs to be amortized over a protracted period of time. Therefore, the Commission concludes that Nucor witness Kollen's recommendation should be rejected.

Section 199 – Domestic Production Activities Deduction

In supplemental testimony, Company witness McLeod defined the Section 199 – Domestic Production Activities Deduction (Section 199 Deduction or DPAD) as a federal incentive pursuant to Internal Revenue Code §199, which is a permanent benefit available for the generation of electricity – *i.e.,* a federal incentive to manufacture certain goods in the United States. The deduction is equal to 9% of the Company's taxable income attributable to the generation of electricity. Witness McLeod proposed a ratemaking Section 199 Deduction based on a five-year average for the years 2011-2015, on a stand-alone basis for DNCP.

Public Staff witness Fernald explained that the Section 199 Deduction is a tax credit that can be taken by DNCP on the taxable income associated with generation of electricity. A major factor in the computation of taxable income, according to witness Fernald, is the amount of tax depreciation, including bonus depreciation, taken by the Company. Witness Fernald stated that the more bonus depreciation taken, the greater the tax deduction for depreciation expense, and the lower the taxable income. Witness Fernald further explained that the amount of bonus depreciation that could be taken was different in 2011 than what could be taken in 2012 through 2015. In 2011, under the then-current tax laws 100% of the cost of newly acquired property could be deducted as bonus depreciation; however, beginning January 1, 2012, the bonus depreciation deduction decreased to 50% of the cost of the property, where it is set to remain until December 31, 2017. After that it is set to decrease to 40% for 2018, and then to 30% for 2019. Public Staff witness Fernald additionally testified that due to the 100% bonus depreciation deduction in 2011, the Company experienced a net operating loss for that year and was thus unable to utilize the Section 199 Deduction for that tax year. Based on all the above information, witness Fernald concluded that 2011 should not be included in calculating the average Section 199 Deduction, and instead recommended that the Section 199 Deduction be calculated based on the average of the four years from 2012 through 2015, the years for which bonus depreciation was at the current rate of 50%.

Nucor witness Kollen discussed the calculation of the retention factor and claimed the Company failed to include the DPAD in the retention factor (applicable to the increase in taxable income resulting from the rate increase). Witness Kollen testified that the Section 199 Deduction was calculated as 9% of the utility's production taxable income subject to various potential limitations. In the ratemaking process, according to witness Kollen, the test year income tax expense included in the revenue requirement was calculated in two steps. The first step calculates the income tax expense included in operating income and in the operating income deficiency before the rate increase. This calculation includes the Section 199 Deduction on production taxable income, including the effects of any limitations. The second step calculates the income tax expense on the rate increase resulting from the claimed operating income deficiency. The operating income deficiency was grossed up for income taxes and other revenue related expenses through the retention factor to calculate the revenue deficiency or rate increase. Witness Kollen testified that in this second step, the income tax expense on the rate increase was included in the rate increase itself. According to witness Kollen, the calculation assumes that the entirety of the rate increase is subject to income taxes and should reflect all related deductions, including the Section 199 Deduction, and the Section 199 Deduction is fully available without any limitation because the limitations are already embedded into the calculation of the operating income deficiency. Witness Kollen proposed to revise the Section 199 Deduction stating that the federal income tax rate should be reduced by the 9% Section 199 Deduction times the ratio of the production rate base to the sum of the production, transmission, and distribution rate base before it is reflected in the calculation of the retention factor.

In rebuttal testimony, Company witness McLeod explained that Public Staff witness Fernald changed the allocation factor used by the Company for the SIT expense Section 199 Deduction from the Net Book Income factor to the production allocation factor (Factor 1). According to witness McLeod, this is inconsistent with witness Fernald's recommendation to allocate all income tax expense based on the Net Book Income factor.

Witness McLeod concluded that the five-year average Section 199 Deduction produces a reasonable result that should be utilized for ratemaking purposes.

Company witness Warren testified in rebuttal that tax law permits a business to claim a Section 199 Deduction equal to 9% of the lesser of: (1) certain qualified net income (referred to as QPAI); (2) the taxpayer's taxable income; or (3) 50% of the W-2 wages associated with the production of the QPAI. To qualify as QPAI, according to witness Warren, the net income has to be derived from specified activities associated with manufacturing, and the generation of electricity is an eligible activity. Witness Warren asserted that Nucor witness Kollen's proposal was inappropriate because it assumes the DPAD is fully available without any limitation. Witness Warren explained that the DPAD is limited; it is only available for QPAI. Moreover, witness Warren testified that it is limited by taxable income and by 50% of W-2 wages and, therefore, cannot be presumed to be "fully available." Witness Warren contended that witness Kollen's approach implicitly presumes that additional revenue will produce additional QPAI in the same amount and that there will be no taxable income or W-2 wage limitation on the DPAD computation. Unlike other tax deductions, witness Warren explained that the amount of the DPAD is a function of the interaction of a number of variables, and presuming that additional revenues will necessarily produce additional DPAD is overly simplistic.

Witness Warren explained that the Financial Accounting Standards Board (FASB) analyzed and characterized the DPAD in 2004, soon after the enactment of the tax law provision that established the DPAD, and considered how to properly reflect the DPAD for financial reporting purposes. Witness Warren testified that the FASB made a determination that the Section 199 Deduction should not be treated as an adjustment to the income tax rate, but instead, it should be treated as a “special deduction,” which is recognized only in the year in which it is deductible on the tax return. The reason for this conclusion was that the DPAD is contingent upon the future performance of specific activities, including the level of wages. Witness Warren contended that the FASB’s conclusion is consistent with his recommendation to exclude the DPAD from the retention factor.

Company witness Stevens contended that Nucor witness Kollen double counted the Section 199 Deduction by incorporating his own adjustment, while also leaving in the Company’s standalone regulatory accounting adjustment for the Section 199 Deduction in the revenue requirement. According to witness Stevens, witness Kollen also misapplied his own methodology by applying the change in the retention factor to the Company’s entire North Carolina jurisdictional rate base. The proper ratemaking exercise, according to witness Stevens, is to derive a Section 199 Deduction effect only for the additional revenue required to produce the targeted return on equity. Stevens testified that Nucor witness Kollen overstated the impact of the proposed retention factor by $1.5 million. Witness Stevens also testified that other electric utilities under the jurisdiction of the Commission do not utilize a retention factor that is comprised of a Section 199 Deduction, and witness Kollen’s proposal represents a significant deviation from past regulatory practice for electric utilities in North Carolina and would lead to inaccurate results. Witness Stevens recommended that the Commission reject witness Kollen’s proposal.

The Stipulation provides for a normalized level Section 199 Deduction based on an historical average for the four years 2012-2015 as recommended by Public Staff witness Fernald.

Based on the foregoing, the Commission finds and concludes that Nucor witness Kollen’s proposal to include the Section 199 Deduction as a component of the retention factor is inappropriate. The Commission does not find the evidence presented by Nucor witness Kollen convincing, nor does it agree that the incremental revenue increase approved in this case would produce an additional Section 199 Deduction tax benefit. The Commission agrees with the testimony of Company witness Warren that the Section 199 Deduction is more appropriately characterized in the current proceeding as a special deduction, subject to taxable income and wage limitations. Thus, the Commission finds and concludes that it is inappropriate to include the Section 199 Deduction as a component of the retention factor for purposes of determining revenue requirement. Further, the Commission finds and concludes that for the present case the accounting adjustment presented in the Stipulation is just and reasonable to all parties in light of all the evidence presented.

Income Tax Expense Allocation

Public Staff witness Fernald testified that the Company allocated income tax expense as follows:

(1) The Company allocated current and deferred SIT expense to North Carolina retail based on the net book income.

(2) The Company allocated the deferred federal income tax (FIT) expense (i.e., the federal income tax expense associated with revenues and expense items that are recognized in different periods for tax purposes due to timing differences) based on the nature of the timing differences.

(3) The Company allocated the current federal income tax expense based on federal taxable income.

Witness Fernald contended that the income tax expense included in the cost of service for ratemaking should be the amount of income tax expense based on book taxable income, regardless of whether for tax purposes the Company will pay that tax now or later due to timing differences. Therefore, witness Fernald stated, the more appropriate allocation factor for income tax expense is the net book income factor. As such, Public Staff witness Fernald proposed an adjustment to allocate all income tax expense based on net book income.

In rebuttal testimony, Company witness McLeod testified that Schedule 6 (Current Income Tax) and Schedule 7 (Deferred Income Tax) of the Company's cost of service study (COSS) in NCUC Form E-1, Item 45a include detailed calculations of current and deferred FIT expense on both a system level and North Carolina jurisdictional basis. Witness McLeod explained that Schedule 6 contains computations of taxable income for the test period based on the level of operating revenue and expense as determined in the Company's other COSS schedules and an allocation of the various book/tax timing differences, and deferred taxes are allocated among the Company's four jurisdictions in COSS Schedule 7 based on the underlying book/tax timing difference, which corresponds with Schedule 6. Witness McLeod noted that this methodology is consistent with the methodology approved in both of DNCP's most recent rate cases - the 2010 Rate Case and the 2012 Rate Case. Witness McLeod noted that although the Public Staff's audit did not reveal any inherent flaws in the Company's methodology, the Public Staff recommended a complete departure from the methodology proposed by the Company.

Witness McLeod explained that the Company allocates SIT expense to the North Carolina jurisdiction based on the Net Book Income factor because the Company does not have the same level of detail for SIT expense during the test year as it did for FIT expense. Witness McLeod asserted that under these circumstances, it is appropriate to make simplifying assumptions in order to produce a reasonable result for ratemaking purposes. Witness McLeod explained that the Company does, however, have detailed information regarding the book/tax timing differences for FIT expense, and as a result, the methodology in the COSS produces a more accurate and precise allocation of FIT expense than the Public Staff's approach.

According to Company witness McLeod, there are two primary reasons why the methodology in COSS produces a more precise allocation of FIT expense than the Net Book Income factor. First, witness McLeod testified that the Net Book Income factor does not account for all of the permanent differences between book income and taxable income, which causes the Company's effective tax rate to deviate from the statutory rate and will cause the effective tax rate to be different between the Company's jurisdictions. The second item that will cause the Net Book Income factor to not properly reflect North Carolina's appropriate allocable portion of FIT expense, according to witness McLeod, is income tax credits. Witness McLeod argued that since income tax credits are not included in the calculation of the Net Book Income factor, the Public Staff's proposed methodology overrides the allocator designated in the COSS and replaces it with the Net Book Income factor resulting in an inappropriate shift of tax benefits between the jurisdictions. In concluding his testimony, witness McLeod recommended that the Commission allocate FIT expense based on the methodology in the Company's cost of service study since this provides a more precise determination of North Carolina jurisdictional FIT expense.

The Stipulation allocates FIT expense based on the methodology in the Company's cost of service study, as recommended by Company witness McLeod. The Commission finds and concludes that for the present case, the accounting adjustment is just and reasonable to all parties in light of all the evidence presented.

Non-Fuel Variable O&M Expense Displacement

Public Staff witness Maness testified that DNCP made pro forma adjustments to include in the cost of service the full costs of the Brunswick County CC, which began commercial operation on April 25, 2016, including adding incremental non-fuel variable operating and maintenance (O&M) expenses to reflect a full year of operation. With the addition of the Brunswick County CC, witness Maness testified that other plants in DNCP's fleet will operate less frequently, and thus incur fewer non-fuel variable O&M expenses. Therefore, witness Maness asserted, the Public Staff proposed to adjust non-fuel variable O&M expenses to prevent the inclusion in cost of service of more than an annual level of these types of expenses. Otherwise, operating revenue deductions would include both (1) a general annualized and normalized level of variable expenses and (2) the incremental variable expenses related to specific new generation facilities.

In his rebuttal testimony, Company witness McLeod testified that the Company agrees with certain aspects of witness Maness' adjustment for purposes of this case. Specifically, the Company agrees that the addition of the Brunswick County CC will result in some level of purchased power energy savings recovered through base non-fuel rates, and thus proposed in its rebuttal testimony a purchased energy savings adjustment to reduce purchased energy costs proportionate to a pro forma level of the Brunswick County CC generation. However, witness McLeod testified that the Company disagrees with the portion of the adjustment pertaining to energy-related expenses not adjusted elsewhere for growth. Witness McLeod explained that the adjustment is premised on the fact that the Company has included a fully annualized level of Brunswick County CC operating expenses, which was the Company's intent. However, upon further evaluation, the Company determined that its initial adjustment to annualize the Brunswick County CC O&M expense did not include a provision for maintenance outage expenses, which will result in a significant level of cost when incurred. Furthermore, witness McLeod testified that witness Maness' displacement adjustment also does not account for these maintenance outages as the adjustment assumes that the Brunswick County CC will operate for 12 full months. According to witness McLeod, the Public Staff's displacement adjustment, if accepted in full, would understate the level of energy-related expenses necessary to serve the end-of-period customers at the normalized level of generation.

In rebuttal testimony, witness McLeod proposed a new accounting adjustment that reflects an annualized level of purchased energy savings in base non-fuel rates as a result of the Brunswick County CC commencing commercial operation. Witness McLeod recommended that the Commission reject Public Staff witness Maness' displacement adjustment, and incorporate witness McLeod's adjustment that reflects an annualized level of purchased power energy savings for the Brunswick County CC.

The Stipulation reflects an annualized level of purchased power energy savings for the Brunswick County CC as proposed by Company witness McLeod. At the hearing, Public Staff witness Maness testified that while not necessarily agreeing with all aspects of the calculation of this adjustment, the Public Staff accepted it in the Stipulation for purposes of this proceeding only.

Based on the testimony of Public Staff witness Maness and DNCP witness McLeod, and the Stipulation, the Commission finds and concludes that the O&M displacement adjustment, as agreed to in the Stipulation, is just and reasonable to all parties in light of all the evidence presented and should be accepted for purposes of this proceeding.

<u>Depreciation Rates for Warren County CC and Brunswick County CC</u>

Nucor witness Kollen testified that for depreciation expense and rates reflected in the revenue requirement for Warren County CC and Brunswick County CC, the Company used the per books depreciation expense for June 2016, after several adjustments detailed in its workpapers, and annualized the adjusted depreciation expense. According to witness Kollen, the depreciation rates for the per books depreciation expense were provided to the Company by witness John Spanos, a consultant with Gannett Fleming, in a single page letter. The letter included no additional support, analyses, or workpapers, all of which typically are provided in conjunction with an actual depreciation study performed by an expert. The letter states that the depreciation rates "are based on a 36-year life span, interim survivor curves and future interim net salvage percents where applicable. Each of these parameters is established with the general understanding of the new facility and the estimates of comparable Dominion facilities." Witness Kollen stated that the letter provides the proposed interim survivor curve, net salvage rates, and annual depreciation accrual rates for each plant account.

Witness Kollen testified that the Commission should not simply accept the Company's proposed depreciation expense and rates for these units. Witness Kollen contended that there is no support for the parameters used by witness Spanos other than general references to other units owned and operated by the Company. Witness Kollen asserted that he had reviewed the relevant pages from the Company's most recent depreciation studies, and found that the survivor curves and net salvage parameters proposed by witness Spanos did not match any of the Company's other units. He also found that there was a range of life spans for the Company's other CC units from 34 years to 45 years.

In support of his position, witness Kollen testified that one of witness Spanos' colleagues, Ned W. Allis, recommended a 40-year life span for new combined cycle units in a pending Florida Power & Light Company (FPL) proceeding, a change from the 35-year life span that witness Allis recommended in the prior FPL proceeding for new combined cycle units. With that evidence, witness Kollen recommended a 40-year life span for the Warren County CC and Brunswick County CC. Nucor witness Kollen testified that this is the midpoint of the range for the Company's other combined cycle units and is the same life span recommended by witness Allis. Witness Kollen further recommended that the Commission ignore projected interim retirements and net salvage in this proceeding since these units are new and have almost no history of interim retirements or net salvage. Witness Kollen argued that these parameters should be introduced and supported by competent evidence in the Company's next depreciation study.

In response to Nucor witness Kollen's proposal, Company witness Stevens explained in rebuttal that the Company's depreciation consultant provided specific guidance on appropriate depreciation accruals based on informed judgment for Warren County CC and Brunswick County CC. Witness Stevens stated that expert opinion directs that a 36-year useful life for Warren County CC and Brunswick County CC is appropriate given the operating characteristics of these combined cycle units, reviews of Company practice and outlook as they relate to Company operation and retirement, experience of similar existing units within DNCP's generation fleet, and current practice in the electric industry.

DNCP witness Stevens further testified that electric utilities do not experience the exact same performance of a generation facility across the U.S. The expected useful life of a given unit is specific to each utility based on the operating performance of similar units within its owned fleet, the maintenance performance of those units, as well as the expected dispatch characteristics of those units. Witness Stevens contended that a Florida utility's natural gas combined-cycle facility would likely have a different set of operating parameters and conditions and impact on equipment than a natural gas combined-cycle facility constructed by the Company in Virginia.

Witness Stevens also explained that DNCP owns no other combined cycle units with a useful life greater than 36 years. The natural gas combined cycle facilities at Bellemeade, Rosemary, Gordonsville, Chesterfield Unit 7, Chesterfield Unit 8, Possum Point Unit 6, and Bear Garden all have a useful life of 36 years as determined by the Company's depreciation consultant. Witness Stevens noted that this depreciation study was filed with the Commission on April 1, 2013, in Docket No. E-22, Sub 493. Therefore, based on the facts presented, he rejected witness Kollen's testimony that a 40-year life span is the midpoint of the range for the Company's other combined cycle units as inaccurate.

With respect to Nucor witness Kollen's recommendation that the Commission ignore interim cost of removal and net salvage into its depreciation accrual rates for Warren County CC and Brunswick County CC in this proceeding, witness Stevens testified that this practice would be contrary to Generally Accepted Accounting Principles and the FERC USOA.

Witness Stevens further recommended that the Commission reject Nucor's proposed adjustment to the depreciation accruals for Warren County CC and Brunswick County CC.

The Stipulation reflects depreciation expense for the Warren County CC and Brunswick County CC based on the depreciation accrual rates proposed by DNCP.

Based upon the evidence presented in this proceeding, the Commission finds and concludes that the depreciation accrual rates proposed by DNCP for the Warren County CC and Brunswick County CC are appropriate and should be utilized for ratemaking purposes in this case. The Commission concludes that the evidence presented by DNCP supports a useful life of 36 years for these facilities as reasonable for ratemaking purposes until the Company performs another depreciation study. The Commission concludes that Nucor witness Kollen's recommendation to ignore interim cost of removal and net salvage is unsubstantiated and witness Stevens' testimony that witness Kollen's proposal would be contrary to Generally Accepted Accounting Principles and the FERC USOA has not been challenged. Accordingly, the Commission finds and concludes that this recommendation should not be adopted.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12-14

The evidence supporting these findings of fact and conclusions is contained in the verified Application, the testimony and exhibits of Company witnesses McLeod, Haynes, and Stevens and Public Staff witnesses Fernald and Floyd, and the Stipulation.

In the Company's Application, Company witness McLeod testified that HB 998 was signed into law on July 23, 2013. According to witness McLeod, prior to the passage of HB 998, the North Carolina SIT rate was 6.9%, and HB 998 made the following changes to the NC SIT Rate:

- Reduced to 6% effective January 1, 2014;
- Reduced to 5% effective January 1, 2015; and
- Reduced to 4% effective January 1, 2016, assuming certain triggering events occurred, as set forth in the legislation.

Witness McLeod explained that after the passage of HB 998, the accumulated deferred North Carolina SIT balance was overstated based on the legislative changes to the statutory corporate tax rate, or in other words, contained "excess" deferred income taxes (EDIT). In its Order Establishing Procedure for Implementation of Session Law 2015-6 in Docket No. M-100, Sub 138 issued on September 11, 2015, the Commission ordered DNCP to hold the EDIT in a regulatory liability account to be refunded to ratepayers in the context of DNCP's next general rate case proceeding. Witness McLeod testified that the Company is proposing a methodology in this case for crediting the North Carolina jurisdictional portion of the EDIT to customers as this is the first general rate case since the Company established the EDIT regulatory liability.

Company witness McLeod proposed to refund the EDIT to customers through a decrement rider over a two-year period (Rider EDIT). This mechanism, according to witness McLeod, provides transparency as the credit is differentiated from the base rate cost of service. Additionally, excluding the credit from the base rate cost of service will defer the need for a subsequent base rate case after the credit is fully amortized. Witness McLeod testified that this approach returns the credit to customers in an efficient and timely manner, and is equitable to both the Company and customers.

Witness McLeod proposed to include capital savings associated with the regulatory liability until the liability is fully returned to customers. According to witness McLeod, the capital savings decline as the regulatory liability is credited to customers over the two-year period; therefore, the revenue requirement during the first year is greater than the revenue requirement in the second year. Witness McLeod discussed the Company's methodology for determining the North Carolina jurisdictional EDIT to be refunded to customers based on a retrospective analysis of the methodologies approved by the Commission for allocating deferred North Carolina SIT expense in DNCP's previous base rate cases.

With respect to the level of SIT expense included the base non-fuel revenue requirement, witness McLeod proposed an accounting adjustment to reduce NC SIT expense for ratemaking purposes based on an apportioned NC SIT rate that includes a 4% statutory rate.

In direct testimony, Company witness Haynes proposed to allocate the Rider EDIT credits to customer classes based upon North Carolina rate revenue for 2015. Witness Haynes developed a decrement rate based upon actual 2015 kWh sales to be applied to each customer's 2015 sales. The total credit amount for each customer will be amortized over 12 months and provided through a monthly bill credit.

Public Staff witness Fernald testified regarding the history of HB 998, noting that it also added a new section, G.S. 105-130.3C, to the General Statutes concerning possible future rate reduction triggers. On August 4, 2016, the North Carolina Department of Revenue announced that pursuant to G.S. 105-130.3C, the corporate tax rate for tax years beginning on or after January 1, 2017, will be reduced from 4% to 3%. Witness Fernald testified that there are no restrictions on how EDIT should be refunded to ratepayers, and explained that the Public Staff believes that the manner in which EDIT should be refunded to ratepayers, including the period over which the EDIT is amortized, should be determined on a case-by-case basis in each utility's next general rate case. In this particular case, witness Fernald explained, in addition to the need for EDIT collected from past ratepayers to be returned to future ratepayers, there are several deferrals, which represent costs incurred to provide service to past ratepayers that will now be recovered from future ratepayers.

In this case, Public Staff witness Fernald proposed an EDIT regulatory liability of $15,708,000, which included the additional EDIT related to the decrease in the tax rate from 4% to 3% that was announced on August 4, 2016. She identified several regulatory assets and liabilities whose amortizations end in 2017, and proposed re-amortizing the unamortized balances for these assets and liabilities, since these amortizations will end in 2017 and will not continue on an ongoing basis. The total deferred costs and unamortized balances for regulatory assets and liabilities with amortizations ending in 2017 to be recovered from North Carolina ratepayers in this proceeding, as recommended by Public Staff witness Fernald in her testimony, are as follows:

Deferred Costs	Total Cost to be Recovered from NC Ratepayers
Warren County CC Deferral	$10,204,000
Brunswick County CC Deferral	2,957,000
Chesapeak Closure Costs	1,504,000
North Branch Net Proceeds/Costs	175,000
Unamortized Balances	
Unamortized Desighn Basic Costs - Surry	39,000
NUG Buyout Costs - Atlantic	104,000
NUG Buyout Costs - Mecklenburg	481,000
Bear Garden Deferral	593,000
DOE Settlement	(565,000)
Total per Public Staff	$15,492,000

Public Staff witness Fernald testified that both the EDIT liability and the deferred costs and unamortized balances listed above represent revenues collected or costs incurred in providing service to past ratepayers that will now be returned to or recovered from future ratepayers. Consequently, witness Fernald recommended that, instead of a decrement rider as proposed by the Company, the refund of the EDIT liability should be treated in the same manner as the recovery of these deferred costs and unamortized balances based on the circumstances in this proceeding. Therefore, witness Fernald recommended that both the EDIT liability and the deferred costs and unamortized balances listed above be included in the cost of service through a levelized amortization. Since the difference between the impact on rates of amortizing the EDIT liability and the deferrals and unamortized balances over three years and the impact of amortizing them over five years is not substantial, witness Fernald recommended that the levelized amortization of the EDIT liability and deferred costs and unamortized balances listed above be amortized over a three-year period using the after-tax rate of return recommended by the Public Staff in this proceeding.

With respect to the level of SIT expense included the base non-fuel revenue requirement, Public Staff witness Fernald proposed accounting adjustments to reflect the reduction in the North Carolina corporate tax rate from 4% to 3% effective for taxable income on or after January 1, 2017.

Public Staff witness Floyd testified that he recommended the Commission reject DNCP's proposed Rider EDIT. Witness Floyd stated that the Public Staff is concerned that although the EDIT was collected from customers over many years, that it will only be repaid to those who were customers during 2015. Witness Floyd testified that he believed witness Fernald's approach to the EDIT credit to be best as it returns the EDIT to all customers and removes the need for a Rider.

In rebuttal testimony, Company witness Stevens testified that a decrement rider provides greater precision in order to demonstrate to multiple constituents – the Commission, North Carolina customers, and the North Carolina General Assembly – that the amount to be refunded did in fact get refunded. Witness Stevens testified that a decrement rider provides greater transparency on the EDIT refund to North Carolina customers. DNCP's decrement rider approach, according to witness Stevens, is preferable because it credits the EDIT back to North Carolina customers more quickly in two years compared to the Public Staff's recommended three years.

Company witness McLeod accepted the total EDIT regulatory liability of $15,708,000 presented by Public Staff witness Fernald. Witness McLeod also accepted the Public Staff's recommendation to calculate the EDIT regulatory liability amortization on a levelized basis using an annuity factor. These changes were reflected in the Rider EDIT credit amounts presented in witness McLeod's rebuttal schedules and exhibits. Witness McLeod also accepted witness Fernald's accounting adjustments to reduce the level of NC SIT expense in the base non-fuel revenue requirement to reflect the reduction in the NC corporate tax rate from 4% to 3% effective for taxable income on or after January 1, 2017.

With respect to Rider EDIT, Company witness Haynes proposed that after Year 1, any over or under-recovery of the credit amount should be deferred and added (or subtracted) as appropriate from the Year 2 credit amount. Such amount should be allocated based upon the annualized revenue in witness Haynes' rebuttal exhibits. Witness Haynes proposed that prior to the tenth month from the effective date of the Year 2 rider, DNCP will provide an analysis to the Public Staff to evaluate if the total rider credit will be provided at the end of Year 2. For any deviation between the total rider credit and the projected credit provided to customers, the Company and the Public Staff will work together to develop an adjustment to the Rider EDIT to minimize the deviation over the remaining months of Rider EDIT being in effect.

The Stipulation provides that the appropriate level of EDIT to be refunded to customers in this case is $15,708,000 (on a pre-tax basis), which includes EDIT associated with the January 1, 2017, reduction in the North Carolina corporate state income tax rate from 4% to 3%. DNCP shall implement a decrement rider, Rider EDIT, as described in the rebuttal testimony of Company witnesses McLeod and Haynes, to refund EDIT to customers over a two-year period on a levelized basis, with a return. As shown on Settlement Exhibit IV, the appropriate amount to be credited to customers is

$16,816,000, which should be credited to customers via a rate that is calculated using the sales shown in Column 1 of Company Rebuttal Exhibit PBH-1, Schedule 11.[5]

Further, pursuant to Section 2.4.(a) of Session Law 2015-6, the Commission must adjust the rate for the sale of electricity, piped natural gas, and water and wastewater service to reflect all of the tax changes as enacted in HB 998. Under G.S. 105-130.3C, as enacted in HB 998, an automatic reduction in the State corporate income tax rate from 4% to 3% will become effective for the taxable year beginning on or after January 1, 2017, because certain net General Fund tax collection levels were met for the State's fiscal year 2015-2016. The base non-fuel rate revenue requirement in the Stipulation appropriately reflects the 3% NC SIT rate effective for the taxable year beginning on or after January 1, 2017.

The Commission finds and concludes that for the present case the ratemaking treatment of the EDIT regulatory liability presented in the Stipulation is just and reasonable to all parties in light of all the evidence presented. The Commission also finds and concludes that the base non-fuel rate revenue requirement in the Stipulation reflects the 3% NC SIT rate effective for the taxable year beginning on or after January 1, 2017.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The evidence supporting this finding of fact and these conclusions is contained in the verified Application, the Stipulation, the testimony and exhibits of the DNCP and Public Staff witnesses, and the entire record in this proceeding.

In the Company's Application, Company witness McLeod requested Commission approval of a levelization methodology on its books and records for its nuclear refueling and maintenance outage expenses. Witness McLeod testified that DNCP operates four nuclear units: two units at Surry and two units at North Anna. The Company utilizes a "3/3/2" planning practice for scheduling nuclear outages, meaning the Company performs three outages in two successive years, then two outages every third year.

According to witness McLeod, the Company incurs substantial outage costs during the refueling outages, and absent the levelization accounting treatment on its books and records, DNCP experiences and will continue to experience significant variability in its annual operating costs which causes the cost of service for one year to appear inconsistent with a previous year. DNCP requested approval of a levelization methodology in order to minimize this variability and to better match the refueling outage expenses with the period over which the benefit is realized. Witness McLeod stated that this request for accounting authority is not intended to modify the Company's existing approach to levelizing nuclear outage expenses for ratemaking purposes. Witness McLeod noted that the Commission approved similar accounting treatment in the most

[5] On October 19, 2016, the Company filed proposed Rider EDIT to be implemented on November 1, 2016. The Rider EDIT rates for each customer class are identified on pages 129 and 260 of the Company's October 19 filing, and the supporting workpapers are included on page 291.

recent general rate case proceedings for Progress Energy Carolinas, now Duke Energy Progress (DEP) and Duke Energy Carolinas (DEC).[6]

Witness McLeod testified that under this accounting methodology, costs incurred during the three months leading up to an outage, costs incurred during the typical two-month outage period, and trailing costs incurred during the three months after an outage are deferred to a regulatory asset account. The deferrals are amortized over the period of the operating cycle between scheduled refueling for the unit, not to exceed 18 months. Amortization begins the month following completion of the outage and adjustments are made for trailing costs.

Public Staff witness Fernald testified that the Company implemented deferral and amortization of nuclear refueling outage costs on its books in April 2014 pursuant to Virginia legislation. Prior to this change, the Company expensed nuclear refueling outage costs in the month that the costs were incurred. According to witness Fernald, the Company has accounted for nuclear refueling outage costs since April 2014 as follows:

(1) The costs related to nuclear refueling outages are recorded to the appropriate O&M expense account as incurred, as was done in the past.

(2) A credit is recorded to FERC Account 407.4 – Regulatory Asset Deferral O&M for the costs being deferred. When this credit is netted against the amount charged to O&M expense, the costs being deferred are in effect removed from the cost of service. The Company decided that costs eligible for deferral include incremental costs incurred three months prior to the outage, during the outage, and three months after the outage. Specific details regarding the types of incremental costs eligible for deferral are provided in Fernald Exhibit 3.

(3) The deferred costs are then amortized over the refueling cycle, not to exceed 18 months, and the amortization expense for the costs is recorded to FERC Account 407.3.

Witness Fernald explained that in prior rate cases, pro forma adjustments have been made to normalize nuclear refueling outage costs for DNCP. With levelized accounting, the costs reflected in the Company's financial statements will be consistent with the ratemaking treatment of the costs, according to witness Fernald. In future rate proceedings, the test period amounts produced by this levelized accounting method will be the starting point in determining normal nuclear refueling outage expenses, subject to appropriate ratemaking adjustments.

Witness Fernald testified that DNCP's nuclear refueling outage deferral window for nuclear refueling outage costs is a longer period of time than that used by DEC and DEP.

[6] Order Granting General Rate Increase, Docket No. E-2, Sub 1023 (May 30, 2013), Finding of Fact No. 31, and Order Granting General Rate Increase, Docket No. E-7, Sub 1026 (Sept. 24, 2013), Finding of Fact No. 36.

Witness Fernald testified that the accounting procedures established by DNCP are used for regulatory purposes in Virginia, and the Public Staff does not believe that the difference in the nuclear refueling outage deferral window necessitates the time and effort required to maintain a different accounting treatment for North Carolina. Public Staff witness Fernald emphasized that the amounts to be recovered for nuclear refueling outage costs are always subject to review in North Carolina rate cases.

Witness Fernald recommended approval of the Company's levelized accounting treatment with the following conditions:

> (1) The regulatory asset associated with the nuclear refueling outage deferral accounting will not be included in rate base in rate cases. The Company has made an adjustment in this proceeding to remove the nuclear refueling outage deferral balance in regulatory assets from rate base.
>
> (2) Under the Virginia legislation, the amortization period is to be no more than 18 months. The amortization period should be consistent with the refueling cycle of the nuclear units, which currently is 18 months. If DNCP changes the frequency of the refueling cycle for any of its nuclear units in the future, the amortization period for the deferral accounting should be changed to reflect the change in the refueling cycle.

Nucor witness Kollen testified that the change in accounting would result in a one-time reduction in maintenance expense. The Company's proposal will delay the nuclear outage expense for accounting purposes by approximately 18 months to reflect the fact that the costs will be deferred when incurred and then amortized to expense over the period between outages instead of being expensed when incurred. According to witness Kollen, if this accounting is authorized by the Commission, the Company's nuclear outage expense will be reduced when each of the next four outages occur, in other words, there will be a one-time savings in O&M expense. Witness Kollen contended that the Company would retain the one-time savings if the Commission does not direct the Company to defer and amortize the savings as a reduction to expense for ratemaking purposes.

Witness Kollen proposed that the Commission adopt the change in accounting for ratemaking purposes, subject to a deferral and amortization of the one-time savings in expense.

In rebuttal testimony, Company witness Stevens testified that Nucor witness Kollen mischaracterized the financial impacts of implementing the nuclear outage levelization accounting methodology on DNCP's books and records. Witness Stevens argued that the new accounting methodology did not change the cost of nuclear outages. Operating expense in the period was reduced when this accounting methodology was first implemented. However, this was not a "one-time savings," but instead a timing difference resulting from implementation of a new accounting methodology.

Witness Stevens argued that witness Kollen's proposal to establish a regulatory liability for nuclear outage expenses is inappropriate as nuclear outage costs are a component of the base non-fuel rate cost of service, and the Company is not recovering these costs dollar for dollar. According to witness Stevens, an analysis demonstrates that the incurred costs in the past few years are greater than the normalized level of nuclear outage costs approved by the Commission in its 2012 Rate Case. The Company incurred system level average costs for this period of $83.680 million compared to the system level costs included in base rates of $78.163 million. Therefore, witness Stevens concluded that there are no one-time savings or windfalls as suggested by witness Kollen.

The Stipulation provides that the Company may use levelized accounting for nuclear refueling costs, as described in the testimony of Public Staff witness Fernald.

The Commission concurs with DNCP and the Public Staff that implementing this nuclear levelization accounting methodology should have no ratemaking implications, contrary to the proposal set forth by witness Kollen. Accordingly, the Commission finds and concludes that Nucor witness Kollen's proposal to establish a regulatory liability for purported one-time savings associated with establishment of the nuclear outage levelization accounting methodology is inappropriate. The implementation of a new accounting methodology for nuclear outage costs does not change the underlying nature and amount of nuclear outage costs incurred by the Company. The Commission further finds and concludes that DNCP's request to implement levelization accounting for nuclear outage and refueling expenses, as set forth in the Stipulation, is hereby granted.

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

The evidence supporting these findings of fact and conclusions is contained in the verified Application, the testimony and exhibits of Company witnesses Curtis, Hevert, Mitchell and McLeod, Nucor witness Kollen, and Public Staff witness Maness, the Stipulation, and the entire record in this proceeding.

DNCP witness Curtis testified that DNCP's coal combustion residual (CCR) expenditures are the result of efforts by DNCP to comply with the United States Environmental Protection Agency's (EPA's) Standards for Disposal of Coal Combustion Residuals in Landfills and Surface Impoundments (CCR Final Rule), which became effective for DNCP on April 7, 2015.

DNCP witness Mitchell testified that the Virginia Department of Environmental Quality incorporated the CCR Final Rule into its solid waste management regulations in December 2015. He stated that DNCP is developing comprehensive closure and storage plans for the CCR impoundments located at DNCP's operating and non-operating coal plants. Witness Mitchell discussed the Company's plans to close or retrofit the ash ponds and landfills at Chesapeake, Yorktown, Chesterfield, Clover, Mt. Storm, Bremo, and Possum Point Power coal-fired generating stations. He testified that the pond and landfill closures or retrofits are in response to the CCR Final Rule regulating the management of CCR stored in ash ponds and landfills. Witness Mitchell explained that the CCR Final

Rule establishes environmental compliance requirements for the disposal of CCR, and provides specifications for construction and closure of CCR ponds and landfills. In addition, witness Mitchell testified that these new regulations also impose higher requirements in the areas of structural integrity standards, public disclosure, location restrictions, inspection, groundwater monitoring and cleanup for existing and new CCR ponds and landfills.

In direct testimony, Company witness McLeod testified that the enactment of the CCR Final Rule created a legal obligation to retrofit or close all inactive and existing ash ponds over a certain period, as well as to perform required monitoring, corrective action, and post-closure care activities as necessary. Witness McLeod explained that the Company recognized ARO liabilities of $385.7 million on a total system basis during the test year for financial reporting purposes in accordance with Accounting Standard Codification (ASC) 410-20 (formerly Statement of Financial Accounting Standard No. 143) related to future ash pond and landfill closure costs. Witness McLeod testified that the Company eliminates all the effects of ARO accounting pursuant to ASC 410-20 from the cost of service, including the AROs associated with the CCR Rule, in accordance with the Commission's directives in Docket No. E-22, Sub 420. Witness McLeod proposed to defer the actual North Carolina jurisdictional CCR-related cash expenditures incurred through the update period in this case (June 30, 2016) to be amortized over a three-year period commencing with rates approved in this case effective November 1, 2016.

DNCP witness McLeod further testified that the CCR Final Rule requires DNCP to close or retrofit all of its active and inactive coal ash ponds and landfills. He stated that DNCP has eight generating facilities where coal ash remediation must be performed. In his direct testimony, witness McLeod testified that DNCP spent $37.5 million during the test period and anticipated spending an additional $63.8 million through June 2016. He testified that DNCP proposes to defer its portion of the expenditures over a three-year period.

In his supplemental testimony, witness McLeod adjusted the updated January 2015 through June 2016 CCR costs to a total of $84.4 million. He testified that DNCP proposes to establish a regulatory asset in the amount of $4.3 million, North Carolina's allocable share of the CCR costs to date, and to amortize this amount over a three-year period beginning with the effective date of the rates set in this proceeding.

Public Staff witness Maness testified that the Public Staff generally agrees with the concept proposed by the Company of deferring and amortizing the costs incurred through June 30, 2016, over a multi-year period, but does not necessarily agree that this treatment is automatically mandated by the August 6, 2004, Order Allowing Utilization of Certain Accounts in Docket No. E-22, Sub 420 (2004 ARO Order). Witness Maness also disagreed with the Company's proposed three-year amortization period and instead proposed a 10-year amortization. According to witness Maness, the majority of the costs underlying the ARO liability, and thus current and future expenditures, are related to generating assets that have already been retired or are financially impaired and are soon to be retired. He testified that for costs of significant size related to retired or abandoned plants, the Public Staff in recent years has consistently recommended an amortization or levelization period of 10 years, and this period has been approved by the Commission.

In addition, Public Staff witness Maness testified regarding some of the specific CCR work being performed by DNCP, as described by DNCP in response to data requests. Witness Maness stated that four of the DNCP coal-fired facilities are closed, or have been converted to natural gas-fired facilities. At the closed facilities, remediation is taking three different forms: (1) cap and close method; (2) a clean and close method in which the coal ash is moved to an on-site pond that is being capped and closed, and the original impoundment is closed; or (3) the clean and close method, except the original impoundment is used for a new purpose. With regard to operating coal facilities, witness Maness stated that DNCP's work at this point is mainly project planning and engineering.

Witness Maness testified that the Public Staff investigated DNCP's CCR remediation efforts and found that the efforts and costs were prudent and reasonable. He stated that DNCP incurred $84.4 million in cash expenditures for CCR remediation from January 2015 through June 2016. He also provided DNCP's projected CCR costs during the next several years. That amount was filed by DNCP under seal as a confidential trade secret. Witness Maness testified that DNCP has recorded this amount, adjusted to its current fair value, as an ARO. The present amount of the ARO recorded on DNCP's financial statements is $326 million. As these costs are incurred and deferred into a regulatory asset account, that amount will be deducted from the ARO.

With respect to the ongoing deferral of CCR expenditures, witness Maness indicated that the Company plans to defer North Carolina jurisdictional CCR cash expenditures for review by the Commission in future base rate proceedings, and subsequent recovery through base non-fuel rates approved in such proceedings. Witness Maness contended, however, that it was clear from the language of the 2004 ARO Order that the Commission intended that the authorization granted by the Order would have no impact on the ratemaking treatment to be determined by the Commission. He stated that although the 2004 ARO Order could be read as applying to all AROs, it should be noted that at the time of its issuance, the only significant ARO in existence was the one established for nuclear decommissioning. At that time, the Commission already had in place a long-standing, comprehensive mechanism to provide for the tracking and recovery of nuclear decommissioning costs. Witness Maness testified that the purpose of the 2004 ARO Order was to maintain Company accounting to match the Commission’s longstanding accounting and ratemaking treatment of those costs, consistent with the statement in the ARO Order that “the intent and outcome of the deferral process shall be to continue the Commission’s currently existing accounting and ratemaking practices.” However, in the case of CCR expenditures, witness Maness testified that the Commission has not yet decided what the long-standing accounting and regulatory treatment of those costs should be. Therefore, in the absence of any action by the Commission in this case, witness Maness stated that continuing “the Commission’s currently existing accounting and ratemaking practices,” as the 2004 ARO Order requires, would most likely mean that the CCR expenditures through June 30, 2016, and afterwards, would simply be written off to expense in the year incurred. Witness Maness testified that because no prior

Commission treatment of CCR costs has been determined, the Company could not simply unilaterally presume that its proposed ratemaking deferral is authorized. Nonetheless, witness Maness testified that in this proceeding the Public Staff has investigated the CCR expenditures that the Company has proposed to defer and amortize, and has determined that the costs were reasonable and prudently incurred. Therefore, the Public Staff recommended the establishment of a regulatory asset for those expenditures.

Given the above, witness Maness made several recommendations regarding ongoing CCR deferrals:

> (1) That the Company be allowed to defer additional CCR expenditures through calendar year 2018, without prejudice to the right of any party to take issue with the special accounting treatment in a regulatory proceeding.
>
> (2) That the Commission note in its order in this proceeding that it is not making any conclusions regarding the prudence and reasonableness of the Company's overall CCR plan, or regarding any specific expenditures other than the ones it has approved for recovery in this case.
>
> (3) That the annual amortization expense approved for recovery in this proceeding continue to be credited as an offset to any future deferrals recorded by the Company, up until the time rates approved in the Company's next general rate case go into effect. Additionally, any other appropriate credits related to CCR expenditures, such as recoveries from third parties or governmental authorities, should be recorded as an offset to any future deferrals.
>
> (4) That the Company be required to file an annual report with the Commission, on the same date it files its annual FERC Form 1 report, detailing the CCR deferrals recorded in the previous calendar year as well as the annual amortization offset and any other offsets recorded.
>
> (5) That because CCR costs are being incurred due to the nature of the coal burned to produce energy over the years, the energy allocation factor be used to determine the North Carolina retail revenue requirement.

Moreover, Public Staff witness Maness testified that, during its investigation in this proceeding the Public Staff became aware that the Company has been or is involved in several legal disputes with various parties regarding its CCR compliance activities or the state of its CCR facilities. Additionally, witness Maness explained that the Company remains subject to possible state and federal findings of non-compliance with applicable statutes and regulations. Witness Maness indicated that the Public Staff has not become aware of any significant costs that have been incurred to date as a result of these disputes. Nevertheless, the Public Staff recommended that the Commission include in its order in this proceeding, in association with any approval of future deferral, a finding that any costs resulting from fines, penalties, other imprudent or unreasonable activities, or corrective actions to address those activities, are not allowable for deferral or recoverable for ratemaking purposes, and that legal costs incurred or settlements reached in resolution of disputes will be subject to close scrutiny to make sure that they are reasonable and appropriate for recovery from ratepayers.

Nucor witness Kollen testified that a three-year amortization period is unduly and unnecessarily short. Witness Kollen explained that a reasonable amortization period for the inactive and retired plants is 10 years, and a reasonable amortization period for the operating plants is the remaining life of each plant. The remaining service lives for the operating plants, according to witness Kollen, range from six to 35 years. Witness Kollen estimated an approximate amortization period based on the remaining service lives of 20 years. For the combined CCR costs of DNCP's retired and operating plants, witness Kollen proposed a 15-year amortization period for all CCR deferrals. Nucor reiterated this position in its post-hearing Brief.

In rebuttal testimony, Company witness Stevens argued that a lengthy recovery period for regulatory assets does not serve the best interests of DNCP's North Carolina customers or the Company. Since the Company is afforded a return on the unamortized balance for ratemaking purposes, witness Stevens argued that a longer amortization period costs customers more in the long run, while delaying the Company's recovery of actually incurred costs in the short run. Witness Stevens contended that delaying recovery of these actually incurred costs produces greater rate instability, and the Company's position strikes a reasonable balance of establishing rates that send accurate price signals to North Carolina customers, while recognizing the appropriate level of cost of service. The Company's proposed non-fuel base revenue increase in this proceeding, according to Stevens, is almost completely offset by a 2017 fuel factor reduction and decrement rider to refund EDIT with the total overall change in North Carolina retail rates approximating 0.2%. Witness Stevens noted that for many customer classes, their bills would reflect an overall decrease in rates on January 1, 2017.

With respect to Nucor witness Kollen's proposal to amortize CCR expenditures over 15 years, witness Stevens explained that the Company anticipates significant additional CCR expenditures subsequent to June 30, 2016, and a short duration for the amortization of this first wave of CCR expenditures is more appropriate. Witness Stevens contended that the Company's position aligns well with the fuel factor reduction and the significant EDIT refund, and setting an appropriate amortization level for this first wave of CCR expenditures allows for greater rate stability when addressing the need to recover additional phases of ongoing CCR compliance in future rate filings.

With respect to Public Staff witness Maness' proposal to amortize CCR expenditures over 10 years, witness Stevens argued that the comparison of the CCR expenditures to the abandonment or impairment and early retirement of a generating facility is neither reasonable nor accurate. Witness Stevens testified that the abandonment or impairment and retirement of a generating facility is a one-time, non-recurring event, while CCR expenditures are recurring and are environmental compliance and remediation costs, not abandoned plant, that will need to be recognized in future rate filings. According to witness Stevens, the Public Staff's proposal will likely result in overlapping vintages of CCR expenditure regulatory asset amortizations in future rate cases. To the contrary, witness Stevens explained that under the Company's proposal, the regulatory asset from the instant proceeding will conclude and be replaced by the next regulatory asset in the next general rate case, allowing for a more smooth transition from one case to the next, and more importantly, achieving greater rate stability for customers.

With respect to witness Maness' discussion regarding the Company's proposed ratemaking treatment of CCR expenditures, Company witness McLeod explained in his rebuttal testimony that the Company has set forth a ratemaking methodology for CCR expenditures in this case, and the Public Staff and other parties have the opportunity to respond. Witness McLeod testified that no one is disputing that the Commission will ultimately rule on the Company's proposed ratemaking methodology for CCR expenditures.

In addition, witness McLeod testified that the Company already requested and the Commission has already granted deferral authority for CCR expenditures in the 2004 ARO Order, and it is not necessary for the Company to request deferral authority from the Commission again for ARO costs beyond 2018 as recommended by Public Staff witness Maness. With respect to witness Maness' recommendation for the Commission to note in its order in this proceeding that it is not making any conclusions regarding the prudence or reasonableness of the Company's overall CCR plan, or regarding specific expenditures other than the ones it has approved for recovery in this case, witness McLeod argued that it is not necessary for the Commission to address future CCR expenditures in this proceeding. Further, witness McLeod disagreed with witness Maness' recommendation for the annual amortization expense approved for recovery in this proceeding continue to be credited as an offset to any future deferral recorded by the Company, up until the time rates approved in the Company's next general rate case go into effect, stating that the Company is not recovering these costs dollar for dollar, they are simply part of the total base non-fuel rate cost of service. Witness McLeod stated that it would be no more appropriate to grant witness Maness' proposal for these costs than it would for any other cost in the base non-fuel cost of service. Witness McLeod also contended that it is not necessary or appropriate for the Commission to address the future ratemaking treatment of fines, penalties, or other litigation costs in this case.

Finally, witness McLeod indicated that the Company accepted the Public Staff's adjustment to calculate the CCR expenditures regulatory asset by the energy factor.

The Stipulation includes the following provisions with respect to CCR costs:

(1) Amortization periods – CCR expenditures incurred through June 30, 2016, should be amortized over a five-year period. Notwithstanding this agreement, the Stipulating Parties further agree that the appropriate amortization period for future CCR expenditures shall be determined on a case-by-case basis.

(2) Deferral of future CCR expenditures – By virtue of the Commission's approval in this proceeding of a mechanism to provide for recovery of CCR

expenditures incurred through June 30, 2016, the Company has authority pursuant to the August 6, 2004, Order in Docket No. E-22, Sub 420, to defer additional CCR expenditures, without prejudice to the right of any party to take issue with the amount or the treatment of any deferral of ARO costs in a rate case or other appropriate proceeding.

(3) Continuing amortization and deferral of CCR expenditures – The Company and the Public Staff reserve their rights in the Company's next general rate case to argue to the Commission (a) how the unamortized balance of deferred CCR expenditures incurred by the Company prior to June 30, 2016, and the related amortization expense should be addressed; and (b) how reasonable and prudent CCR expenditures incurred by the Company after June 30, 2016, should be recovered in rates.

(4) Overall prudence of CCR Plan – The Public Staff's agreement in this proceeding to the deferral and amortization of CCR expenditures incurred through June 30, 2016, shall not be construed as a recommendation that the Commission reach any conclusions regarding the prudence and reasonableness of the Company's overall CCR plan, or regarding any specific expenditures other than the ones to be recovered in this case.

(5) Reporting - The Company shall file with the Commission, on the same date it files its quarterly ES-1 report, a report detailing 1) the CCR deferrals recorded in the reporting period, and 2) regulatory accounting entries pursuant to the August 6, 2004, Order in Docket No. E-22, Sub 420, with regard to any costs other than nuclear decommissioning costs or CCR costs, recorded in the reporting period.

(6) That DNCP agrees to provide the Public Staff, within 90 days of the date of the Stipulation, with a presentation regarding its accounting practices for non-nuclear asset retirement obligation costs.

At the hearing, witness Maness testified that the Stipulating Parties had reached agreement as to the CCR issues set forth in his testimony. He also stated that the Company and Public Staff agreed that it was not necessary for the Commission to make any findings regarding the possible future treatment of fines, penalties, or other litigation costs in this proceeding.

Further, witness Maness testified that the Public Staff's general impression is that DNCP's CCR repository facilities "were constructed and operated in a similar manner to facilities in various areas in the country." (T Vol. 8, at p. 361) In addition, witness Maness elaborated on the Public Staff's investigation of DNCP's CCR remediation efforts. He testified that the effort thus far has been engineering studies for work to be performed at the various sites, and beginning the closure of existing impoundments, such as dewatering of CCRs and water treatment. Witness Maness further testified that the Public Staff's Engineering Division reviewed invoices for the CCR work performed by DNCP and did not find any of the costs to be unreasonable.

On November 16, 2016, the Attorney General's Office (AGO) filed a post-hearing Brief. The AGO takes the position that the proposed recovery of coal ash expenditures unfairly burdens consumers and should be rejected by the Commission. The AGO notes that the Commission must set rates that are fair to the ratepayers and utility, pursuant to G.S. 62-133(a), and that the burden of proof is on the utility, under G.S. 62-75. The AGO further states that the Commission should consider, among other things, whether the CCR costs incurred are reasonable and prudent, and that this determination is detailed and fact specific, especially in the context of complicated cost recovery for environment-related clean-up costs. In addition, the AGO states that DNCP's CCR costs are projected to increase significantly over the next two or three years.

Moreover, the AGO contends that DNCP's CCR expenditures do not relate to operations that are used and useful for DNCP's current customers because they are for the disposal of CCRs that were produced over decades at plants that no longer generate electricity. Further, the AGO maintains that DNCP's proposal to include the unamortized balance of CCR costs in DNCP's rate base and earn a return on the unamortized balance is not a fair or lawful burden to impose on ratepayers, and is contrary to the holding in <u>State ex rel. Utilities Comm’n. v. Carolina Water Service</u>, 335 N.C. 493, 439 S.E.2d 127 (1994).

In addition, the AGO asserts that DNCP failed to provide detailed evidence about whether the CCR remediation costs it seeks to recover are reasonable and prudent, and that the Public Staff’s analysis was insufficient. According to the AGO, DNCP appears to simply rely on compliance with the CCR Final Rule to justify its recovery of costs. The AGO also points out that DNCP has been sued for alleged violations of CCR environmental regulations.

Discussion and Decision

<u>Prudence and Reasonableness</u>

In the Coal Ash Management Act of 2014, the General Assembly included a moratorium prohibiting the Commission from allowing CCR clean-up costs in a utility’s base rates. The moratorium was in effect until January 15, 2015. However, that section also states that “Nothing in this section prohibits the utility from seeking, nor prohibits the Commission from authorizing under its existing authority, a deferral for costs related to coal ash combustion residual surface impoundments.” G.S. 62-133.13.

DNCP, like many electric utilities in the United States, has for decades generated electricity by burning coal. During those decades, the widely accepted reasonable and prudent method for handling CCRs has been to place them in coal ash landfills or ponds (repositories). At the hearing in this docket, in response to questions by the Commission, DNCP witness Stevens testified that when the EPA issued its draft CCR Rule in December 2014, DNCP first began addressing the fact that its CCRs could not remain stored in their existing repositories in perpetuity. Further, as discussed above, in his direct testimony, DNCP witness McLeod testified that the CCR Final Rule requires DNCP to close or retrofit all of its active and inactive CCR repositories. He further testified that

DNCP spent $37.5 million during the test year and anticipated spending an additional $63.8 million through June 2016. He later filed supplemental testimony adjusting the updated January 2015 through June 2016 CCR costs to a total of $84.4 million.

Public Staff witness Maness testified that the Public Staff's general impression is that DNCP constructed and operated its CCR repositories in a manner that is similar to CCR facilities in various areas of the United States. He stated that four of the eight DNCP coal-fired facilities are closed, or have been converted to natural gas-fired facilities. At the closed facilities, DNCP is using three methods in its effort to comply with the CCR Final Rule: (1) cap and close method; (2) a clean and close method in which the coal ash is moved to an on-site pond that is being capped and closed, and the original repository is closed; or (3) the clean and close method, except the original repository is used for a new purpose. He described the efforts as engineering work at various facilities, and the beginning of closure work at some facilities, including dewatering of the ash ponds and water treatment. Witness Maness also testified that the Public Staff Engineering Division reviewed the invoices for the CCR work that has been performed by DNCP thus far, and that the Public Staff did not find that any of DNCP’s CCR costs were unreasonable. Witness Maness testified that the Public Staff found that DNCP's efforts and costs expended were prudent and reasonable.

Based on the allocation methodology agreed upon in the Stipulation, DNCP's allocable share of the CCR costs is $4,417,000. The Stipulating Parties agreed to DNCP's requested deferral of these costs and an amortization period of five years.

The Commission finds the CCR testimony of DNCP witnesses Stevens and McLeod and Public Staff witness Maness to be credible and to constitute substantial evidence that DNCP's actions in planning and beginning the work for permanent CCR repositories have been prudent, and that the CCR remediation costs incurred thus far by DNCP are reasonable. In particular, the Commission gives substantial weight to Public Staff witness Maness's testimony describing the Public Staff’s investigation of DNCP’s CCR remediation efforts. Witness Maness testified in some detail regarding the three CCR remediation options being employed by DNCP. He also testified that the Public Staff found that DNCP's CCR remediation efforts and costs were prudent and reasonable.

The AGO takes issue with the probative value of the DNCP and Public Staff evidence in support of CCR remediation costs recovery, not with the absence of such evidence. As outlined in detail above, the record contains substantial, unrebutted evidence from DNCP and Public Staff witnesses that DNCP’s CCR remediation expenditures at issue were reasonable and prudent. The AGO has offered no witness or other probative evidence that DNCP’s incurrence of CCR remediation costs were imprudent or unreasonable. No witness offered evidence that the costs should not be recovered. The only material dispute among the witnesses was over the appropriate amortization period for deferred remediation costs.

The AGO contends that DNCP's CCR activities have not produced property that is used and useful for DNCP's ratepayers. The Commission does not agree and determines that the used and useful argument misses the point. The AGO’s argument is based on the fact that some of the coal-fired generating plants producing CCRs were no longer in service or were converted to gas-fired generation or some of the coal ash repositories had been closed before the test year. The Commission finds the AGO's logic misplaced. Due to federal and state environmental regulations, and in an attempt to remediate potential environmental degradation, DNCP incurred expense in the test year as extended. The fact that some of the coal-fired plants from which the CCRs had been removed were no longer in service or that the repositories in which the CCRS were stored had been closed and no longer receiving CCRs is beside the point. The issue is not recovery of costs of closed plants or costs of storing CCRs in repositories over past periods. The issue is recovery of remediation costs incurred in the test year as extended. In addition, a number of the electric generating plants from which CCRs are being and have been produced and the repositories are still in operation and have not been taken off line or closed.

Moreover, the current CCR repositories are and have served their purpose of storing CCRs for many years. In that respect, they have been used and useful for DNCP's ratepayers. However, pursuant to the CCR Final Rule, DNCP must incur expenses to the existing repositories for environmental remediation. As a result, the required solution for the CCR remediation serves the public policy of encouraging and promoting harmony between public utilities, their users and the environment. See G.S. 62-2(a)(5). Based on the testimony of witnesses Stevens, McLeod, and Maness, DNCP is responding to the CCR Final Rule requirements in a responsible and prudent manner. The result of DNCP's efforts should be the expenditure of funds to establish permanent CCR storage repositories. Like the existing CCR repositories, these permanent storage repositories will be used and useful for DNCP's ratepayers.

Further, the Supreme Court's decision in Carolina Water Service, cited by the AGO, does not support a denial of rate base treatment for the deferred and unamortized test year costs of CCR remediation. In Carolina Water Service, the Commission allowed the utility to include in the utility's rate base the unamortized portion of net costs still on the books at time of retirement not charged off in the test year for its Mt. Carmel wastewater treatment plant, even though the plant was not operating at the end of the test year and would never again be in service. The Commission's rationale was that the Mt. Carmel wastewater treatment plant unrecovered net costs should be treated as an extraordinary property retirement, with the deferred and unamortized costs included in the utility's rate base. The Supreme Court reversed that portion of the Commission's Order. The Court stated:

> [C]osts for abandoned property may be recovered as operating expenses through amortization, but a return on the investment may not be recovered by including the unamortized portion of the property in rate base.

Carolina Water Service, 335 N.C., at 508, 439 S.E.2d, at 142.

The issue in Carolina Water Service was whether to include in rate base the unamortized, unrecovered costs of a wastewater treatment plant that had been placed in service many years ago at which time the costs of the plant were incurred but with respect to plant that had been permanently retired. As addressed above, the costs at issue in this case are test year remediation costs, not unamortized costs of abandoned plants. Whatever costs DNCP incurred in past years in coal-fired generating plants already removed from service or costs incurred in the past to store CCRs in repositories now closed are not costs DNCP seeks to recover as DNCP's CCR remediation costs.

If, hypothetically, the Court had determined that costs Carolina Water Service had incurred in the test year to remediate potential environmental degradation from a discontinued wastewater treatment plant could be amortized but that the unamortized costs could not be included in rate base, perhaps such precedent would support the AGO's position; however, such costs are not those the Court addressed.

Although four of the coal-fired generating plants that are the sites of DNCP's CCR remediation efforts are no longer generating electricity, DNCP is not seeking to defer undepreciated costs of these plants or inclusion of unamortized costs in rate base as part of its CCR cost recovery request. Also, the existing CCR repositories at these sites cannot be abandoned by DNCP. Unlike the abandoned Mt. Carmel wastewater treatment plant in Carolina Water Service, the existing CCR repositories continue to be used and useful for storing CCRs, and will continue to be used and useful until DNCP moves the CCRs to a permanent repository, or takes the necessary steps to cap and close the existing repository.

The Commission's determination for allowing a portion of test year CCR costs to be recovered in this case is beneficial to DNCP, and the decision to amortize a large percentage of these test year CCR costs over a five-year period is a benefit to the ratepayer. The Commission likewise finds reasonable the provisions of the Stipulation allowing a return on the unamortized balance over the five-year period to be fair to the Company. Further, the Commission deems appropriate the establishment of a regulatory asset through which future CCR costs are accounted for, and thereby potentially departing from the general rule of matching future annual costs with revenues in the same period. In this fashion, the Company will have the opportunity to seek cost recovery for this unexpected and extraordinary cost expended in response to the CCR Final Rule which has required DNCP to store CCRs in a manner different from that in which the CCRs were being stored prior to 2015. The cost of complying with federal and state CCR remediation requirements was a risk that was unknown to the Company prior to 2015. Absent deferral, failure to recover those future costs could materially impact the Company's earnings. The Company's actions and testimony, and the testimony of Public Staff witness Maness, provide justification for the Commission's decisions. No witness testified against the effort to treat future CCR remediation costs as a regulatory asset for deferral and consideration in a future rate case. Based upon the entire evidence of record, the present Stipulation to allow the test year CCR costs to be recovered in this case by amortization over a five-year period with the unamortized balance to earn a return and the authorization to treat future CCR costs incurred through 2018 as a regulatory asset (which is the mechanism to facilitate the deferral of future CCR costs) is proper and in the public interest under the facts and circumstances of this case.

Conclusions on CCR Cost Deferral

Based on the foregoing and the record, the Commission finds and concludes that DNCP shall be allowed to defer the costs of its remediation of coal combustion residuals through June 30, 2016, and shall be allowed to amortize those deferred costs over a period of five years. The Company submitted substantial evidence that its costs incurred to comply with federal and state law regarding disposal of CCRs were prudently and reasonably incurred. No other party presented conflicting direct evidence on prudence or reasonableness of these costs. However, the Commission's approval of DNCP's CCR cost deferral is based on the particular facts and circumstances presented in this docket and, therefore, is not precedent for the treatment of CCR costs in any future proceedings.

In addition, the Commission finds and concludes that the treatment of CCR costs incurred by DNCP after June 30, 2016, shall be reviewed in a future rate case, subject to the provisions of the Stipulation regarding future amortization periods, deferral of future CCR expenditures, continuing amortization and deferral of CCR expenditures, and any other arguments or positions presented by the Company, the Public Staff, or another party at that time. Further, the Commission's determination in this case shall not be construed as determining the prudence and reasonableness of the Company's overall CCR plan, or the prudence and reasonableness of any specific CCR expenditures other than the ones deferred and authorized to be recovered in this case.

Finally, the Commission finds reasonable the provisions of the Stipulation regarding the agreement of DNCP to make a presentation to the Public Staff regarding its accounting practices for non-nuclear asset retirement obligation costs.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 19-23

The evidence supporting these findings of fact and conclusions is contained in the filings and Orders in Docket Nos. E-22, Sub 519, and Sub 533, the Company's verified Application, the direct and rebuttal testimony and exhibits of Company witnesses McLeod and Stevens, the testimony of Public Staff witness Fernald and Nucor witness Kollen, the Stipulation, and the entire record in this proceeding.

Warren County CC and Brunswick County CC Deferrals

The Company's initial Application proposed to amortize the deferred costs, including a return on investment, associated with the Warren County CC requested in the Company's petition in Docket No. E-22, Sub 519. [7] As explained by Company witness

[7] The Commission previously addressed the deferral costs related to the Warren County CC. On January 30, 2015, DNCP filed an application for an accounting order in Docket No. E-22, Sub 519 (Sub 519 docket) requesting that it be allowed to defer certain costs associated with its Warren County CC generating facility that was placed in service in December 2014. After comments by the parties and an oral argument held on June 15, 2015, the Commission issued an Order Denying Deferral Accounting for Warren County CC on March 29, 2016. DNCP filed for reconsideration regarding the deferral of the Warren County CC on March 3, 2016 (Motion for Reconsideration). On May 17, 2016, the Commission issued an Order

McLeod, DNCP requested to defer the incremental costs incurred from the time the assets were placed into service (December 2014) until the time they are reflected in the base non-fuel rates, and that these cost be amortized over a three-year period, with the unamortized balance, net of ADIT, included in rate base.

The initial Application also proposed to amortize the deferred costs, including a return on investment, associated with the Brunswick County CC requested in the Sub 533 docket, from the time the assets were placed into service (April 2016) until the time they are reflected in base non-fuel rates, and that these costs be amortized over a three-year period.

Public Staff witness Fernald testified that DNCP filed additional evidence concerning the Sub 519 docket. She stated that had DNCP filed this additional evidence concerning its December 2014 ES-1 information as part of its original deferral application, the Public Staff's position on the original deferral request would have changed. Witness Fernald further testified that while the Public Staff does not agree with all of the Company's additional adjustments to the December 2014 ES-1 included in its Motion for Reconsideration, the Public Staff would have agreed with the Company's proposed adjustment to apply the 2014 cost of service study factors to the December 2014 ES-1. Witness Fernald stated that with this adjustment, the ROE would have been materially below the Company's authorized ROE, and the Public Staff would not have opposed the Company's deferral request based on earnings. Therefore, Public Staff witness Fernald recommended that the Warren County CC deferral costs of $10,204,000 for North Carolina retail be recovered from ratepayers in this proceeding through a levelized amortization over a three-year period.

Nucor witness Kollen recommended that the Commission deny DNCP's proposed regulatory deferrals associated with the Warren County CC and Brunswick County CC. With respect to the Warren County CC deferral, witness Kollen discussed the Order Denying Deferral Accounting for Warren County Combined Cycle Generating Facility issued on March 29, 2016, in Docket No. E-22, Sub 519, in which the Commission denied the Company's deferral request. Witness Kollen noted the Commission subsequently agreed to rehearing on the issue in the instant proceeding.

According to witness Kollen, the Company's requests sought deferral of costs only through June 30, 2016. He argued that since that date now has passed, an accounting order issued after June 30, 2016, necessarily would authorize retroactive ratemaking.

Nucor witness Kollen noted that the Company did not seek to return to customers savings from the ODI implemented earlier in 2016. The Company proposes to recover increases in its costs (i.e. the Warren County CC deferral request), while at the same time

consolidating the Motion for reconsideration for the Warren County CC deferral with the general rate case application filed in this docket. The Order also consolidated the Deferral Request for the Brunswick County CC, which was filed in Docket No. E-22 Sub 533 (Sub 533 docket) into the general rate case docket as well.

retain reductions in its costs. These proposals, according to witness Kollen, are inconsistent and inequitable.

Additionally, witness Kollen testified that any deferrals authorized for 2015 cannot and will not be recorded in 2015 and will not affect the Company's earnings in 2015, as the Company's accounting books now are closed and final for 2015. He stated that the ROE effect of the Brunswick County CC costs is approximately 0.08%, all else being equal, or approximately two months of the effect of Warren County CC. This is not material, according to witness Kollen, even if the Company is not earning its authorized return and does not meet this basic test applied by the Commission in the Warren County CC and other deferral proceedings. Nucor witness Kollen, therefore, recommended that the Commission reject the Company's request to defer and amortize these post-commercial operation costs.

In the event that the Commission authorizes deferral of these costs, witness Kollen recommended that the Commission levelize or annuitize the revenue requirement effect over a 10-year amortization period to include a return on and recovery of the regulatory asset. He testified that the post-commercial operation costs are analogous to "start-up costs" that could be amortized over the life of the unit. Witness Kollen argued that the Company's proposed three-year amortization period is unduly short and unnecessarily increases the revenue requirement compared to a longer amortization period.

In rebuttal testimony, Company witness Stevens testified that it is important for the Commission to fully assess a utility's request for deferral accounting with the evidence on the financial condition and earned return of the utility in question, as well as the impact that an extraordinary event has on that earned return and financial condition. In response to witness Kollen's testimony regarding the Commission's prior denial of the Warren County CC deferral request, witness Stevens contended that the extensive and detailed evidence presented in the Company's May 3, 2016, Motion for Reconsideration, filed in Docket No. E-22, Sub 519, demonstrates that DNCP's earned return for the 2015 test year was 5.99%. Witness Stevens testified that the financial impact of placing the Warren County CC in service is also significant and meets the Commission's well-established standard for deferral authorization, especially given the substantial fuel savings derived from the operation of the generation asset for the benefit of North Carolina customers, including Nucor, on a timely and current basis. With respect to witness Kollen's assertion that the effect of the Brunswick County CC deferral request only amounts to eight basis (.08%) points ROE, witness Stevens referenced the evidence in the Company's Application for Dominion North Carolina Power for an Accounting Order for the Brunswick County CC (Docket No. E-22, Sub 533), asserting that there was a 31 basis points net detrimental impact to the Company's annualized earned return under existing tariffs. This was benchmarked against the Company's fully adjusted test period North Carolina jurisdictional ROE of 5.06%, when all components for regulatory accounting purposes are properly taken into account.

With respect to Nucor witness Kollen's comparison of the Warren County CC and Brunswick County CC deferrals with a proposed deferral associated with the savings from

ODI, witness Stevens testified that the Company has reflected a full going-level of ODI savings in the base non-fuel revenue requirement in this proceeding. Witness Stevens explained that it has been this Commission's practice to approve accounting deferrals sparingly based on its well-established standard of whether a significant and unusual or extraordinary event has occurred that has materially impacted a utility's earnings and overall financial condition. The ODI program was a narrow severance program targeted at certain management layers in the organization – it would not qualify as an issue ripe for deferral given its relatively small impact. Witness Stevens stated that in the Commission's recent denial of the Public Staff's request for deferral accounting associated with a modest increase in annualized revenues resulting from the Company's January 1, 2015, extension of the agreement for electric service with Nucor (Docket No. E-22, Sub 517), the Commission noted that deferral is only warranted where an event affecting the utility's costs or revenues is unusual or extraordinary because changes in revenues, expenses, and investments happen routinely between the time a utility's rates are fixed by the Commission and the time of the next rate case and routine changes alone do not result in a change in the balance of revenues, expenses, and investments struck by the Commission's last rate Order. According to witness Stevens, the ODI program savings are not extraordinary and of such material financial significance to warrant deferral accounting consideration.

With respect to Nucor witness Kollen's proposed 10-year recovery period for the Warren County CC and Brunswick County CC deferrals, witness Stevens argued against such an extended period for the same reasons he generally disagrees with extended recovery periods for other regulatory assets in this proceeding. According to witness Stevens, North Carolina customers have also been receiving substantial fuel expense savings on a timely and current basis through the fuel factor as a direct result of the Warren County CC and Brunswick County CC investments, and it is not appropriate to substantially delay the recovery of the costs incurred that resulted in the fuel savings. Witness Stevens contended that the Commission has generally authorized a shorter time period for the amortization of deferrals associated with new major generation facilities placed into service by North Carolina electric utilities, and DNCP is not aware of the Commission using a 10-year recovery period in recent cases. Witness Stevens added that the Public Staff has agreed with the Company's proposed three-year amortization period in this case.

The Stipulation provides for deferral accounting treatment and recovery of deferred post-in-service costs for both the Warren County CC and the Brunswick County CC. The Stipulation provides that the deferred costs will be recovered over a three-year period on a levelized basis.

The issue before the Commission in this case is one of cost deferral, a recognized practice allowing recovery of unusual expenses arising from extraordinary circumstances or events; and its use, which the Commission has historically employed sparingly, does not constitute impermissible retroactive ratemaking. The Commission has established relatively clear guideposts and standards over the years for determining when a petition for deferral is appropriate. This is especially the case in the context of major new generating facilities that also create material fuel cost savings that are flowed through to ratepayers through lower fuel rates. Based upon the evidence now before the Commission, the Commission finds that DNCP has made the requisite showing that the Warren County CC and Brunswick County CC costs in question had a material impact on the Company's financial condition. As shown in the Company's Motion for Reconsideration in Docket No. E-22, Sub 519, the Company's verified Application in this case, and the testimony of Public Staff witness Fernald, the Commission also recognizes that DNCP's earnings were well below its authorized cost of equity of 10.2% when both the Warren County CC and Brunswick County CC were placed in service. Much of the evidence presented by the Company in this case, relating to its earnings at the time the Warren County CC went into service, was not presented as evidence before the Commission at the time the Commission issued its initial order of March 29, 2016, in Docket No. E-22, Sub 519, denying the Company's request for deferral of the post-in-service costs of the Warren County CC.

In consideration of the foregoing, the Commission finds and concludes that DNCP's requests to defer post-in-service costs of the Warren County CC and the Brunswick County CC should be and are hereby granted. The Commission further finds that the evidence in the record does not support Nucor witness Kollen's view that the ODI program savings are sufficiently extraordinary and of such material financial significance to warrant deferral accounting consideration. The Commission finds and concludes that for the present case deferral and recovery of the Warren County CC and Brunswick County CC deferred post-in-service costs presented in the Stipulation is just and reasonable to all parties in light of all the evidence presented.

Regulatory Assets and Liabilities with Amortization Ending in 2017

Public Staff witness Fernald identified the following regulatory assets and liabilities that will be fully amortized in 2017:

Regulatory Asset or Liability	Amortization Ends On
Unrecovered design basis costs – Surry	May 31, 2017
NUG buyout costs – Atlantic	May 31, 2017
DOE settlement	June 30, 2017
Bear Garden deferral	October 31, 2017
NUG buyout costs – Mecklenburg	October 31, 2017

Witness Fernald recommended that the unamortized balances of these regulatory assets and liabilities as of October 31, 2016 (the date the Company proposed to implement the provisional rates in this proceeding), be re-amortized over three years using a levelized amortization, consistent with her recommended treatment of the EDIT liability and deferred costs.

Company witness McLeod discussed several concerns with Public Staff witness Fernald's proposal. First, witness McLeod testified that the amortization periods for these regulatory deferrals were established by the Commission in prior cases based on the specific facts and circumstances in those cases. Second, the Public Staff's adjustment, according to witness McLeod, would result in an adjustment to rates in this case based on events scheduled beyond the close of the hearing date in this proceeding. Witness McLeod also contended that it is not appropriate to convert to a levelization approach for the treatment of regulatory assets and liabilities midstream, as this will result in either an over- or under-recovery of carrying costs on the deferral balance over the life of the asset.

The Stipulation amortizes the unamortized balances of these regulatory assets and liabilities as of October 31, 2016, based on the date the provisional rates were expected to be implemented in this proceeding, over three years using a levelized amortization, as proposed by Public Staff witness Fernald. The Commission finds and concludes that for the present case the stipulated treatment of these unamortized balances is just and reasonable to all parties in light of all the evidence presented.

<u>Beyond Design Basis Study Regulatory Assets</u>

Public Staff witness Fernald testified that the Company has included in other additions in this proceeding two regulatory assets related to costs incurred to perform studies at the Surry and North Anna nuclear plants as required by the Nuclear Regulatory Commission (NRC) as a result of the disaster at the Fukushima nuclear plant following an earthquake and tsunami in Japan. Witness Fernald proposed to exclude these two regulatory assets from rate base and instead include the expenses related to these NRC studies incurred in 2015 in O&M expenses in this proceeding. Witness Fernald noted that the Company did not file a request with the Commission to defer the cost of these studies. Public Staff witness Fernald commented that the Commission previously stated in prior DNCP rate case orders that it does not consider a deferral period, an amortization period, or a window for filing a deferral request to be open-ended.

In rebuttal testimony, Company witness McLeod argued that DNCP's accounting methodology for the beyond design basis study costs is consistent with the treatment of design basis documentation costs incurred in the late 1980s and early 1990s. Witness McLeod explained that at that time, the Company requested and received guidance from the FERC for design basis documentation costs incurred, and that the FERC instructed the Company to record the costs to FERC Account 182.2 (regulatory asset account), and that these costs have been included in the Company's cost of service studies in North Carolina for over two decades.

Witness McLeod testified that since these costs were mandated by the NRC, and the Company deferred them to FERC Account 182.2 in accordance with FERC's instructions, it would be improper to account for them as other O&M expenses as recommended by the Public Staff. Witness McLeod represented that the Company will make diligent efforts to seek the Commission's approval on a timelier basis in the future.

The Stipulation provides for deferral accounting treatment of the beyond design basis study costs mandated by the NRC as proposed by Company witness McLeod. The Stipulation also provides that the Company will comply with Commission Rule R8-27(a)(2) prior to establishing any regulatory assets and liabilities for North Carolina jurisdictional purposes in the future. The Commission hereby approves deferral accounting treatment for the beyond design basis study costs *nunc pro tunc* as of July 2012, which is the date the Company began deferring these costs. The Commission finds and concludes that recovery of the beyond design documentation study costs as presented in the Stipulation is just and reasonable to all parties in light of all the evidence presented.

Chesapeake Decommissioning and Closure Costs Regulatory Asset

In its Application, DNCP proposed to include any decommissioning and closure costs incurred at Chesapeake and to amortize such deferred costs as of June 30, 2016, across a three-year recovery period.

Nucor witness Kollen testified that the Company deferred the costs for dismantling and other site costs for Chesapeake, but did not offset those costs by the savings in O&M expense, other operating expenses, and depreciation expense. According to witness Kollen, these expenses were included in the revenue requirement in the 2012 Rate Case, and the Company will continue to collect these expenses through the revenue requirement until rates are reset at the conclusion of this proceeding, even though they no longer are incurred. Witness Kollen asserted that Nucor had requested that the Company quantify the savings since the retirement of the plant, and the Company did not do so and simply responded that the proposed regulatory asset does not include any offsets for avoided operating expenses after the facility was retired.

Witness Kollen recommended that the Commission deny the Company's request for recovery of the deferral unless DNCP can demonstrate that the costs exceed the savings until rates are reset in this proceeding. Alternatively, if the Company provides an appropriate quantification of the savings from the avoided operating expenses (realized since closure of the plant in late 2014), then the Commission should calculate the revenue requirement on the deferred cost net of the savings on a levelized basis using a 10-year amortization period.

In response to Nucor witness Kollen, Company witness Stevens noted there were no operating O&M or depreciation expenses associated with Chesapeake in the Company's 2015 test year cost of service study. The only O&M expenses are those related to closure costs incurred in the 2015 test year. Witness Stevens contended that the cost avoidance of retiring Chesapeake Units 1-4 should also be reflected in Nucor's evaluation. In the 2012 Rate Case, the Company presented information that demonstrated that to comply with the Mercury Air Toxics Standard rules it was expected that Chesapeake Units 1-4 would all require Dry Flue-Gas Desulfurization equipment by 2015. In addition, witness Stevens testified that these units would require other new environmental equipment to comply with other expected environmental rules such as CSAPR, Ozone Standard Review, NAAQS, and 316(b). Witness Stevens presented an analysis showing the net present value cost increase in lieu of retirement totaled over $190 million for these four coal units.

Witness Stevens additionally testified that the purported savings on O&M and depreciation expenses previously incurred at Chesapeake did not create a windfall for the Company that can now retroactively be captured, as Nucor witness Kollen contends. Witness Stevens contended that no further adjustments are necessary because the environmental cost avoidance well exceeded the assumed savings and certainly caused no over-recovery of DNCP's cost of service during this period.

With respect to Nucor witness Kollen's proposed 10-year recovery period for the Chesapeake decommissioning and closure cost deferral, witness Stevens argued against such an extended period for the same reasons he generally disagreed with extended recovery periods for regulatory assets. Witness Stevens noted that the Public Staff agreed with the Company's proposed three-year amortization period and that this is also consistent with prior Commission treatment of regulatory assets.

The Stipulation provides for deferral accounting treatment of the Chesapeake closure costs regulatory asset and recovery over a three-year period on a levelized basis. The Commission does not findNucor's reasoning persuasive and, therefore it declines to adopt Nucor's recommendations in this matter. Rather, the Commission agrees with the deferral treatment as specified in the Stipulation. The Commission finds and concludes that recovery of the Chesapeake closure costs as presented in the Stipulation is just and reasonable to all parties in light of all the evidence presented and should be adopted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 24

The evidence supporting this finding of fact and these conclusions is contained in the testimony of Public Staff witness Maness and DNCP witness McLeod.

Public Staff witness Maness addressed the question of how revenues received by DNCP for CCR cost deferrals after the approved amortization period should be treated. Witness Maness testified that DNCP appears to interpret prior Commission orders to allow CCR cost deferral to continue automatically after the approved amortization period and for an indefinite period into the future. He stated that the Public Staff disagrees with DNCP's interpretation and recommends that the Commission allow deferral to continue through 2018, subject to prudency and reasonableness reviews, and subject to a credit of the approved CCR expense to future deferrals until DNCP's next general rate case.

In his rebuttal testimony, DNCP witness McLeod disagreed with the Public Staff's recommendation that the annual amortization cost should continue to be credited to DNCP's deferred CCR costs until the Company's next general rate case. Witness McLeod opined that the deferred CCR costs should be treated as any other cost of service expense being recovered in the Company's non-fuel base rates.

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

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 25

The evidence supporting this finding of fact and these conclusions is contained in the testimony of Public Staff witness Fernald, the rebuttal testimony of Company witness Stevens, the Stipulation, and the entire record of this proceeding.

In her testimony, Public Staff witness Fernald made three accounting recommendations. The first recommendation related to the Yorktown Plant. Witness Fernald urged that upon the closure of the Yorktown plant, should DNCP plan to amortize Yorktown’s net book value and closure costs (other than those relating to the closure of coal ash ponds, for North Carolina ratemaking purposes), that DNCP should notify the Commission of the closure and also provide the Commission with an estimate of the net book value and closure costs.

Witness Fernald’s second recommendation related to the FERC USOA. She stated that under Commission Rule R8-27, the FERC USOA is prescribed for all electric utilities under the jurisdiction of the Commission. Witness Fernald noted that DNCP does not maintain its accounting system based on the FERC USOA, but instead uses a different system of accounts, which it refers to as natural accounts. Public Staff witness Fernald explained that in order to comply with the Commission’s requirements and produce its financials and reports based on the FERC USOA, DNCP maintains a module to convert its natural account postings to FERC accounts.

Witness Fernald testified that the FERC USOA identifies and categorizes costs in a manner that is consistent with ratemaking and identifies costs that are of particular interest to regulators. If a company does not maintain its accounting system based on the FERC USOA, it must still be able to produce records based on the FERC USOA, to a level such that an audit trail is maintained. Witness Fernald noted that during the Public Staff's investigation, there were several instances where costs could not be audited based on the FERC USOA. Based on that, Public Staff witness Fernald recommended that the Company maintain its accounting records in a manner such that it is able to produce records based on the FERC USOA – including allocations from its affiliates such as the service company charges discussed below – so that an audit trail is maintained and fluctuations based on the FERC USOA can be explained. Witness Fernald further recommended that the Company file the procedures and processes that it will implement to improve the transparency between the FERC accounts and the natural accounts with the Commission within 90 days after issuance of the Order in this proceeding.

Witness Fernald's third recommendation related to service company charges. Each month, when DNCP is billed by its affiliated service company, Dominion Resources Services, Inc. (DRS), for (1) services performed by DRS personnel and (2) third-party bills paid by DRS and allocated to DNCP, the expenses allocated to DNCP are initially mapped to FERC Account 923 - Outside Services Employed. Witness Fernald explained that the Company has an automated program that then takes the amounts billed by DRS to DNCP each month and reclassifies items to different accounts as may be appropriate.

Witness Fernald testified that during the Public Staff's investigation, DNCP was unable to provide the specific transactions billed by DRS to DNCP by FERC account. The Company's accounting records should be maintained such that the details of the transactions billed by DRS to DNCP, including the amounts allocated for third-party bills by vendor and the FERC account to which they are charged, is available. Finally, witness Fernald recommended that the Company file the procedures and processes that it will implement to comply with this recommendation with the Commission within 90 days after the date of the Order in this proceeding.

With respect to the Public Staff's accounting recommendation regarding the Yorktown Plant, Company witness Stevens avowed that the Company would notify the Commission when the Yorktown closure occurs and provide an estimate of the undepreciated value of Yorktown at the time of closure and the estimated level of costs to be incurred for closure.

With respect to the Public Staff's second recommendation pertaining to the FERC USOA, Company witness Stevens indicated that the Public Staff applied no materiality threshold when making such statements and that the Company views its accounting practices as reasonable and appropriate.

In response to the Public Staff's generalized comment about improving transparency between FERC accounts and natural accounts, Company witness Stevens attested that the Company filed its Application for a revised Services Agreement between DRS and DNCP with the Commission on September 23, 2016. Witness Stevens reiterated the Company's commitment to provide the Public Staff with information in Docket Nos. E-22, Subs 476, 477, and 482, which will help to address the Public Staff's issues and concerns.

The Stipulation includes the following provisions addressing Public Staff witness Fernald's accounting recommendations:

> (1) The Company will notify the Commission when the Yorktown Power Station closure occurs and provide estimates of its undepreciated value at the time of closure and the level of costs to be incurred for closure.
>
> (2) The Public Staff's accounting recommendations concerning the FERC USOA and the service company charges will be addressed in Docket Nos. E-22, Subs 476, 477, and 482.

The Commission finds and concludes that the three accounting recommendations as detailed by Public Staff witness Fernald and agreed to by the Company in the Stipulation are appropriate and should be accepted. The Commission further finds and concludes that provisions set forth in the Stipulation as agreed to between the Company, the Public Staff and CIGFUR I are just and reasonable to all parties in light of all the evidence presented.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 26-28

The evidence supporting these findings of fact and conclusions is contained in the Application, the direct testimony and exhibits of Company witnesses Petrie, Haynes and Hupp, the supplemental testimony and exhibits of Company witnesses Petrie and Haynes, the testimony and exhibits of Public Staff witnesses Peedin and Lucas, the Stipulation, and the entire record in this proceeding.

In his direct testimony, witness Petrie presented an estimate of DNCP's adjusted system fuel expense for the period July 1, 2015 – June 30, 2016, of $1.689 billion, which was used by witness Haynes to estimate the anticipated reduction in the fuel factor rate. He also estimated the deferred fuel balance as of June 30, 2016, and described DNCP's forecasted fuel expense recoveries for the second half of 2016. In his supplemental testimony, witness Petrie presented an updated adjusted total system fuel expense for the 12-month period ending June 30, 2016, of $1.74 billion, as shown in the Company's August 5, 2016 fuel factor adjustment filing in Docket No. E-22, Sub 534. He noted that this total adjusted amount was calculated based on the 100% Marketer Percentage proposed by witness Hupp in his direct testimony. Witness Petrie also testified that the Company's projected fuel over-recovery at the end of December 2016, assuming an interim rate change on November 1, 2016, was approximately $3.9 million.

In his direct testimony, Company witness Haynes used a placeholder base fuel rate based on the fuel factor approved in the Company's 2015 fuel adjustment case, Docket No. E-22, Sub 526. In his supplemental testimony, witness Haynes used the updated adjusted total system fuel expense presented by witness Petrie to calculate an average base fuel factor of $0.02116/kWh, a reduction from the current base fuel factor of $0.02427/kWh. He also used the revised Rider A rate of zero consistent with the Company's 2016 fuel adjustment filing. He further testified to the Company's reintroduction of Rider A1 on November 1, 2016, for the purpose of accelerating the return of DNCP's fuel over-recovery to its customers in conjunction with placing the proposed updated non-fuel and base fuel rates into effect on a temporary basis on that date. He explained that implementation of Rider A1 will lower the estimated over-recovery balance as of December 31, 2016, and reduce further the impact of the proposed base rate increase.

In his direct testimony, Company witness Hupp presented the Company's recommendation that the Marketer Percentage applicable to DNCP be increased from 85%, as it was established in the Company's 2012 Rate Case and used in DNCP's 2015 fuel factor case, Docket No. E-22, Sub 526, to 100%. He testified that this increase would result in a more appropriate treatment of purchased power costs, because it would permit DNCP to recover all of its prudently incurred purchased power costs through fuel rates. He explained that, when DNCP purchases rather than self-generates power, it does so in order to minimize the cost incurred to meet its customers' energy requirements. As a result, the resulting cost of DNCP's market energy purchases will likely be less than the variable marginal cost of running one of the Company's own generators to meet the energy need. Witness Hupp also testified that the Company believes that any prudently incurred power purchases made to serve customers' energy requirements should be fully allowable through fuel. He stated that the variable costs of running one of the Company's generators largely represent allowable fuel costs deemed recoverable by the Commission in the Company's fuel factor cases. Therefore, witness Hupp stated, purchases of energy deemed to be less expensive than this marginal and allowable cost of fuel for fleet operations should – when shown to be prudently incurred – also be fully allowable through fuel with no impacts to base rates. He testified that this would better align the Company's recoverable fuel-related expenses with its actual costs.

Witness Hupp noted that the Company's request for relief of the PJM Order conditions, addressed below with regard to Finding of Fact No. 50, removes the barrier that the Commission identified in its order in DNCP's 2014 fuel clause adjustment proceeding as preventing the Commission from using the discretion provided at subsection (f) to permit DNCP to recover 100% of its purchased power costs through fuel, including deemed congestion related costs.

Public Staff witness Peedin testified that with respect to purchased power, DNCP is entitled under G.S. 62-133.2(a3) to recover only "the fuel cost component, as may be modified by the Commission, of electric power purchases identified in subdivision (4) of subsection (a1)," and the fuel cost component of other purchased power, through the prospective fuel factor and the EMF. She testified that the Public Staff interprets the phrase "fuel cost component, as modified by the Commission" to mean that, in DNCP's case, the fuel cost component of purchases subject to economic dispatch must be determined by the Commission when the actual cost is not known, and that the Commission may modify the method for making that determination as appropriate. She stated that allowing DNCP to recover all of the energy costs of purchased power through a Marketer Percentage of 100% appears to read this phrase out of the statute and implies that the energy costs consist solely of fuel costs. She opined that is not the case, stating that a significant portion of energy costs consist of non-fuel variable operation and maintenance expenses.

Witness Peedin recommended that the Commission adopt a Marketer Percentage of 78% to be used as a proxy for the fuel cost component of purchases for which the actual fuel cost is unknown. She stated that both methods used by the Public Staff to determine this Marketer Percentage were proposed by DNCP in its 2008 fuel proceeding, Docket No. E-22, Sub 451, as an alternative to the off-system sales method then used by DEC and DEP. Witness Peedin described the first methodology as a review of data from the 2014 and 2015 PJM State of the Market reports, which identified each fuel component of the cost of energy used to set the energy market price. She stated that according to these reports, the fuel components of energy cost for years 2014 and 2015 were both 73.90%. She described the second methodology as a review of data provided by DNCP that blended the Company's internal data with PJM State of the Market report data for the DOM Zone. She stated that the average of the 2014 and 2015 values under the two methods was 78%. Based on her recommended Marketer Percentage of 78%, witness Peedin further recommended an adjustment to DNCP's non-fuel purchased power energy expense so that 22% of that expense would flow through base rates as purchased energy costs. This resulted in an adjustment to increase the base non-fuel rates by $2.261 million and decrease fuel rates by the same amount.

The Stipulation provides for a base fuel factor of $ 0.02073/kWh, as differentiated between customer classes, as shown on Company Rebuttal Exhibit PBH-1, Schedule 9. The Stipulation also provides that the appropriate EMF to be included in DNCP's updated annual fuel factor for the 2017 rate year shall be determined by Commission order in the Company's 2016 fuel case, Docket No. E-22, Sub 534.

The Stipulation also provides for a Marketer Percentage of 78%, to remain in place until the Company's next base rate application or its 2018 fuel factor application, whichever occurs first.

No party opposed the stipulated base fuel factor or the stipulated Marketer Percentage or conducted cross-examination on these issues at the hearing.

Based on all of the evidence in this proceeding, the Commission finds and concludes that the stipulated base fuel factor of $0.02073/kWh is just and reasonable for DNCP in this case. The Commission also concludes that a marketer percentage of 78%, to be applied to appropriately determine the fuel cost component of energy purchased for which the fuel cost is unknown, should continue to be used until the Company's next base rate application or the Company's 2018 application to adjust its annual fuel factor, whichever occurs first.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 29

The evidence supporting this finding of fact and these conclusions is contained in the Application, the direct, supplemental, and rebuttal testimony and exhibits of Company witness Chapman, the direct and settlement testimony and exhibits of Public Staff witness Hinton, the direct testimony and exhibits of Nucor witness Woolridge and CUCA witness O'Donnell, the Stipulation and the hearing testimony of witness Chapman.

In the Application, and as explained by DNCP witness Chapman in his direct testimony, the Company proposed a capital structure reflecting long-term debt of 46.641% and common equity of 53.359%. Witness Chapman, who is Senior Vice President – Mergers and Acquisitions and Treasurer for the Company, testified that the appropriate capital structure for use in this case was the Company's actual capital structure as of December 31, 2015. He discussed the Company's significant capital needs going forward, and explained how the Company plans to finance those capital needs, based on a balance of debt and common equity that DNCP believes will support the Company's credit ratings going forward, and continue to enable the Company to access a number of markets, under a wide range of economic environments, on reasonable terms and conditions. He stated that this market access is critical to fund the ongoing infrastructure capital expenditure program that will be necessary to meet the Company's public service obligations in North Carolina and throughout its system. In his supplemental testimony, witness Chapman updated the Company's proposed capital structure to its actual structure as of June 30, 2016, which reflected a long-term debt component of 46.080% and an equity component of 53.920%. Based on the Company's proposed cost rates for long-term debt and common equity, witness Chapman's proposed capital structure produced an overall weighted-average cost of capital of 7.803%.

Public Staff witness Hinton initially filed testimony stating that the Company's proposed common equity ratio produces an overall return on rate base greater than necessary to maintain credit quality and continue to attract capital. Witness Hinton noted that DRI's announced acquisition of Questar Corporation (Questar) led to an S&P credit downgrade for DRI and its subsidiaries, including VEPCO, from A- to BBB+. He noted that the credit rating reports indicate that VEPCO's regulated operations have lower business risk than DRI's unregulated businesses. He opined that the Questar acquisition may contribute to an already high debt ratio for DRI. He also noted that it is too early to tell whether recent actions, in particular the Questar acquisition, pose a risk that will increase the cost of capital.

Witness Hinton referred to DRI's confidential target capital structure for the Company as support for his position on capital structure. In addition, he noted that although the Company's average equity ratio from November 2009 to March 2016 was 54.01%, in contrast the common equity ratio averaged 49.97% for the six-year period prior to November 2009. He referenced testimony submitted in a Virginia State Corporation Commission proceeding regarding the Company operating with an equity ratio at the upper end of its target range, and opined that the increase in the equity ratio in recent years is not necessary for reasonable financing or justified in terms of its impact on Company customers. He also stated that DRI has a much higher debt ratio and lower equity ratio than the Company, and asserted that the Company's ratepayers were being asked to pay a high equity ratio to help offset DRI's high debt ratio. Finally, he stated his concern about the effect of added earnings from Virginia's return on equity incentives on the Company's capital structure. Witness Hinton concluded by recommending a capital structure consisting of 50.96% common equity and 49.04% long-term debt. Witness Hinton based his recommended capital structure on data from Regulatory Research and Associates, Inc., on recently commission approved equity ratios for other vertically integrated electric utilities with comparable Standard & Poor (S&P) bond ratings between BBB+ and A-. He accepted the Company's proposed long-term debt cost rate of 4.645%.

Nucor witness Woolridge testified that DNCP's proposed capital structure includes more equity and less debt than other electric utilities, does not include short-term debt, which amounts to almost 10% of its capitalization as of December 31, 2015, and includes much less equity than the capitalization of DNCP's parent DRI. He testified that the median common equity ratios of his and witness Hevert's proxy groups are 47.1% and 48.2%, respectively, and that DNCP's proposed capitalization includes more equity and less financial risk than these averages. Witness Woolridge, like Public Staff witness Hinton, noted concerns with the use of double leverage where the regulated utility subsidiary finances equity with the use of debt raised through the parent company. Witness Woolridge also compared DNCP's capitalization as of December 31, 2015, comprised of 9.81% short term debt, 41.20% long term debt, and 48.99% common equity, to that of DRI, comprised of 13.03% short term debt, 56.61% long-term debt, and 30.36% common equity. He noted that he used utility holding companies in his proxy group because their common stock is traded in the markets, and their financial risk and equity ratios are thus relevant for comparison rather than those of operating utilities. He testified that a high equity ratio will have a downward impact on a utility's financial risk, and that the ROE should be adjusted to account for that. He stated that based on these factors he proposed a capital structure consisting of 50% long-term debt and 50% common equity. He asserted that this capital structure is more in line with the average common equity ratios approved by state regulatory commissions in electric utility rate cases in 2015 and 2016 than the Company's proposed structure. Witness Woodridge adopted the Company's proposed long-term debt cost rate of 4.65%.

CUCA witness O'Donnell testified that DNCP's proposed capital structure is not comparable to the average common equity ratio of companies in witness Hevert's comparable group nor similar to the average equity ratio granted by state regulators for electric utilities in 2015 and to-date in 2016. He stated that the average common equity ratio for witness Hevert's comparable group is 50.1%. He stated further that the average common equity ratio granted to electric utilities by regulators across the United States in 2015 was 48.86% and to-date in 2016 is 43.67%. He noted that, in 2016, excluding limited issue rider cases, there have been only five rate case decisions and two of those were made in states that use non-investor sources of capital in the regulatory capital structures. Witness O'Donnell's calculation of the common equity ratio for those two companies was 49.47%. He noted further that DRI's common equity ratio as of December 31, 2015 was 34.9%. He concluded that DNCP's requested capital structure is not representative of capital structures of utility holding companies or of operating companies. He recommended a capital structure consisting of 50% common equity and 50% long-term debt, with a weighted debt cost rate of 4.89%. He justified this recommendation as being well above the DRI equity ratio, approximately equal to the equity ratio of witness Hevert's comparable group, and slightly above the average equity ratio granted to electric utilities by state regulators across the country in 2016.

In his rebuttal testimony, witness Chapman testified that the capital structures recommended by witness Hinton (50.96% common equity, 49.04% long-term debt), Witness Woolridge and witness O'Donnell (both 50% common equity, 50% long-term debt) were not reasonable, as they ignored the Company's actual capital structure as of June 30, 2016, as well as DNCP's actual capital structure at year-end of the each of the previous three years. He stated that the actual capital structure is the relevant structure for this case because it is the structure that supports DNCP's target credit ratings, which in turn allows DNCP to attract debt investment at an attractive cost basis. He noted that the equity component of DNCP's actual capital structure as of June 30, 2016 is in line with the equity component of the Company's year-end capital structure for the previous three years as well as to the forecasted capital structure as of December 31, 2016. He disagreed with these witnesses' reliance, without further justification, on proxy groups for their capital structure recommendations, due to the difficulty of determining a truly comparable capital structure within a proxy group of peer utilities that operate in different regulatory jurisdictions.

With regard to these witnesses' comparison of the Company's proposed capital structure to that of DRI, witness Chapman stated that development of the Company's financing plan is done with the objective of maintaining the current credit ratings of the Company, not those of DRI. He stated that a similar but separate analysis is undertaken at the DRI level, which accounts for financing needs of other, non-VEPCO subsidiaries in addition to the Company. He testified that claims that the DRI capital structure is relevant for purposes of this case are unfounded, and that VEPCO ratepayers are not being singled out and asked to pay more to offset DRI's higher debt ratio. He explained that all of DRI's subsidiaries support the parent company's debt capital structure.

Witness Chapman also addressed the impact of DRI's acquisition of Questar on VEPCO's cost of capital, stating that S&P's downgrade of the entire Dominion family due to the acquisition announcement had no discernible impact on VEPCO's cost of debt. He also stated that this one "consolidated" or "family" credit rating change should not adversely impact VEPCO's cost of debt, noting the unchanged "indicator" rating for VEPCO that S&P published along with its downgraded consolidated rating. Finally, in response to arguments concerning the increase in DNCP's common equity ratio in recent years, he stated that the higher equity component that the Company has experienced since 2009 supports using the capital structure that the Company proposed in this proceeding. He stated that the actual equity ratio is appropriate as it offsets the construction risk that an equity investor would experience during a period of heavy capital spending such as the one the Company is currently undertaking. Finally, he explained that witness Hinton's concern regarding Virginia's return on equity incentives is overstated, because it has a negligible impact on DNCP's retained earnings account, and because witness Hinton did not recognize other recent events that had a significant downward impact on the Company's retained earnings.

Following settlement negotiations between DNCP, the Public Staff, and CIGFUR I, as reflected in Section II.B of the Stipulation, the Stipulating Parties proposed a capital structure of 51.75% common equity and 48.25% long-term debt. The Stipulating Parties agreed to use 4.650% for the cost of long-term debt, based on a correction that was presented in witness Chapman's rebuttal testimony and that was not challenged by any party.

In his stipulation testimony, witness Hinton testified that the capital structure reflected in the Stipulation represents a compromise by both parties in an effort to reach agreement. He accepted the change in the long-term debt cost rate from the originally proposed debt cost rate. He noted that the stipulated 51.75% equity ratio is 217 basis points lower than the Company's request, 125 basis points lower than currently authorized for DEC and DEP, 79 basis points higher than his earlier recommendation, and 75 basis points higher than the Commission-authorized equity ratio in the last two DNCP rate cases. He stated that he believes the end result of the settlement is fair and reasonable with respect to both ratepayers and shareholders, and that customers will benefit from lower rates as a result of a negotiated settlement that, if approved, will reduce the Company's proposed rate increase by over $12 million. He also noted the $400,000 to be paid by DNCP shareholders to assist low-income customers.

At the hearing in this case, witness Chapman noted as part of his summary of his testimony that, while the equity component of the stipulated capital structure is below that reflected in the Company's actual capital structure as of June 30, 2016, his opinion is that the stipulated capital structure and overall weighted average return will still allow the Company to access capital markets on reasonable terms in order to secure the capital required to make the significant investments DNCP is planning and will, therefore, benefit the Company's North Carolina customers. No party cross-examined witness Chapman at the hearing.

In its post-hearing Brief, CUCA contends that the Commission should adopt witness O'Donnell's recommendation of a 50% equity and 50% debt capital structure. Similarly, the Attorney General's Office (AGO) states that the evidence supports a capital structure that uses an equity ratio of 50% or less. To support its argument, the AGO largely relies on the testimony of witness Woolridge concerning the median equity ratio of his proxy risk group, the median equity of witness Hevert's proxy group, and the lower equity ratio of DNCP's parent company, DRI, including short-term debt. Nucor's post-hearing Brief, likewise, proposes a capital structure consisting of 50% common equity and 50% long-term debt, relying on the testimonies of witnesses Hinton, Woolridge, and O'Donnell concerning the average equity ratios of various proxy groups and the average of equity ratios approved in electric rate cases by state commissions over various periods of time. The Commission concludes that such comparisons may be relevant and of some interest, but are entitled to minimal weight in determining the appropriate capital structure for DNCP for ratemaking purposes. Instead, the Commission gives substantial weight to the rebuttal testimony of DNCP witness Chapman. He testified that it is difficult to determine a truly comparable capital structure for a proxy group of utilities that operate in different regulatory jurisdictions because not all regulatory jurisdictions define capital structure in the same manner. Some jurisdictions include and/or exclude different balance sheet items, such as short-term debt, income tax items, customer deposits, etc. For example, he contended that the average equity ratio of witness Hinton's peer group is 51.89% when calculated in a manner consistent with DNCP's proposed capital structure in this case. In addition, as noted above, witness Woolridge's proxy group used utility holding companies while DNCP is a subsidiary operating company. Finally, also important is that the mean, median, and range of equity ratios vary for different proxy groups and, therefore, the witnesses use their own discretion in arriving at their recommended capital structures after considering such comparisons.

With regard to comparisons to DRI's capital structure, witness Chapman testified that DNCPs financing plan is developed with the objective of maintaining the current credit ratings of DNCP, not those of DRI. He stated that a similar but separate analysis is undertaken at the DRI level, which accounts for financing needs of DRI's other subsidiaries, in addition to DNCP. Witness Chapman stated that all of DRI's subsidiaries support the parent company's debt capital structure.

The Commission must consider all of the evidence and exercise its independent judgment in determining the appropriate capital structure for DNCP in the context of setting DNCP's rates. The Commission gives substantial weight to Company witness Chapman's testimony regarding the Company's effort to find the appropriate balance between equity and debt financing. As witness Chapman noted, witness Woolridge and witness O'Donnell rely primarily on the averages of their respective proxy groups without providing any further rationale in support of their recommended capitalization ratios.

The Commission is also persuaded by the fact, as noted in the stipulation testimony of Public Staff witness Hinton, that the stipulated 51.75% equity ratio is 217 basis points lower than the Company's request, 125 basis points lower than currently authorized for DEC and DEP, 79 basis points higher than his earlier recommendation, and 75 basis points higher than the Commission-authorized equity ratio in the last two DNCP rate cases. The Commission places substantial weight as well on witness Hinton's conclusion that the end result of the settlement is fair and reasonable with respect to both ratepayers and shareholders, and that customers will benefit from lower rates as a result of a negotiated settlement that, if approved, will reduce the Company's proposed rate increase by over $12 million.

The Commission accords substantial weight to the stipulation testimony of witness Hinton, and finds that an equity ratio of 51.75% represents an appropriate reduction from the Company's actual ratio, for purposes of reducing the amount of higher cost equity financing to be borne by ratepayers in this case. Based upon the evidence described above and the record in this docket as a whole, the Commission finds and concludes that the stipulated capital structure and costs of long-term are fair and reasonable, and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 30-34

The evidence supporting these findings of fact and conclusions is contained in the Application, the direct, rebuttal, and stipulation testimony and exhibits of Company witnesses Curtis and Hevert, the pre-filed direct and settlement testimony and exhibits of Public Staff witness Hinton, the pre-filed direct testimony and exhibits of Nucor witness Woolridge and CUCA witness O'Donnell, the Stipulation, and the hearing testimony.

Based upon the evidence and legal analysis set forth below, the Commission concludes, based on its own independent analysis, that the stipulated rate of return on common equity of 9.90% proposed in the Stipulation in this proceeding and the resulting stipulated overall rate of return on rate base of 7.367% are just, reasonable, and fair to the Company, its shareholders and its customers and that such rates of return are fully consistent with the requirements of North Carolina law governing the establishment of public utility rates of overall return and returns on common equity.

Summary of the Evidence on Return

DNCP's existing allowed rate of return on common equity, established by the Commission in 2012 in Docket No. E-22, Sub 479, is 10.2%.[8] Its existing approved overall rate of return on rate base is 7.80%.[9] In its Application, DNCP proposed that the allowed rate of return on common equity in this proceeding be established at 10.5%. This proposed rate of return on common equity, in conjunction with the other elements of the Company's proposed capital structure, resulted in a proposed overall rate of return on rate base for the Company of 7.88%. Based on the capital structure updated to June 30, 2016, the 10.5% ROE recommended by witness Hevert, and a cost of long-term debt revised to 4.650% in witness Chapman's rebuttal testimony, the Company's final proposal for the overall rate of return was 7.805% prior to the Stipulation.

DNCP's original rate of return request was supported by the direct testimony and exhibits of DNCP witnesses Curtis and Hevert. Witness Curtis, who is Vice President – Technical Solutions for Virginia Electric and Power Company, testified to the significant capital investment needs facing the Company. He stated that in order to attract the capital needed to meet these substantial future capital needs, the Company must achieve an adequate authorized ROE in this proceeding, and that the 10.5% ROE proposed by DNCP will allow the Company to attract capital on reasonable terms in the still-volatile and highly competitive capital markets. He explained that the ability to attract capital on favorable terms is important to DNCP's ability to maintain its current credit ratings and, ultimately, minimize the cost of capital for customers. An adequate return also ensures DNCP's ability to commit capital to future construction projects to provide safe, reliable, and cost-effective electric service to North Carolina customers without eroding the Company's shareholders' interests. In witness Curtis' supplemental testimony, he stated that as of June 30, 2016, the

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[8] See 2012 Rate Order; 2015 Remand Order.

[9] Id.

Company's fully-adjusted earned rate of return on equity capital for the update period was only 5.50%, far below the Company's currently-authorized 10.2%.

Witness Hevert served as DNCP's primary cost of equity witness. Witness Hevert filed direct testimony and nine exhibits in support of DNCP's request for a 10.5% return on equity. He explained that the cost of equity is the return that investors require to make an equity investment in a company, that it should reflect the return that investors require in light of the subject company's risks and the returns available on comparable investments, and that it differs from the cost of debt because it is neither directly observable nor a contractual obligation.

Witness Hevert's direct testimony and exhibits document the specific analyses he conducted in support of DNCP's rate filing and provide a detailed description of the results of his analyses and resulting cost of equity recommendations. He applied the Constant Growth and Multi-Stage forms of the DCF model, the CAPM, and the Bond Yield Plus Risk Premium approach to develop his ROE recommendation.

Witness Hevert testified that a return that is adequate to attract capital on reasonable terms enables the utility to provide service while maintaining its financial integrity, and that the utility's return should be commensurate with the returns expected elsewhere in the market for investments of equivalent risk. He stated that the Commission's decision should result in providing DNCP with the opportunity to earn an ROE that is: (1) adequate to attract capital at reasonable terms; (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on investments in enterprises having corresponding risks. He discussed the need to select a group of proxy companies to determine the cost of equity, and how he selected the proxy group for this case.

According to witness Hevert, the results of his Constant Growth DCF analysis produced a range of 8.33% to 10.01% ROE, the results of his Multi-Stage DCF analysis were a range of 9.40% to 10.09%, and the results of his Multi-Stage DCF analysis that used the current proxy group P/E ratio to calculate the terminal value was a range of 9.34% to 10.91%. The results of witness Hevert's CAPM analysis showed a range of 8.69% to 11.64%. The results of his Bond Yield Risk Premium analysis indicated an ROE range from 10.04% to 10.47%. In his rebuttal testimony, witness Hevert updated his results to show an ROE range of 8.14% to 9.32% for his Constant Growth DCF analysis, a range of 8.85% to 9.97% for his Multi-Stage DCF analysis, a range of 8.87% to 11.22% for his CAPM analysis, and a range of 10.02% to 10.38% for his Bond Yield Risk Premium analysis. Based on his analyses, witness Hevert concluded that a rate of return on common equity in the range of 10.25% to 10.75% represents the range of equity investors' required ROE for investment in integrated electric utilities in today's capital markets. Within that range, he recommended an ROE for DNCP of 10.5% in both his direct and rebuttal testimony.

Witness Hevert explained that his ROE recommendation also took into consideration several additional factors, including (1) DNCP's planned investment program, (2) the risks associated with environmental regulations, (3) the regulatory environment in which DNCP operates, (4) flotation costs, and (5) the increased uncertainty in the capital markets. With regard to the regulatory environment, he noted that North Carolina is generally considered to be a constructive regulatory jurisdiction, and that authorized ROEs tend to be correlated with the degree of regulatory supportiveness (utilities in jurisdictions considered to be more supportive tend to be authorized somewhat higher returns). He did not, however, make any specific adjustment to his ROE estimates for the effect of these factors.

Witness Hevert also considered the economic conditions in North Carolina in arriving at his ROE recommendation. He noted that the rate of unemployment has fallen substantially in North Carolina and the U.S. generally since late 2009 and early 2010, with December 2015 rates of 5.60% in the State. He noted that since the Company's last general rate filing in March 2012, unemployment in the counties served by DNCP has fallen by over 4 percentage points. He explained further that while at its peak in 2009 into early 2010, the unemployment rate in those counties reached 13.41% (1.41 percentage points higher than the statewide average), by December 2015 it had fallen to approximately 7.30% (1.80 percentage points higher than the statewide average). He summarized that although it remains higher than the national and State averages, it has fallen considerably since its peak in early 2010. Witness Hevert also noted that since 2013, the State has consistently exceeded the national rate for real gross domestic product growth, and that since 2009, median household income in North Carolina has grown at a somewhat faster annual rate than the national median income. In addition, total personal income, disposable income, personal consumption, and wages and salaries were generally on an increasing trend. Finally, he noted that since 2005, residential electricity costs in North Carolina remain approximately 13% below the national average. Based on all of these factors, witness Hevert opined that North Carolina and the counties contained within DNCP's service area continue to steadily emerge from the economic downturn that prevailed during the Company's previous rate case, and have experienced significant economic improvement during the last several years that is projected to continue. In his opinion, DNCP's proposed ROE is fair and reasonable to DNCP, its shareholders and its customers, in light of the impact of changing economic conditions on DNCP's customers.

Witness Hevert also addressed the capital market environment, and testified that the current market is one in which it is important to consider a broad range of data and models when determining the cost of equity.

Witness Chapman stated that granting the Company an authorized return of 10.5% on common equity will allow DNCP to compete in the capital markets and to raise equity and debt at reasonable rates. He testified that authorizing the Company's requested return on common equity will allow DNCP to carry out its responsibility to provide reliable services at affordable cost and is fundamental to the Company's ability to maintain a strong credit profile, and that the ability to access capital markets on reasonable terms will reduce DNCP's borrowing cost for the benefit of the customers.

Public Staff witness Hinton testified that current economic conditions are characterized by continued low inflation rates and the reduction in long-term interest rates, particularly the decrease in treasury yields since December 2012 (the time of the DNCP's last general rate case). He further opined that continued low inflation rates have led to lower expected returns in the equity markets, which he supported by recent articles denoting that investors should expect lower rates of return. Witness Hinton used the DCF model, the Regression Analysis of Allowed Returns on Equity for electric utilities, and the Comparable Earnings method as his primary methods for determining the appropriate cost of common equity. He also used the CAPM as a check on those primary methods. For his DCF and comparable earnings analyses, witness Hinton estimated DNCP's cost of equity capital by reference to a group of proxy companies. The results of his analyses were a range of 8.30% to 9.30% for the DCF method, a single estimate of 9.49% for the Regression Analysis, and a range of 9.00% to 9.80% for the Comparable Earnings method. Corrections submitted in his settlement testimony changed his DCF range to 8.40% to 9.40%, and his Comparable Earnings range to 9.03% to 9.87%, but did not change his recommended ROE for DNCP. The result of his CAPM analysis was an estimated ROE of 8.00%, which witness Hinton used as a secondary check on his other results. Witness Hinton also performed tests for the reasonableness of his recommendation: (1) his recommended capital structure and cost rates for debt and equity yielded a pre-tax interest coverage ratio of 4.3 times, and (2) for other electric utilities he identified the average approved rate of return on equity as 9.52% in the first six months of 2016 and 9.60% for all of 2015, excluding Virginia cases that added incentive points to the cost of capital in certain cases. He concluded that a reasonable range of DNCP's cost of equity is between 8.80% and 9.80%, and recommended an ROE for this case of 9.30%. Witness Hinton also recommended an overall cost of capital of 7.02%.

Witness Hinton also testified with regard to changing economic conditions noting that North Carolina Department of Commerce and Bureau of Economic Analysis data show relatively faster growth in per capita income for DNCP's service area compared to the State as a whole, for the 2000 through 2015 period. He noted that the unemployment rate for counties in the Company's service area has fallen from 10.4% in April 2013 to 6.7% as of April 2016. He concluded that while this part of the State has a relatively poor economy, these data indicate that economic conditions facing DNCP ratepayers as a whole have been improving since DNCP's last rate case.

Witness Hinton also critiqued witness Hevert's exclusive use of earnings per share forecasts to estimate the growth component of the DCF. He questioned as unrealistic the use of a 13.65% expected investment return on the S&P 500 in witness Hevert's CAPM analysis. He also questioned witness Hevert's argument that the Company's business risks deserve special consideration. Witness Hinton testified against any risk adjustment due to the Company's projected level of capital expenditures, its level of coal generation, and compliance with the Clean Power Plan, which he believed were risks already factored into return requirements by investors and did not deserve any special recognition or consideration.

Nucor witness Woolridge recommended an ROE of 8.60%, which is near the upper end of the range based on his DCF and CAPM analyses. He applied the constant growth version of the DCF method and the CAPM methods to a proxy group of publicly held electric utilities. He relied primarily on his DCF analysis, as he believes it provides the best measure of public utility equity cost rates. Witness Woolridge concluded that the appropriate equity cost rate for companies in his and witness Hevert's proxy groups is in the 7.90% to 8.75% range. He acknowledged that his recommendation is below the average authorized ROEs for electric utility companies.

Witness Woolridge also offered a critique of witness Hevert's ROE recommendation. He asserted with regard to capital market conditions that the forecasts of higher interest rates that witness Hevert used his CAPM and Risk premium analysis are incorrect. He questioned the inputs to witness Hevert's DCF analysis, in particular, his exclusive use of earnings per share forecasts; he disagreed with the low weight that witness Hevert gave his constant-growth DCF results; and he disagreed with witness Hevert's claim that high price-earnings (P/E) ratios can lead to low DCF results. He stated that the projected interest rates and market or equity risk premiums in witness Hevert's CAPM and risk premium approaches are excessive and not reflective of current and prospective market fundamentals. Finally, he disagreed with witness Hevert's inclusion of a flotation cost adjustment to the ROE.

CUCA witness O'Donnell did not conduct his own DCF or other method of determining the appropriate ROE in this case, citing the late entry to the case by CUCA. Rather, he revised the values included in witness Hevert's analyses to correct errors he perceived in those analyses, and, based on those adjustments, recommended an ROE of 9.0% out of a range of 8.50% to 9.50% and, together with his recommended capital structure discussed above, an overall cost of capital of 6.94%. Witness O'Donnell disagreed with the long-term growth rate witness Hevert used for his multi-stage DCF analysis, and with witness Hevert's testimony that, when constant growth DCF results are below the past returns authorized by regulators the validity of the constant growth DCF model is questionable. Witness O'Donnell also disagreed with witness Hevert's explanation of why it is reasonable to focus on different methodologies given the differences in financial markets over time. Witness O'Donnell opined that the expected market return that witness Hevert used for his CAPM and risk premium analyses is not reasonable, and asserted that the Company's requested ROE in this case is related to, but inconsistent with, its pension expense request. He also referenced a September 2, 2015 Order by the Missouri Public Service Commission where that commission found that witness Hevert's CAPM and Risk Premium model resulted in inflated results and his constant growth and multi-stage DCF models are based on excessively high growth rates. Witness O'Donnell presented a graph of allowed ROEs by state regulators across the country over the past 15 years and he noted that in 2016 no electric utility has been granted an ROE in excess of 10%.

In his rebuttal testimony, witness Hevert addressed witness Hinton's analyses with respect primarily to the issues of composition and selection of the proxy group, the growth rates and dividend yields applied in the constant growth DCF model, the application of the Regression Model of Allowed Returns, the reasonableness of the Comparable Earnings method, the application of the CAPM, the relevance of flotation costs in determining the Company's cost of equity, and the business risk of DNCP relative to the proxy group.

Witness Hevert also addressed witness Woolridge's testimony, and explained why the results of witness Woolridge's analyses are not reasonable estimates of the Company's cost of equity. Witness Hevert explained how several aspects of witness Woolridge's DCF analyses and conclusions are not compatible with market conditions and are inconsistent with the practical interpretation of the models' results. Witness Hevert also showed that the growth rates that witness Woolridge asserts are overstated by historical standards represent approximately the 50th to 51st percentile of the actual capital appreciation rates observed from 1926 to 2015. He noted that from January 2014 through September 16, 2016, no utility commission had authorized a return as low as 8.60%, which is Witness Woolridge's recommendation in this case. He also noted Witness Woolridge's recognition that his recommendation is below the average for authorized ROEs for electric utilities, and that the lowest authorized ROE for a vertically integrated electric utility since January 2014 was 70 basis points above witness Woolridge's 8.60%. Witness Hevert also disagreed with witness Woolridge's assertions regarding market/book ratios and the cost of equity and provided updated data in support of that position. Finally, he testified in response to witness Woolridge's proxy group selection and expanded on his position regarding flotation costs.

In his rebuttal to witness O'Donnell's testimony, witness Hevert reiterated that all models are subject to limiting assumptions that may not be valid under certain market conditions, and that it is important to consider the results of multiple methods when estimating the cost of equity. He stated that this position is consistent with the Hope and Bluefield findings that it is the analytical result, as opposed to the methodology, that controls in arriving at ROE determinations. He stated further that a reasonable ROE estimate appropriately considers alternative methodologies and the reasonableness of their individual and collective results in light of the specific case at hand. He explained that capital market conditions influence the application and interpretation of ROE models, because the cost of equity is not directly observable and must be estimated using analytical techniques that rely on market-based data to quantify investor expectations and requirements. Specifically with regard to the constant-growth DCF model, witness Hevert explained that he gave the results of that model less weight in this case for two reasons. First, while one of the limiting assumptions of this model is that the P/E ratio will remain constant over time, the proxy group average P/E ratio had recently been trading at an unusual level relative to the overall market's P/E ratio, and since the date of the analysis he presented in direct testimony had been quite unstable. Second, constant-growth DCF model results recently have been well below the returns authorized for other vertically integrated electric utilities. Witness Hevert also addressed each of witness O'Donnell's contentions regarding the consistency of witness Hevert's ROE analysis as compared to his past analyses, and testified that those contentions are misplaced and should be given little weight.

Witness Hevert also testified that witness O'Donnell provided no testimony as to the reasonableness of the multi-stage DCF model or its application in this proceeding other than with respect to the long-term growth rate, and testified further as to the reasonableness of that rate. Witness Hevert also addressed witness O'Donnell's contentions as to the expected market return and other aspects of his CAPM and risk premium analyses. With respect to witness O'Donnell's contentions regarding the Company's pension fund's expected returns, witness Hevert testified that pension funding expectations should not be viewed as a measure of investors' required return, as the two are developed in separate manners and are used for different purposes.

Finally, in his rebuttal witness Hevert updated his analysis of economic conditions in North Carolina and DNCP's service area and testified that it continues to be his view that on balance, economic data regarding North Carolina and the U.S. do not alter his cost of equity estimates, or his recommendations, one way or the other. He also noted the importance of keeping in mind that the models used to estimate the cost of equity reflect capital markets and, therefore, general economic conditions. He stated that, given that changes in economic conditions in North Carolina are related to the domestic economy, it is reasonable to conclude that both are reflected in ROE estimates.

As reflected in Section II.B of the Stipulation, the Stipulating Parties agreed to an ROE of 9.90%. In the same Section, the Stipulating Parties also agreed that DNCP should be allowed to earn an overall rate of return on its rate base of 7.367%.

The overall return on rate base and the proposed allowed rate of return on common equity set forth in the Stipulation were supported by the stipulation testimony of DNCP witnesses Curtis and Hevert and Public Staff witness Hinton, and the hearing testimony of witness Hevert.

Witness Curtis testified that the Stipulation, including the stipulated 9.90% ROE, successfully strikes the balance of the Company's need for rate relief with the impact of that rate relief on customers.

Witness Hevert testified that although the stipulated ROE is somewhat below the lower bound of his recommended range (10.25%), he recognizes that the Stipulation represents the give-and-take among the Stipulating Parties regarding multiple, otherwise contested issues. He stated his understanding that the Company has determined that the Stipulation terms, taken as a whole, are such that it will be able to raise the external capital required to continue the investments required to provide safe and reliable service when needed at reasonable cost rates, and he appreciates and respects that determination. While his position remains that a range of 10.25% to 10.75% would represent a reasonable and appropriate measure of DNCP's cost of equity in a fully litigated proceeding, he stated that he recognizes the benefits associated with the decision to enter into the Stipulation and as such it is his view that the 9.90% stipulated ROE is a reasonable resolution of an otherwise-contested issue. Witness Hevert also testified that North Carolina falls in the top one-third of jurisdictions in terms of being a constructive regulatory jurisdiction according to RRA, and reiterated the importance of the perception of constructive regulatory environment to ratings agencies. He stated that the stipulated ROE is a reasonable outcome based on its being within three basis points of the average return of 9.87% (and seven basis points of the median) authorized for vertically integrated electric utilities from 2013 through 2016. He also stated that of the 77 cases decided during that period, 35 included authorized returns of 9.90% or higher. He also noted that the stipulated ROE falls 21 basis points below the average (and 30 basis points below the median) authorized ROE during the 2013-2016 time period for jurisdictions that are comparable to North Carolina's constructive regulatory environment and that from that perspective, the stipulated ROE is a somewhat conservative measure of the Company's cost of equity. Finally, witness Hevert testified that on balance, the impact of changing economic conditions data discussed in his direct and rebuttal testimony do not alter his ROE estimates or recommendation, and also do not alter his support of the Company's decision to agree to the stipulated ROE.

Witness Hinton supported the Stipulation as it relates to the cost of equity capital to be used in setting rates in this case, and made several changes and corrections to his direct testimony that did not alter his pre-settlement 9.3% ROE recommendation. He observed that the stipulated 9.90% ROE is higher than his recommended range of 8.80% to 9.80%, and lower than the Company's recommended range of 10.25% to 10.75%. He testified that the 9.90% represents a reasonable middle ground between the Public Staff and DNCP rather than acceptance of a particular analytical model. He also testified that the agreements on ROE and capital structure discussed above could only occur in the context of various compromises by both parties on other issues. Finally, he testified that he believes a 9.90% ROE accounts for the impact on customers when viewed in the context of the overall settlement. He stated that, first, the settlement as a whole is reasonable with regard to the ultimate impact on customers, which is the impact on their monthly bills. Second, he noted that the impact of changing economic conditions in the DNCP service territory is difficult to adequately quantify, as there exist both economic improvement and economic problems. Third, he noted that the one-time payment of $400,000 to assist DNCP's low-income customers in North Carolina, which will come from earnings that would otherwise go to shareholders, will help mitigate the rate increase for the customers who have the greatest need and feel the impact of economic conditions most severely. Witness Hinton concluded that because the contribution could not lawfully be ordered by the Commission in the absence of Company agreement, it therefore provides a response to the impact of economic conditions on customers that could only exist with a settlement agreement, which adds to the reasonableness of the agreed-upon ROE.

At the hearing, witness Hevert testified in response to questions from counsel for CUCA and the Attorney General with regard to the 13.45% Bloomberg estimated market return he used in his CAPM analysis, which as he explained in his rebuttal testimony reflects return expected by analysts covering the companies that compose the S&P 500 Index. It does not represent the return for utilities, but is the expected market return from which the risk-free rate of return is subtracted to find the Market Risk Premium. The Market Risk Premium is then multiplied by the Beta coefficient, which represents a given utility's risk relative to the market. At the hearing, witness Hevert stated that 13.45% is well within that range considering an average historical market return of 12%, and the historical variation in returns of about 20%. In response to questioning from CUCA counsel as to whether his recommended ROE would be higher or lower if he had used the same approaches to his methodologies in this case as in previous cases, witness Hevert explained that it makes sense to apply different weights to the approaches as the markets change, because one model's assumptions no longer become as relevant to the market circumstances as they had been.

In response to questioning by the Attorney General, witness Hevert testified to the recent volatility in the utility sector, as exemplified by the variance in stock prices used as an input to his constant growth DCF analysis. In response to questions from counsel for Nucor, witness Hevert testified that looking at annual averages of returns may indicate a distorted view of trends in returns, since there may be years with fewer cases, or years with cases from jurisdictions that tend to authorize lower returns, rather than looking at individual cases.

On redirect questioning, witness Hevert reiterated that state regulatory commissions generally do not base rate of return decisions on evidence provided by a single witness, and that often state commissions like the Commission have authorized returns lower than his recommendation and higher than intervenor recommendations. He confirmed that the stipulated ROE of 9.90% is slightly below the lower end of his recommended range, and slightly above the higher end of Public Staff witness Hinton's recommended range. He stated the only instance he can recall of a commission authorizing an ROE comparable to the 9.0% and 8.6% ROEs recommended by Nucor and CUCA was in Hawaii, and that that case involved a reduction to the authorized ROE to account for system inefficiencies.

Public Witness Testimony

The public witness testimony heard by the Commission is summarized below.

Belinda Joyner of Garysburg in Northampton County, testifying on behalf of Concerned Citizens of Northampton County, stated that elderly customers on fixed income and retired State employees have to make purchasing decisions based on their limited income whether to buy groceries, medicine, and other items. She testified that without power these customers cannot cook, wash, nor otherwise function, and that a 17% increase in rates is unfair.

Tony Burnette, President of the Northampton County NAACP, is a caregiver for her elderly mother. She testified that a 17% increase would be detrimental to elderly customers and that elderly customers are often at home all day, and would likely use more than the 1000 kilowatts (kW), the monthly usage of an average customer.

Larry Abram of Tillery in Halifax County agreed with other witnesses regarding the difficulty elderly customers would have paying their bills.

Dean Knight of Halifax testified that his cotton gin business has electric bills of about $150,000 per month for three months of the year, and he must pay for improvements to his equipment within his budget, rather than by raising his rates.

Janice Bellamy of Whitakers in Edgecombe and Nash Counties testified to the difficulty she and others on fixed incomes have in paying their bills, such as water and electric bills.

Regina Moffett of Whitakers, advocating for seniors, stated that the proposed rate increase would impact the entire local community and that higher bills would result in decreased church contributions. She also testified that when she became a Dominion customer, she saw a “great decrease” in her electric bill.

Betty Bennett of Garysburg testified that a 17% increase in electricity rates was too high.

Peter Bishop, the Director of Economic Development for Currituck County, testified on behalf of the Currituck County Board of Commissioners. He testified with respect to DNCP witness Hevert’s testimony that while North Carolina “and this region” have improved significantly since the recession, the counties within DNCP’s service area have not fared well. He stated that the Company could have made a better argument with regard to economic conditions in the area and presented several statistics related to unemployment, poverty rate, median household income, net loss of population, and new businesses showing that the counties within DNCP’s service area are worse off than other counties in the State. Mr. Bishop also recommended that the Commission exercise caution when making determinations regarding recovery of coal ash costs, as this is a developing issue, and stated that the best approach may be to wait and see how coal ash cost recovery is handled in the federal courts before setting precedent for this State.

Robert Woodard, Chairman of the Dare County Board of Commissioners, testified in support of the Dare County Board of Commissioners’ resolution that was filed on July 19, 2016, in this proceeding. He also testified that the Board’s position is that any rate increase would place an undue hardship on Dare County’s citizens.

Walter Overman, Vice Chairman of the Dare County Board of Commissioners, testified that Dare County’s population has not seen a 17% or even a 6% increase in wages since DNCP’s last rate case. He testified that lower-wage residents would be hit especially hard in an area with a high cost of living. He asked that the rate increase be denied.

Dwight Wheless of Columbia in Tyrrell County testified in support of the Columbia Town Board of Aldermen’s resolution in opposition to the proposed rate increase. He testified that Tyrrell County has the second lowest per capita income in the State and its citizens would be most hurt by an increase in the cost of electricity. He also testified that Columbia has not experienced any recovery and that its residents are already challenged by constant increases in the cost of food and pharmaceuticals.

Robert Edwards of Nags Head in Dare County testified that the requested rate increase should not be granted. He testified that inflation has remained near zero in recent years and that if the Company made wise and prudent investments, those alone should have improved productivity and reduced costs so that customer rates should actually be lowered. He testified that DNCP should hedge fuel cost fluctuations with long-term purchase agreements and that customers should not be exposed to fuel cost increases. He testified that the proposed increase for residential customers as compared to large users is unfair, and that the requested rate of return on equity is too high.

Manny Madeiros of Kitty Hawk in Dare County testified that DNCP's retail electric rates should not reflect the cost of renewable energy production.

Judy Williams of Manteo in Dare County testified that she and others are living on fixed incomes and even a 7% increase in rates is too high.

Martha MacDonald of Williamston in Martin County testified that the rate increase would have a direct negative impact on seniors, most of whom have Social Security as their sole income, averaging $1300 a month. She testified that Martin County is a Tier 1 County, and that seniors are often forced to choose between paying their electric or water bills or buying food or medicine. She also testified that some residents cannot afford detached homes with insulation and are paying high bills for electricity in mobile homes. She testified that DNCP does a good job restoring power when there are outages.

John MacDonald of Williamston testified that he and many customers in the area are on fixed incomes and cannot afford the proposed rate increase.

Tawilda Bryant of Jamesville in Martin County testified in support of Ms. MacDonald's testimony on the impact of the proposed rate increase on seniors.

Rhett White, the Town Manager of Columbia in Tyrrell County, testified that the Town has struggled in the past to absorb electric rate increases and fuel charge adjustments without increasing local property taxes. He testified that Columbia could not withstand an increase of even 5.9% without an increase of 2 cents per $100 in the Town's tax rate. He testified that many of Columbia's elderly residents are on fixed incomes, sometimes living on the minimum Social Security check of $750 per month. He testified that a typical widowed resident living in a home valued at $75,000 would have to pay another $15 in annual taxes to cover the Town's increased power bills, in addition to the more than $84 that she will pay for her own residential power bill. He also testified that the increase to the County's own power bills would result in increased county taxes for that same resident. He stated that the proposed rate increase would negatively affect the Town's businesses and industry, and that the recent recession is not over in rural Columbia and Tyrrell County. He testified that wages are lower than elsewhere in northeastern North Carolina, unemployment is much higher than throughout the State, poverty rates are high, median household incomes remain the lowest in the region, and out-migration of young residents in search of jobs continues. He testified that the economic climate in Columbia is very different from that described by DNCP witness Hevert, and that the Town is made up mostly of low-income, working residents in a Tier 1 County.

Ronnie Smith, the Chair of the County Commissioners of Martin County, testified that many people in the area cannot afford the proposed increase, and that even small increases impact residents on fixed incomes.

John Liddick of Williamston testified that during the cold winter weather in the past, residents have said they could not afford their electric bills.

Linda Gibson of Williamston testified that most seniors are on fixed incomes of $600 or $700 per month, and that once they pay one or two bills, they have just enough left to buy food. She testified that most jobs in Martin County pay minimum wage or just a bit more and even young people have trouble making ends meet. She also testified in support of DNCP's good service in terms of restoring power after outages.

Samantha Komar of Williamston testified that she is a veteran and on a fixed income. She testified that the median income in the town is $15,000 per year and that residents already often have to choose between paying their electric and water bills or for food and medication.

Louise Simmons of Jamesville testified that she would not be able to pay any more on her electric bill.

Jerry McCrary, the Mayor of Parmele, Martin County, testified that Parmele has about 300 citizens, the majority of whom are seniors. He also testified that the proposed rate increase would harm these residents who already have to choose between buying food, medicine, and paying their bills.

Glenda Barnes of Parmele testified that the proposed 17% increase is too high.

Reginald William Ross, Jr. of Williamston testified that many of the local residents are seniors on fixed income making difficult choices about buying food or medicine.

Legal Standards Applicable to Rate of Return Findings by the Commission

The Commission's analysis of and decision on rate of return on rate base and allowed rate of return on common equity in this case is governed by the United States Supreme Court's Hope and Bluefield decisions,[10] the requirements of G.S. 62-133, and the North Carolina Supreme Court decisions interpreting and applying each of the foregoing to rate of return decisions by the Commission.

[10] Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944) (Hope); Bluefield Waterworks & Improvement Co. v. Public Service Commission, 262 U.S. 679 (1923) (Bluefield).

In Bluefield, the US Supreme Court established the basic framework for rate of return regulation of public utilities. On this subject, the Court held that:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; . . . [t]he return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.

Bluefield, 262 U.S. at 692-93. In the subsequent Hope decision, the Court expanded on its analysis by stating:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock…. By that standard the return to the equity owner should be commensurate with the returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

Hope, 320 U.S. at 603.

The Commission has looked to the Hope and Bluefield standards as guidance for setting rates. In Docket No. E-7, Sub 1026, the Commission noted that:

> First, there are, as the Commission noted in the DEP Rate Order, constitutional constraints upon the Commission's return on equity decision, established by the United States Supreme Court decisions in *Bluefield Waterworks & Improvement Co., v. Pub. Serv. Comm'n of W. Va*., 262 U.S. 679 (1923) (*Bluefield*), and *Fed. Power Comm'n v. Hope Natural Gas Co*., 320 U.S. 591 (1944) (*Hope*): To fix rates that do not allow a utility to recover its costs, including the cost of equity capital, would be an unconstitutional taking. In assessing the impact of changing economic conditions on customers in setting an ROE, the Commission must still provide the public utility with the opportunity, by sound management, to (1) produce a fair profit for its shareholders, in view of current economic conditions, (2) maintain its facilities and service, and (3) compete in the marketplace for capital. State ex rel. Utilities Commission v. General Telephone Co. of the Southeast, 281 N.C. 318, 370, 189 S.E.2d 705, 757 (1972). As the Supreme Court held in that case, these factors constitute "the test of a fair rate of return declared" in Bluefield and Hope.

Id., at 7.

The Commission must balance the interests of investors and customers in setting the rate of return on equity. As the Commission has stated, "the Commission is and must always be mindful of the North Carolina Supreme Court's command that the Commission's task is to set rates as low as possible consistent with the dictates of the United States and North Carolina Constitutions."[11] In that regard, the return should be neither excessive nor confiscatory; it should be the minimum amount needed to meet the Hope and Bluefield comparable risk, capital attraction, and financial integrity standards.

In addition, the Supreme Court has held that "although the Commission must make findings of fact with respect to the impact of changing economic conditions upon consumers," it is not required to "'quantify' the influence of this factor upon the final ROE determination."[12] The Commission echoed this distinction in the 2015 Remand Order as well, stating that it is "not required to isolate and quantify the effect of changing economic conditions on consumers in order to determine the appropriate rate of return on equity."[13]

The Supreme Court has also, however, made clear that the Commission "must make findings of fact regarding the impact of changing economic conditions on customers when determining the proper ROE for a public utility."[14] In Cooper II, which addressed an appeal of the Commission's order on DNCP's previous base rate application, the Supreme Court directed the Commission on remand to "make additional findings of fact concerning the impact of changing economic conditions on customers."[15] The Commission made such additional findings of fact in its Order on Remand.[16]

Finally, when a settlement agreement has not been adopted by all of the parties to a case, its acceptance by the Commission is governed by the standards set out by the

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[11] Docket No. E-7, Sub 1026, Order Granting General Rate Increase, (Sept. 24, 2013) at 24; see also Docket No. G-9, Sub 631, Order Approving Partial Rate Increase and Allowing Integrity Management Rider, (Dec. 17, 2013), at 26 (noting North Carolina Supreme Court's determination that the provisions of G.S. 62-133 "effectively require the Commission to fix rates as low as may be reasonably consistent with the requirements of the Due Process Clause of the Fourteenth Amendment to the Constitution of the United States, those of the State Constitution, Art. I, § 19, being the same in this respect"); 2015 Remand Order at 40 ("the Commission in every case seeks to comply with the North Carolina Supreme Court's mandate that the Commission establish rates as low as possible within Constitutional limits.").

[12] State ex rel. Utilities Comm'n v. Cooper, 367 N.C. 644, 766 S.E.2d 827 (2014). In this case the court affirmed the Commission's Order on Remand, issued October 23, 2013, in Docket No. E-7, Sub 989, at pages 34-35, where the Commission pointed out that "adjusting investors' required costs based on factors upon which investors do not base their willingness to invest is an unsupportable theory or concept. The proper way to take into account customer ability to pay is in the Commission's exercise of fixing rates as low as reasonably possible without violating constitutional proscriptions against confiscation of property. This is in accord with the 'end result' test of Hope. This the Commission has done." See also State ex rel. Utils. Comm'n v. Cooper, 367 N.C. 741, 745-46, 767 S.E.2d 305, 308 (2015).

[13] DNCP Remand Order at 26.

[14] State ex rel. Utils. Comm'n v. Cooper, 367 N.C. 430, 758 S.E.2d 635, 642 (2014) (Cooper II), See also State ex rel. Utils. Comm'n v. Cooper, 366 N.C. 484, 739 S.E.2d 541 (2013) (Cooper I).

[15] Cooper II, 758 S.E.2d at 643.

[16] DNCP Remand Order at 4-10.

North Carolina Supreme Court in State ex rel. Utilities Commission v. Carolina Utility Customers Association, Inc., 348 N.C. 452, 500 S.E.2d 693 (1998) (CUCA I), and State ex rel. Utilities Commission v. Carolina Utility Customers Association, Inc., 351 N.C. 223, 524 S.E.2d 10 (2000) (CUCA II). In CUCA I*,* the Supreme Court held that

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

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

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

With these legal principles in mind, the Commission now turns to the analysis of the evidence in this proceeding relating to a determination of the appropriate overall rate of return on rate base and allowed return on common equity for use in this proceeding.

Analysis of the Evidence

In order to reach an appropriate independent conclusion regarding return on equity, the Commission should evaluate the available evidence, particularly that presented by conflicting expert witnesses. Cooper I, 366 N.C. at 492-493; CUCA I*,* 348 N.C. at 460-467*;* CUCA II*,* 351 N.C. at 229-230.

In addition to its evaluation of the expert evidence, the Commission must also make findings of fact regarding the impact of changing economic conditions on customers when determining the approved rate of return on equity for a public utility. Cooper, 366 N.C. at 491, 739 S.E.2d at 548. There is no specific and discrete numerical basis for quantifying the impact of economic conditions on customers. However, the impact on customers of changing economic conditions is embedded in the return on equity expert witnesses' analyses. The Commission noted this at page 38 of its 2012 Rate Order: "This impact is essentially inherent in the ranges presented by the return on equity expert witnesses, whose testimony plainly recognized economic conditions – through the use of econometric models – as a factor to be considered in setting rates of return."

The evidence in this proceeding related to the determination of an overall rate of return on rate base and allowed rate of return on common equity is provided in the testimony of the public witnesses, the testimony and exhibits of DNCP's witness Hevert (and, in support of witness Hevert's recommendations, in the testimony of DNCP witnesses Curtis and Chapman), and the testimony and exhibits of Public Staff witness Hinton, Nucor witness Woolridge, and CUCA witness O'Donnell, and the Stipulation.

Witness Hevert used four different analytical methods, each with multiple variations, to estimate the cost of equity capital for DNCP. He ran a constant growth DCF method with 30-day, 90-day and 180-day low, mean, and high averages for each of his proxy companies, which as updated in his rebuttal testimony resulted in a rate of return on equity range of 8.14% to 9.32%. The range for his updated multi-stage DCF analysis is 8.85% to 9.97%. The range for his updated CAPM analysis is 8.87% to 11.22%, and the range for his updated bond yield plus risk premium analysis is 10.02% to 10.38%. The range between the highest number produced by the four methodologies, 11.22%, and the lowest number, 8.14%, encompasses the stipulated rate of return on equity of 9.90%. Further, the average of witness Hevert's updated analytical results, using the DCF mean growth rate results, is 9.45% (where the CAPM is based on the Bloomberg market risk premium) to 9.58% (where the CAPM is based on the Value Line market risk premium). However, witness Hevert testified that the constant growth DCF results "are difficult to reconcile with observable, prevailing market conditions," and likely reflect increases in utility stock prices that are a temporary overvaluation.

The Commission gives significant weight to witness Hevert's testimony that constant growth DCF results should be viewed with caution in current market conditions. While current stock prices are an observable fact, whether overvalued or not, an underlying assumption of the constant growth DCF is that the price to earnings ratio (P/E) remains constant. However, as noted by witness Hervert, utility sector P/E ratios have increased to the point that they have exceeded both their long-term average and the market P/E. In addition, constant growth DCF results are below authorized returns.

As a result, the Commission finds it reasonable in the current economic circumstances to give no weight to the constant growth DCF results, and to give substantial weight to an averaging of the high growth rate multi-stage DCF, the Value Line-based market risk premium CAPM, and the bond yield plus risk premium results, which indicates a 9.86% ROE. The result of this averaging, being only four basis points below the stipulated 9.90% ROE, is strongly supportive of the stipulated ROE, particularly in light of the Supreme Court's decision in <u>State ex rel. Utils. Comm'n v. General Telephone Co</u>., 285 N.C. 671, 681, 208 S.E.2d 681, 670 (1974) (a "zone of reasonableness extending over a few hundredths of one percent" exists within which the Commission may appropriately exercise its discretion in choosing a proper rate of return on equity).

In addition, the Commission gives substantial weight to witness Hevert's stipulation testimony in support of the stipulated 9.90% ROE. He testified that although the stipulated ROE is somewhat below the lower bound of his recommended range (i.e., 10.25%), he recognized that the Stipulation represents the give-and-take among the Stipulating Parties regarding multiple issues that would otherwise be contested by the Stipulating Parties. In addition, he relied on DNCP's determination that the terms of the Stipulation, taken as a whole, are such that DNCP will be able to raise the capital required to continue the investments required to provide safe and reliable service, and that it will be able to do so when needed and at a reasonable cost rates. The Commission notes that the approved ROE is just one of many factors that affect the earnings available to pay a return to equity investors, and therefore it is essential to assess the reasonableness of the ROE in the context of all the issues that affect earnings.

The Commission agrees with witness Hevert's testimony that although the stipulated ROE falls within the range of analytical results presented in his direct and rebuttal testimony, current capital market conditions are such that the models used to estimate the cost of equity continue to produce a wide range of sometimes conflicting estimates. Indeed, all the cost of capital witnesses used multiple analytical models, with wide-ranging results.

The Commission also gives substantial weight to witness Hevert's testimony that it is important to keep in mind that the models used to estimate the cost of equity reflect capital markets and, therefore, general economic conditions. Given that changes in economic conditions in North Carolina are related to the domestic economy, it is reasonable to conclude that both are reflected in the analytical estimates of the ROE. The Commission further finds credible witness Hevert's testimony that, on balance, economic data regarding North Carolina and the United States do not alter the cost of equity estimates one way or the other.

The Commission additionally gives substantial weight to the stipulation testimony of Company witness Curtis that the concessions the Company has made through the Stipulation reasonably balance its customers' interest in receiving the lowest rate impact while also meeting DNCP's need to recover the substantial investments that it has made in order to continue to comply with regulatory requirements and safely provide high quality electric service.

Based on the testimony of DNCP witnesses Hevert and Curtis, the 9.90% stipulated ROE, in the context of the settlement as a whole, will be sufficient to meet the requirements of investors in capital markets. The corresponding question is whether a 9.90% ROE imposes no more burden on DNCP customers than is necessary for the Company to provide reliable electric service. In this regard, the Commission gives substantial weight to Public Staff witness Hinton's settlement testimony that the stipulated

9.90% ROE represents a reasonable middle ground between the Public Staff and DNCP, higher than his recommended range of 8.80% to 9.80%, and lower than the Company's recommended range of 10.25% to 10.75%.

The Commission also gives weight to witness Hinton's direct and settlement testimony in its focus on the impact on customers from multiple perspectives. In particular, he testified regarding: (1) data showing improvement in economic conditions, notably unemployment and per capita income, for the population within DNCP's service territory; (2) the benefit customers will receive from lower rates as a result of a negotiated settlement that will reduce the Company's proposed rate increase by over $12 million – a result that eliminates uncertainty regarding the chance that a higher rate increase could have been approved in a fully-contested proceeding; and (3) the $400,000 to be paid by shareholders to assist low-income customers who are the most impacted by a rate increase.

Witness Hinton's direct (pre-settlement) testimony employed three primary analytical methods: a constant growth DCF, a regression analysis of allowed ROEs, and the comparable earnings method. The Commission finds the high end of his comparable earnings results to be probative and compelling in the circumstances of this case. As witness Hinton noted, the comparable earnings method is well-suited to the Hope legal standard of authorizing a utility ROE that allows investors to earn a return comparable to returns available on alternative investments with similar risk. As a result, the Commission gives substantial weight to the high end of the range of results from witness Hinton's updated comparable earnings analysis, where the three highest ROE results – 10.0%, 9.9% and 9.7% - average 9.867%. The Commission considers such substantial weight appropriate in the present circumstances where there is a wide range of analytical results, all with strengths and weaknesses. Thus, it is reasonable to rely more heavily on results that support a middle ground among the analyses of the competing witnesses.

Nucor witness Woolridge acknowledged that his recommendation of an ROE of 8.60% out of a range of 7.90% to 8.75% is below the average authorized ROEs for electric utility companies. The Commission notes witness Hevert's rebuttal testimony that the lowest authorized ROE for a vertically integrated electric utility since January 2014 was 70 basis points above witness Woolridge's 8.60% recommendation. The Commission cannot blindly follow ROE results allowed by other commissions, but must determine the appropriate ROE based upon the evidence and particular circumstances of each case. However, the Commission believes that the ROE trends and decisions by other regulatory authorities deserve some weight, as they provide a check or additional perspective on the case-specific circumstances. In addition, DNCP must compete with utilities in other jurisdictions for capital from investors. In this regard, the Commission finds persuasive witness Hevert's testimony at the hearing that North Carolina is generally viewed by the credit ratings agencies to be a supportive jurisdiction, and that an ROE of 9.90% is consistent with the returns recently awarded to utilities in similarly constructive jurisdictions. The Commission has not relied on this evidence to arrive at its ROE decision. Instead, the Commission has considered it as a check or as corroboration with regard to other evidence on ROE in this proceeding. That check allows the Commission to ensure that its ROE decision is not vastly out of line with rates of return authorized for regulated utilities in other jurisdictions. In addition, the Commission finds persuasive witness Hevert's responses to witness Woolridge and counsel for Nucor regarding the use of annual averages of the inputs to the DCF analysis and other inputs to his analyses. The Commission gives weight to witness Hevert's rebuttals to witness Woolridge's testimony as discussed above and the check on witness Woolridge's recommended ROE provided by the comparison to other similar jurisdictions. The Commission concludes that witness Woolridge's result of 8.6% ROE is outside the bounds of reasonableness – there is no credible evidence showing that the cost of equity for DNCP has decreased by 160 basis points since the Company's last rate case - and would put the Company at a significant disadvantage in competitive capital markets when attempting to raise capital needed to fund its operations.

The Commission gives little weight to witness O'Donnell's ROE testimony. The Commission find persuasive witness Hevert's responses to witness O'Donnell's' arguments regarding the long-term growth rate and other inputs to his analyses, particularly witness Hevert's discussion regarding the distinction between ROE and pension returns. The Commission agrees with witness Hevert that in light of the <u>Hope</u> case ruling that it is the end result that is the primary consideration in ROE determinations. In this case, witness O'Donnell's end result of a 9.0% ROE, at 120 basis points lower than the last authorized ROE for DNCP, overstates the decline in investors' required return, and therefore is outside the bounds of reasonableness and would put the Company at a significant disadvantage in raising capital needed to fund its operations. Witness O'Donnell provided no testimony as to the reasonableness of the multi-stage DCF model or its application in this proceeding other than with respect to the long-term growth rate.

Counsel for Nucor, CUCA and the Attorney General questioned witness Hevert about various aspects of his analyses; however, their cross-examination did not establish a persuasive basis for an ROE lower than 9.90%. The stipulated 9.90% ROE is itself 60 basis points lower than the 10.5% ROE recommendation resulting from witness Hevert's analysis. The stipulated 9.90% ROE is further corroborated by witness Hevert's hearing testimony that in only one case that he can recall has a commission authorized an ROE comparable to the 9.0% and 8.6% ROEs recommended by Nucor and CUCA, and but for a decrement applied in that case for unrelated reasons, the ROE in that instance would have been 9.5%. Again, while the Commission has not relied on this evidence to arrive at its ROE decision, it has considered it as a check or as corroboration with regard to other evidence on ROE in this proceeding that allows the Commission to ensure that its ROE decision is not vastly out of line with rates of return authorized for regulated utilities in other jurisdictions. Overall, the Commission finds the settlement testimony of witness Hevert and witness Hinton to be credible, substantial, and probative evidence that supports approval of a 9.90% rate of return on common equity for DNCP in this proceeding.

As discussed above, numerous customers provided testimony at the public hearings as to the impact that any rate increase would have, especially on those customers in DNCP's service area who are on fixed incomes. The Commission acknowledges and accepts as true the proposition that some percentage of DNCP's customers, particularly those living on fixed incomes, are economically vulnerable and may struggle to pay an increase in DNCP's rates granted in this docket. The Commission gives substantial weight to the public witness testimony as it undertakes to balance the interests of DNCP's customers with the Company's need to obtain financing on reasonable terms for the continuation of reliable electric service.

Conclusions on Return

The Commission has the obligation to reach its own independent conclusion as to whether the Stipulation is just and reasonable, fair to customers, the Company and its shareholders in light of changing economic conditions, and otherwise sufficient to satisfy the requirements of G.S. 62-133. In sum, the Commission finds and concludes for purposes of this case and after thoroughly and independently reviewing all of the evidence that an authorized ROE of 9.90% is just and reasonable based on all of the evidence presented.

The Commission understands that rate increases are not favored by ratepayers and that some portion of any utility's customer base will find it difficult to pay their utility bills from time to time. The Commission further acknowledges that it is the Commission's primary responsibility to protect the interests of utility customers in setting rates for public utilities by complying with the legal principles discussed earlier in this Order. It is also the Commission's responsibility to abide by the constitutional requirements of the Hope and Bluefield cases as reflected in the provisions of G.S. 62-133 and to balance the interests of customers and the regulated utilities.

The Commission finds and concludes, for the reasons set forth herein, that the ROE recommendations of witnesses Woolridge and O'Donnell are to be afforded little weight. The Commission concludes that their analyses would produce a significant risk that the Company could not obtain equity financing on reasonable terms. The Commission further concludes that a 9.90% ROE is reasonable based in part on probative, credible evidence from witness Hevert and witness Hinton. In particular, rather than accept any one approach of any single witness, the Commission has independently determined that the combination of witness Hevert's updated analytical results, as well as witness Hinton's updated comparable earnings results, are supportive of an ROE of 9.90%. The 9.90% ROE is also supported by the Stipulation and the accompanying testimony of DNCP and Public Staff witnesses as to its reasonableness. Finally, as discussed below in more detail, the Commission concludes that a 9.90% ROE is reasonable and appropriate in light of the numerous other adjustments that affect earnings available to investors. Such adjustments include reductions in the Company's requested rate base, reductions in its requested operating expenses, an approved capital structure that imputes a lower equity ratio than the Company's actual capital structure, and a $400,000 shareholder contribution to assist low-income customers. Along with these adjustments, the impact of changing economic conditions on DNCP's customers has been taken into account in determining the approved ROE.

Consumers pay rates, a charge in cents per kilowatt-hour for the electric energy they consume. They do not pay a rate of return on equity. To the extent that the Commission makes downward adjustments to rate base, reduces the approved common equity component of capital structure, disallows test year expenses or increases pro forma test year revenues, the Commission reduces the rates consumers pay during the future period rates will be in effect. However, the utility's investors' compensation for the provision of service to consumers takes the form of return on investment. To the extent the Commission makes adjustments to reduce the overall cost of service, the Commission reduces the rates consumers otherwise must pay irrespective of its determination of rate of return on equity expressed as a percentage, in this case 9.90%. To the extent these adjustments reflect current economic conditions, and consumers' ability to pay, these adjustments reduce not only consumers' rates but also the return on equity, expressed in terms of dollars that investors actually earn. This is also in accord with the end result test of Hope.

In the present case, DNCP's initial Application requested a $51.073 million increase in DNCP's annual North Carolina revenues. That revenue increase would require an overall rate increase of 20.90%. In addition, DNCP requested a 10.5% rate of return on common equity, a 7.88% overall return on a rate base of $1.067 billion, and a capital structure that included 53.359% common equity. In the Company's supplemental and rebuttal cases, it revised its requested revenue increase to $46.8 million and its overall return to 7.805%. These are the "big picture" numbers in the case. However, the crucial details of DNCP's general rate Application, as in all general rate cases, are in the hundreds of line items in the NCUC Form E-1 that detail the Company's cost of service. The details of DNCP's Application, including the cost of service line items, are reviewed by the Public Staff and by other intervenors. The Public Staff typically recommends numerous adjustments to the utility's cost of service items, some adjustments increasing an item and some adjustments decreasing another item. These adjustments are presented by the Public Staff in its testimony, or, as in the present docket, in a settlement agreement with the utility.

In the present docket, the Public Staff's adjustments are shown in Settlement Exhibit II of the Stipulation. There are about 20 adjustments, some up and some down. However, the end result of all the adjustments is a reduction in DNCP's revenue requirement from the $46.752 million requested in the Company's rebuttal case to the stipulated amount of $34.732 million. Thus, the numerous adjustments made by the Public Staff, and approved herein by the Commission, reduce the total annual base revenues to be received by DNCP from ratepayers by $12.020 million, including a reduction of approximately $5.235 million resulting from a decrease in the rate of return to be paid to equity investors.[17] Although the ROE downward adjustment produces a direct reduction in the authorized rate of return on investment financed by equity investors, the numerous other downward adjustments reflected on Settlement Exhibit II further reduce the dollars the investors actually have the opportunity to receive. For example, the authorized 51.75% equity ratio in the capital structure, which is a regulatory

[17] See Settlement Exhibit II.

reduction from the Company's actual equity ratio of 53.92%, reduces revenues available for earnings by another $2.849 million. Thus, while the equity investor's cost was calculated under the terms of the Stipulation by applying a rate of return on equity of 9.90%, instead of the 10.5% requested in the Application, this is only one of many approved adjustments that reduces ratepayer responsibility and equity investor reward.

This is not to say that the Commission accepts the stipulated 9.90% rate of return on equity merely because it is lower than the 10.5% requested by DNCP. Indeed, the Commission has weighed the evidence of the expert ROE witnesses, and in finding some of that evidence to be highly probative and other parts of that evidence as entitled to little weight, has independently found support in the analytical results for a 9.90% ROE. In addition, the Commission concludes that each of the approximately 20 adjustments made by the Public Staff, and accepted herein by the Commission, reflects the fact that ratemaking, and the impact of rates on consumers, must be viewed as an integrated process where the ratemaking end result is what directly affects customers. The Commission's acceptance of the foregoing ratemaking adjustments, including the 9.90% rate of return on equity, reflects the Commission's application of its subjective, expert judgment under the Public Utilities Act that the end result is in compliance with the Commission's responsibility to establish rates as low as reasonably possible without transgressing constitutional constraints.

Solely focusing on the authorized rate of return on equity in assessing the impact of the Commission's decision on consumers' ability to pay in the current economic environment would fail to give a true and accurate picture of the issues presented to the Commission for decision and the totality of the Commission's order. Such an analysis would also be inconsistent with Hope and the CUCA cases. For example, when the Commission approves a reduction in the investment (rate base) against which the authorized 9.90% rate of return on equity is multiplied to produce the dollars in return on equity investment, the financial impact is a reduction in the rates paid by ratepayers and a reduction in the amount received by equity investors, the same result as if the Commission had instead reduced the 9.90% rate of return on equity. In the present case, the Stipulation included a reduction of $4.903 million in authorized rate base, and therefore, a substantial reduction in revenues available to pay earnings to shareholders, compared to the Company's position in its rebuttal testimony.[18]

As previously noted from the Hope decision, it is the "end result" of the Commission's order that must be examined in determining whether the order produces just and reasonable rates. Consistent with that requirement, the Commission has incorporated into its analysis all of the myriad factors that make up DNCP's revenue requirement, including the rate of return on equity and the impact of the Commission's decision regarding the consumers' ability to pay in the current economic environment. With respect to customers' ability to pay, an important adjunct to the 9.90% ROE is the $400,000 shareholder contribution to assist low-income customers, notwithstanding the

[18] See Fernald Exhibit 1, Schedule 2, Revised (filed with the settlement testimony of Public Staff witness Fernald).

significant improvement in economic conditions in DNCP's service territory since the Company's last rate case. Based on the impact on customers, the requirements of investors in capital markets, and the total effect of the Stipulation with its numerous reductions to the Company's proposed revenue requirement, the Commission concludes that a 9.90% rate of return on equity produces just and reasonable rates for DNCP and for its ratepayers. Any further reduction in the authorized rate of return on equity is not justified by any evidence that the Commission has found to be credible and probative in its fact finding role.

In separate post-hearing briefs, the AGO and Nucor emphasized the generally lower results produced by the Constant Growth DCF analyses of all the witnesses. They argue that either the implementation, or interpretation of results, by witnesses Hinton and Hevert in their Mutli-Growth DCF, Comparable Earning, Risk Premium, or CAPM analyses are flawed and excessive. The AGO, which presented no witness, recommends an ROE of less than 9.0%, and Nucor recommends an ROE of 8.6% consistent with the testimony of witness Woolridge.

In its post-hearing Brief, CUCA contends that the stipulated ROE of 9.90% is too high because it represents a "split the baby" approach between the ROE proposed by Public Staff witness Hinton and the ROE proposed by DNCP witness Hevert. Further, CUCA maintains that each of the analytical models used by witness Hevert is seriously flawed, as discussed by CUCA witness O'Donnell in his testimony.

After consideration of the entire record and for the reasons stated herein, the Commission is not persuaded by the AGO or Nucor that the 9.9% ROE in the Stipulation is excessive. The Commission points out that each of the witnesses to this proceeding use considerable judgement or discretion in deciding which ROE estimation method or model to use and present into evidence, or even withhold. In addition, each ROE witness used discretion in deciding what inputs to use within each method, the interpretation of the results of each method, and how the results of each method were weighted in determining the ROE to recommend on behalf of their employer or client. The Commission is uniquely situated and legally charged with using its impartial judgement to determine the ROE using applicable legal standards. The Commission has used its impartial judgment as necessary and appropriate to evaluate and weigh the evidence in reaching its conclusions and findings relevant to the ROE issue as set forth in this Order.

After a careful review of all the evidence in this case, and adhering to the requirements of the above cited legal precedents, the Commission finds that the overall rate of return on rate base and the allowed rate of return on common equity, as well as the resulting customer rates provided for under the Stipulation, are just and reasonable, fair to both DNCP and its customers, appropriate for use in this proceeding, and should be approved. The rate increase approved herein, as well as the rates of return underlying such rates, are just, reasonable and fair to customers considering the impact of changing economic conditions, and are required in order to allow DNCP, by sound management, to produce a fair return for its shareholders, maintain its facilities and provide services in accordance with the reasonable requirements of its customers in the territory covered by its franchise, and to compete in the market for capital funds on terms that are reasonable and that are fair to its customers and existing investors.

The Commission notes further that its approval of an ROE at the level of 9.90% - or for that matter, at any level - is not a guarantee to the Company that it will earn a return on its common equity at that level. As noted above, on June 30, 2016, the Company's fully-adjusted earned rate of return on equity capital for the update period was only 5.50%, far below the Company's currently authorized 10.2%. Rather, as North Carolina law requires, setting the ROE at this level merely affords DNCP the opportunity to achieve such a return. See G.S. 62-133(b)(4). The Commission believes, based upon all the evidence presented, that the ROE provided for here will indeed afford the Company the opportunity to earn a reasonable and sufficient return for its shareholders while at the same time producing rates that are fair to its customers.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 35

The evidence supporting this finding of fact and these conclusions is contained in the Application and Form E-1 of DNCP, the testimony and exhibits of the witnesses, the Stipulation, and the entire record in this proceeding.

In the Application and direct testimony and exhibits, DNCP provided evidence supporting an increase of $51.073 million, or approximately 20.90%, in its annual non-fuel revenues from its North Carolina retail electric operations. On August 12, 2016, the Company filed supplemental direct testimony and exhibits updating several cost of service adjustments. These updated adjustments decreased the Company's revenue requirement by $3.3 million, for a revised increase in North Carolina retail revenue of $47.8 million, which was reduced again in the Company's rebuttal case filed on September 26, 2016 to $46.8 million.

On September 7, 2016, the Public Staff filed the direct testimony of witness Fernald, presenting her recommended accounting and ratemaking adjustments to the Company's proposed revenue requirement. Accounting for these adjustments, she recommended an increase in the Company's annual base non-fuel operating revenue of $19,755,000. Nucor filed testimony of witness Kollen, who also made recommendations for accounting adjustments.

On September 26, 2016, the Company filed the rebuttal testimony of witness Stevens, which responded to the various accounting adjustments and recommendations of witness Fernald and witness Kollen.

On October 3, 2016, the Company, the Public Staff and CIGFUR I entered into and filed the Stipulation. Pursuant to the Stipulation, the Company, the Public Staff and CIGFUR I agreed upon an increase to DNCP's annual non-fuel revenue from its North Carolina retail electric operations of $34.732 million or 14.25% and a decrease in annual base fuel revenues of $8.942 million.

Also on October 3, 2016, the Company filed the joint testimony of witness Stevens and witness McLeod in support of the stipulated revenue increase. These witnesses testified in support of the accounting and ratemaking adjustments agreed upon in the Stipulation. They also testified that the Stipulation is the result of negotiations between the Stipulating Parties who, collectively, represent both residential and industrial customer interests impacted by this case. Also on October 3, 2016, the Public Staff filed testimony of witness Fernald recommending and supporting the stipulated adjustments to the Company's requested revenue increase.

Based upon the evidence recited above and the cumulative testimony and evidence supporting the individual components of the stipulated revenue increase discussed throughout this Order, the Commission finds, in the exercise of its independent judgment, that the stipulated net revenue increase of $25.70 million for North Carolina retail electric operations in this case is just, reasonable, and appropriate for use in this proceeding.

The following schedules summarize the gross revenue and the rate of return that the Company should have a reasonable opportunity to achieve based on the determinations made herein. These schedules, illustrating the Company's gross revenue requirement, incorporate the findings and conclusions made by the Commission in this Order. As reflected in Schedule I, and as impacted by the other findings in this Order, DNCP is authorized to increase its annual level of gross revenues by $25.790 million, reflecting an increase of $34.732 million in base non-fuel revenues (including late payment fees and other revenues) and a decrease of $8.942 million in base fuel revenues.

SCHEDULE I
DOMINION NORTH CAROLINA POWER
North Carolina Retail Operations
Docket No. E-22, Sub 532
STATEMENT OF OPERATING INCOME
For the 12 Months Ended December 31, 2015
(000's Omitted)

Item	Present Rates	Approved Increase	Approved Rates
Electric sales revenues	$242,718	$34,310	$277,028
Base fuel revenues	99,755	(8,942)	90,813
Late payment fees	1,292	92	1,384
Other revenues	6,167	330	6,497
Total operating revenues	349,932	25,790	375,722
Fuel expenses	90,686	0	90,686
Other O&M expenses	98,829	160	98,989
Depr. and amort. expense	60,047	0	60,047
Gain / loss on disp. of property	309	0	309
Taxes other than income	15,233	0	15,233
Income taxes	23,891	9,929	33,820
Total operating expenses	288,995	10,089	299,084
Net operating income before adj.	60,937	15,701	76,638
Interest on customer deposits	(19)	0	(19)
Interest on tax deficiencies	(1)	0	(1)
Net operating income for return	$ 60,917	$15,701	$ 76,618

SCHEDULE II
DOMINION NORTH CAROLINA POWER
North Carolina Retail Operations
Docket No. E-22, Sub 532
STATEMENT OF RATE BASE AND RATE OF RETURN
For the 12 Months Ended December 31, 2015
(000's Omitted)

Item	Present Rates	Approved Increase	Approved Rates
Electric plant in service	$1,947,252	$ 0	$1,947,252
Accumulated depr. and amort.	(716,858)	0	(716,858)
Net electric plant in service	1,230,394	0	1,230,394
Materials and supplies	44,916	0	44,916
Cash working capital	16,406	2,070	18,476
Other additions	19,607	0	19,607
Other deductions	(17,434)	0	(17,434)
Customer deposits	(5,126)	0	(5,126)
Acc. deferred income taxes	(250,799)	0	(250,799)
Rounding	1	0	1
Total original cost rate base	$1,037,965	$ 2,070	$1,040,035
Rate of Return	5.87%		7.37%

SCHEDULE III
DOMINION NORTH CAROLINA POWER
North Carolina Retail Operations
Docket No. E-22, Sub 532
STATEMENT OF CAPITALIZATION AND RELATED COSTS
For the 12 Months Ended December 31, 2015
(000's Omitted)

Item	Capitalization Ratio	Original Cost Rate Base	Embedded Cost	Net Operating Income
		Present Rates – Original Cost Rate Base		
Long-Term Debt	48.25%	$ 500,818	4.650%	$23,288
Common equity	51.75%	537,147	7.010%	37,629
Total	100.00%	$1,037,965		$60,917
		Approved Rates – Original Cost Rate Base		
Long-Term Debt	48.25%	$ 501,817	4.650%	$23,334
Common equity	51.75%	538,218	9.900%	53,284
Total	100.00%	$1,040,035		$76,618

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 36

The evidence for this finding of fact and these conclusions is contained in the Stipulation, the testimony of DNCP witness Stevens and Public Staff witness Fernald, and the entire record in this proceeding.

Section XV of the Stipulation provides that the Company will make a one-time $400,000 shareholder contribution over and above its usual contribution to its North Carolina EnergyShare program, which provides energy assistance to customers in need in the Company's North Carolina service territory, by March 30, 2017. At the hearing, the Company notified the Commission that it would commit to making this contribution no later than early January, 2017, so that the funds would be available for the winter heating season. Company witness Stevens testified that the Company's usual annual EnergyShare expenditure in North Carolina was approximately $360,000, so the amount agreed upon in the Stipulation would effectively double the amount of shareholder contribution to low-income heating assistance.

The Commission notes that the $400,000 shareholder contribution to low-income energy assistance is a feature of the settlement between the Company, the Public Staff and CIGFUR I that could not have been ordered by the Commission without the agreement of the Company. The Commission finds and concludes that this provision of the Stipulation is just and reasonable to all parties in light of all the evidence presented.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 37-41

The evidence supporting these findings of fact and conclusions is found in the Company's verified Application and exhibits, the Stipulation, and the testimony of Company witnesses Pierce (as adopted by Haynes), and Haynes, Public Staff witness Floyd, Nucor witness Goins, and CUCA witness O'Donnell, and the entire record before the Commission in this proceeding.

Cost of Service Methodology – The Company's Application, as supported by witness Haynes, used the SWPA cost of service methodology to allocate production and transmission plant costs for both the North Carolina jurisdiction and the North Carolina retail customer classes. The SWPA method recognizes two components of providing service to customers - peak demand and average demand - when determining the responsibility for costs of production and transmission plant and related expenses. The peak demand component takes into account the hour when the load on the system is highest during both the summer months and the winter months. The average demand component recognizes that there is a load incurred by the system over the course of all hours during the year. The average demand is determined based upon the total energy provided to the customers during the year divided by the total number of hours in the year. The average component is then weighted by the system load factor, and the peak component is weighted by one minus the system load factor. The load factor is calculated by taking the Company's actually experienced average demand divided by its actually experienced peak demand during the test year.

Witness Haynes explained that DNCP developed and presented in its Form E-1, Item 45, the "per books," annualized, and "fully-adjusted" jurisdictional and customer class cost of service studies (COSS) based on the SWPA allocation method for the 12-months test year ended December 31, 2015. [19] In developing the SWPA COSS, the Company also made an adjustment to the Company's recorded summer and winter peaks to recognize and add back the kW generated by non-utility generators (NUGs) interconnected to DNCP's distribution system that are not included in those values. This NUG adjustment addresses a "mismatch" between the peak and the average components of the SWPA, as the kWh generated by distribution-interconnected NUGs were included in the average demand component of the SWPA but not in the summer and winter peak component. The NUG adjustment was calculated by determining the actual kW generated by distribution-interconnected NUGs at the time of the summer and winter peaks in both DNCP's Virginia and North Carolina service territories, and then adding these "state" values to each jurisdiction's respective recorded summer and winter peaks to arrive at the adjusted level. DNCP's fully adjusted SWPA COSS produced a North Carolina jurisdictional allocation factor of 5.1166%.

Company witness Haynes testified that the objective of jurisdictional and customer class cost of service studies is to determine the allocation of a share of the system's revenues, expenses, and plant related to providing service across multiple jurisdictions. Certain items can be assigned directly to the jurisdiction and classes based on the utility's records, but other items are not directly assignable and must be allocated. Witness Haynes stated that in this proceeding, the Company allocated its production and transmission plant and expenses using the SWPA cost of service methodology. He noted that the Commission has approved DNCP's use of the SWPA method in five other general rate case proceedings for the Company, dating back to 1983, including the 2012 Rate Case.

Company witness Haynes testified that the SWPA allocation method is consistent with the manner in which DNCP plans and operates its system. Specifically, the "Summer and Winter" peak component recognizes the total level of generation resources necessary to serve the system peaks while the average component recognizes the type of generation serving customers' energy needs year-round.

Company witness Haynes also emphasized that use of a single peak or other peak-only methodology could allow certain customer classes that have zero demand during the peak hour(s) of the year to fully avoid responsibility for production plant costs. Witness Haynes explained that a common example is that streetlights normally do not operate during peak hours. Company witness Haynes also highlighted the NS Class as another example unique to DNCP's North Carolina jurisdictional load. Witness Haynes explained that Nucor, the only customer in the NS Class, has an average annual demand

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[19] At the request of CIGFUR I and Nucor in discovery, and in response to the Commission's March 17, 2016 Order Denying Motion and Granting Alternative Relief, DNCP also developed and filed with the Commission a per books single coincident peak (1CP) COSS on May 31, 2016. The DNCP 1CP COSS is designed using only the single highest system peak during the test year, and produced a per books North Carolina jurisdictional allocation factor of 5.2354%.

throughout the year of approximately 100 megawatts (MW), while Nucor's average of its summer (June 2015) and winter (February 2015) coincident peak demands is approximately 42 MW. Witness Haynes explained that without recognizing an average component in the cost allocation, this customer class would "pay" for only 42 MW and escape cost responsibility for an average of 58 MW for the rest of the year (i.e., the average demand of 100 MW less the allocated demand of 42 MW). Witness Haynes explained that by recognizing both the energy needed to serve load at the peak hour, as well as energy consumed throughout the year, the SWPA method allocates some portion of these system costs to all customers, including those customers that can reduce their peak demand and those that may not place a demand on the system during the respective summer and winter peak hour. Such customers still use and receive the benefit of the Company's investments in production assets by paying lower energy costs, specifically fuel costs, during all other hours.

Public Staff witness Floyd agreed with the Company's use of the SWPA cost of service methodology in this proceeding because it appropriately allocates the Company's production plant costs in a way that most accurately reflects the Company's generation planning and operation. He testified that unlike other methodologies that allocate all of the production plant costs based on a single coincident peak or on a series of monthly peaks, the SWPA methodology recognizes that a portion of plant costs, particularly for base load generation, is incurred to meet annual energy requirements throughout the year and not solely to meet peak demand at a particular time. Witness Floyd also addressed the NUG adjustment to SWPA, stating that the Public Staff agrees with DNCP's adjustment as appropriately recognizing the impact that distribution connected NUGs have on DNCP's system.

Nucor witness Goins recommended that the Commission reject DNCP's use of the SWPA method and, instead, order DNCP to use the Summer-Winter Coincident Peak (S/W CP) method. Witness Goins developed and filed a fully adjusted S/W CP COSS that incorporated the cost-of-capital and ratemaking adjustments proposed by Nucor witnesses Woolridge and Kollen, respectively.

Witness Goins suggested that the use of the SWPA method is unreasonable because the SWPA methodology is used in almost none of the regulatory jurisdictions with which he was familiar. He further argued that the SWPA method is flawed for a number of reasons and ultimately allocates a greater portion of DNCP's cost of service to Nucor and other high load factor customers. Specifically, witness Goins argued that Nucor's load is totally interruptible and, therefore, should be excluded when deriving the SWPA allocation factors. Witness Goins contended that in failing to properly recognize Nucor's interruptible load, the Company overstated the cost to serve Schedule NS and understated the rate of return for Schedule NS. Finally, witness Goins argued that the use of SWPA harms Nucor and other high load factor customers who would be assigned lower levels of fixed production costs under a peak-only methodology.

Nucor witness Goins testified that should the Commission continue to find the SWPA method appropriate for use in this proceeding, the Commission should reject the system load factor weighting methodology used by DNCP and, instead, use a weighting that allocates a greater percentage of production costs based using peak demand and a lesser percentage based upon the average energy-based demand component. Specifically, witness Goins suggested that DNCP's system load factor weighting is heavily biased towards energy and suggested that the Commission could mitigate the bias by establishing weighting for the peak demand component at 75% or greater and the average demand component at 25% or less.

CUCA witness O'Donnell's arguments in support of the 1CP methodology were similar to those of witness Goins in support of S/W CP. Witness O'Donnell suggested that 1 CP best depicts how DNCP dispatches its plant to meet peak load. He further argued that he opposed SWPA because it sends the message to industrial consumers to use less energy and for residential and small consumers to use more energy, which will hurt manufacturing and economic development in Eastern North Carolina and, in time, raise rates to the residential and small commercial consumers when industrial consumers that cannot afford the higher rates move their operations elsewhere or simply close altogether.

In rebuttal, Company witness Haynes extensively addressed and rebutted the cost of service arguments of witness Goins on behalf of Nucor and witness O'Donnell on behalf of CUCA. Witness Haynes explained that the SWPA method reasonably and appropriately recognizes the two components of providing service to customers, peak demand, and average demand, and is consistent with the manner in which the Company's planning department plans for and meets DNCP's system needs, taking into consideration the need to meet both peak demands and the need to provide resources that can be operated to serve customers throughout the year. The "Summer and Winter" peak component recognizes the total level of generation resources necessary to serve the system peaks, while the average component recognizes the dispatch of different types of generation providing the system with low cost energy year-round. Witness Haynes pointed to the Company's recent additions of the intermediate/baseload gas-fired combined cycle 1,342 MW Warren County CC and the 1,358 MW Brunswick County CC (as well as the Company's historical investments in its baseload nuclear fleet) as production-related plant operated throughout the year to provide baseload energy to the Company's customers.

Witness Haynes responded to Nucor witness Goins' suggestion that SWPA is a rarely used methodology by explaining that there are numerous other jurisdictions, including the Company's Virginia jurisdiction, that include an "average" (energy) component in the development of production allocation factors. The Company operating in Virginia as Dominion Virginia Power has used the Average & Excess (A&E) cost allocation method in every Virginia rate proceeding dating back to 1972. Witness Haynes also testified that the SWPA and A&E methods have the benefit of also being relatively consistent (both include energy components) and, further, that preserving historical continuity in the method used to allocate costs will also avoid significant shifts in allocated costs to a given class between one rate case and the next.

In addressing the peak-only S/W CP and 1CP methods advocated by witnesses Goins and O'Donnell, witness Haynes explained that these methodologies are unreasonable and inappropriate for DNCP because their reliance on the single coincident peak hour or only the two hours of DNCP's summer and winter peaks is inconsistent with the way DNCP plans and operates its system to both meet the system peaks as well as to deliver low cost energy throughout the year. In addition to the new Warren County and Brunswick County Power Station investments, described above, witness Haynes also specifically pointed to the remaining $4.7 billion of nuclear plant in service at the end of 2015, which still represents approximately 30% of DNCP's total production plant investment. Witness Haynes also presented concerns that use of S/W CP would produce unreasonable results in other areas of DNCP's COSS, such as production plant O&M expenses.

Witness Haynes also presented a number of analyses showing that moving from a SWPA methodology to the S/W CP methodology would cause a significant shift of DNCP's cost of service between the classes and would shift recovery of production costs away from Nucor and other high load factor customers and to the residential class. For example, witness Haynes' analysis in his Rebuttal Table 4 showed that the NS Class rate of return increased from approximately 2% under the SWPA method to approximately 18% under Witness Goins' S/W CP method. Witness Haynes' Rebuttal Table 5 presented the shift in class rate of return indices (RORI) between SWPA and S/W CP, with the Schedule NS Class increasing from 0.40 under SWPA to 2.79 under the S/W CP method (an increase of over 597.5 %), while the residential class fell from a RORI 0.97 under the SWPA method to 0.65 under witness Goins' S/W CP method. Witness Haynes also noted that under the fully adjusted cost of service presented by witness Goins, the residential class would receive a $24.8 million increase to achieve the overall jurisdiction S/W CP ROR.

Witness Haynes explained that witness O'Donnell's 1CP method is unreasonable for the same reasons as the peak only S/W CP method. Witness Haynes testified that 1CP also fails to take into consideration both the summer and winter peaks as DNCP is forecasted to remain a summer peaking utility, but recently experienced all-time system peaks during the winter in 2014 as well as during the 2015 test year. Finally, witness Haynes testified that use of the 1CP method would also increase cost responsibility for the North Carolina jurisdiction, while lowering the rate of return for the jurisdiction, and would also significantly shift costs to the residential class compared to the SWPA method.

Witness Haynes also explained that DNCP's continued use of the test year system load factor is a reasonable, reliable, and consistent method for establishing the weighting of the peak and average components of the SWPA COS methodology. Contrary to witness Goins' view, the Company's use of the system load factor is not arbitrary, but is based on DNCP's actual verified usage of the Company's generation capacity throughout the course of the test year relative to installed capacity. Witness Haynes testified that witness Goins' recommendation to weight the peak demand at 75% and the average demand at 25% is both arbitrary and results oriented as it would have the effect of increasing the residential class' percent of system responsibility for production costs by 13.8% and decreasing the cost responsibility allocated to Nucor by 35.2%.

Finally, witness Haynes argued that the Commission's recent decision in Duke Energy Progress' 2013 rate case adopting a 1CP method for that utility, should not have bearing on the Commission's determination of the appropriate allocation methodology for DNCP. Witness Haynes pointed out that the Commission explained in its Order in the Duke Energy Progress 2013 rate case that cost allocation does not lend itself to a "one size fits all approach."[20] Witness Haynes also emphasized that the use of S/W CP or another peak only method is potentially more significant for DNCP than other utilities due to the Company's obligation to serve a "one-customer industrial class" – Schedule NS – which used approximately 19% (863,206,000) of the 4,568,385,000 jurisdictional kWh during the test year but can also significantly reduce its demand on the peak.

Under cross-examination by CUCA, witness Haynes accepted that adopting a peak-only methodology such as S/W CP or 1CP would allocate a significantly lower amount of cost responsibility to large high load factor customers, but argued that these methodologies would also cause a shift in cost responsibility to the residential and other non-industrial rate classes. He testified that using only one or two hours of the year to determine cost responsibility is not consistent with the way DNCP plans and operates its generation plants, nor is it fair from a cost allocation perspective, especially considering smaller general service and residential customers. During cross-examination by Nucor's counsel, witness Haynes disagreed with witness Goins' alternative weighting of the SWPA demand and energy components at 75% demand and 25% energy, explaining that his rebuttal Schedule 1 analysis showed that this modified weighting would make residential cost responsibility go up by 13.8%, while Nucor would receive a minus 35.2% shift in cost responsibility and the 6VP class would have a negative 28.9% shift in responsibility under this weighting. On redirect, witness Haynes identified other jurisdictions that use average components in allocating production costs but stated that the Company had not completed an exhaustive assessment of every jurisdiction and utility in the country. He also testified that while it is up to the Commission to determine the weightings in SWPA, the Commission has previously determined that the use of the system load factor was an appropriate way to weight the average demand component, and one minus that system load factor was an appropriate way to weight the peak demand component.

In its post-hearing Brief, CUCA contends that use of the SWPA methodology, as opposed to the 1CP, results in a rate design that sets higher rates than required for large industrial customers. Further, CUCA notes that the Commission has approved the use of 1CP for Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC.

The Commission finds and concludes that DNCP has carried its burden of proof to show that the SWPA methodology is the most appropriate cost of service methodology to use in this proceeding to assign cost responsibility for production plant to the North Carolina jurisdiction and the Company's customer classes. On this issue, the Commission gives substantial weight to the testimony of Company witness Haynes and Public Staff

[20] Application of Progress Energy Carolinas, Inc., Docket No. E-2, Sub 1023, Order Granting General Rate Increase, at 98 (May 30, 2013).

witness Floyd. The cost of service methodology employed in establishing an electric utility's general rates should be the one that best determines the cost causation responsibility of the jurisdiction and various customer classes within the jurisdiction based on the unique characteristics of each class's peak demands and overall energy consumption. Company witness Haynes testified extensively that the Company's investment in generating plant, including the recently placed in service Warren County CC and Brunswick County CC, are designed to meet the Company's system peaks and to deliver low cost energy throughout the year. Witness Haynes explained that the SWPA methodology appropriately recognizes that DNCP's system planning is designed to meet both the Company's peak and average system demands and energy needs of customers throughout the year. Both Company witness Haynes and Public Staff witness Floyd testified that the SWPA method appropriately matches allocation of production plant with DNCP's generation planning and operations. The Commission finds that, for purposes of this proceeding, the SWPA cost of service methodology properly recognizes the manner in which DNCP plans and operates its generating plants to provide utility service to customers in North Carolina.

The Commission also recognizes and reaffirms its prior determination in the Duke Energy Progress 2013 rate case that cost allocation does not lend itself to a "one size fits all approach."[21] Based on the facts in this case, a methodology that does not properly consider the effect of overall energy consumption, but focuses mainly on peak responsibility would not properly represent the way in which the Company plans for and provides its utility service and the way customers use that service.

The Commission is not persuaded that either the S/W CP methodology or the 1CP methodology is appropriate for the Company in this proceeding. Company witness Haynes and Nucor witness Goins provided calculations to compare the rates of return associated with the cost of service methodologies they advocated. The disparity between allocation factors for peak demand-related factors and energy-related factors is apparent for each methodology, with the SWPA resulting in the most equitable sharing of the rate of return among DNCP's customer classes in this case.

In Nucor's Brief, Nucor reiterated witness Goins' testimony that (1) the Commission should abandon the SWPA methodology, (2) the Commission should adopt the S/W CP methodology, and (3) if the Commission decides to adopt SWPA, it should address two flaws/biases inherent in DNCP's SWPA cost studies. The two flaws alleged by Nucor are (1) energy use is given too much weight, 56%, because peak demand is the primary driver of DNCP's need for additional capacity, and (2) DNCP's use of SWPA creates an asymmetry in DNCP's assignment of fixed production cost responsibility and its average cost recovery of fuel costs.

With regard to increasing the weight assigned to peak demand, Nucor recommends giving a 25% weight to the average demand component and a 75% weight to the peak demand component. In support of this recommendation, Nucor cites the

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[21] Id.

decisions of the Michigan Public Service Commission in two 2015 dockets, one involving DTE Electric Company (Case No. U-17689, Opinion and Order dated June 30, 2015), and the other Consumers Energy Company (Case No. U-17688, Opinion and Order dated June 30, 2015) (collectively, Consumers). Pursuant to Michigan statutory provisions, a 50-25-25 (50% peak demand, 25% on-peak energy use, 25% total energy use) cost allocation method is mandated, unless a party shows that an alternative method would better ensure that rates are equal to cost of service. The purpose of the Consumers proceeding was to determine whether a change in the energy/demand ratios mandated by the statute was warranted. Consumers Energy proposed a 4CP 100-0-0 methodology, whereby costs would be allocated based 100% on peak demand. However, the PSC Staff recommended a 75-0-25 methodology, which the PSC ultimately adopted. The PSC cited extensive evidence on the appropriate allocation formula, stating

> [T]he Commission therefore finds that the Staff's proposal to modify the production cost allocation method from 50-25-25 to 75-0-25 is well supported, better ensures rates are equal to cost of service, and should therefore be approved.

Id., at p. 17.

The Commission is not persuaded on the present record that the Michigan PSC's approach advocated by Nucor should be adopted for DNCP. For reasons perhaps unique to Michigan, the legislature has mandated that the Michigan PSC use a 50-25-25 cost allocation ratio, unless a better methodology is shown. In contrast, DNCP established its 56%-46% ratio based on DNCP's system load factor test-year data. That process is a more direct and accurate approach than the "one size fits all" ratio mandated in Michigan's statute. In addition, Nucor did not support its 25%-75% allocation weighting proposal with sufficient analyses of DNCP's system operating characteristics.

As a result, the Commission is not convinced that Nucor witness Goins' proposal to reject the Company's use of the system load factor and to adopt Nucor's alternative proposal to establish weighting for the peak demand component at 75% or greater and the average demand component at 25% or less is reasonable or appropriate in this proceeding. Nucor's rationale for this modified SWPA method is that reweighting SWPA to shift significantly greater emphasis to the peak demand component would mitigate the "numerous flaws" that Nucor finds in the SWPA method. Because the Commission finds that the SWPA method is not unreasonable or flawed, the Commission does not find Nucor's argument persuasive. Further, based on the evidence of record in this case, the Commission finds that the system load factor is not arbitrary, but is reasonably based on DNCP's actual verified usage of its Company's generation capacity throughout the course of the test year relative to installed capacity. Nucor's request that the Commission select weighting with a peak demand component of 75% or greater and the average demand component at 25% or less would be unreasonable and, indeed, arbitrary as it is not tied to any objective measurement of DNCP's system operations.

Based on the Stipulation and the testimony on the record, the Commission also finds that including the distribution-interconnected NUG generation in the average portion of the SWPA, but not including this NUG generation in the Company's recorded summer and winter peaks creates a mismatch between the peak and average components of the Company's SWPA COSS. The Commission concludes that the Company's adjustment to the summer and winter peaks to recognize the NUG generation at the distribution level appropriately recognizes the impact the NUGs have on DNCP's utility system and should be approved.

Finally, it is also notable that CIGFUR I joined in the Stipulation with DNCP and the Public Staff supporting the SWPA methodology as reasonable and appropriate in this proceeding. Although CIGFUR I has historically opposed the use of a production plant allocation methodology based on jurisdiction and customer class energy usage, it is not unreasonable for the Stipulating Parties to have agreed, as part of their overall settlement of all contested issues, that the allocation of production plant based on the SWPA methodology is reasonable for purposes of this proceeding. As the Commission has noted, that is part of the give-and-take of settlement negotiations. Therefore, based upon consideration of the Stipulation in its entirety, the Commission gives the Stipulation substantial weight in resolving the cost allocation methodology issue.

Based on the evidence in this proceeding, including the Stipulation, the Commission finds and concludes that the greater weight of the evidence shows that the SWPA cost of service methodology provides the most appropriate methodology to assign fixed production costs by incorporating DNCP's seasonal peak demands at the two single hours they occur and by incorporating the total energy consumed by the jurisdiction and customer classes over all the other hours of the year. In addition, the Commission finds good cause to require that the Company should continue to file a cost of service study using the SWPA methodology annually with the Commission.

Further, the Commission emphasizes the importance of properly allocating costs between jurisdictions, and specifically in this case between Virginia and North Carolina, and between customer classes. In that regard, the Commission takes note of Company witness Haynes rebuttal testimony that "The Company has used the A&E cost allocation method in every Virginia rate proceeding dating back to 1972. The 'average' portion of the A&E method is similar to the 'average' portion of the SWPA method." (T Vol. 7, at p. 193) However, even though the "average" portion of the A&E method is similar to the "average" portion of the SWPA method, the Commission finds good cause to require the Company to file an A&E cost allocation methodology in its next North Carolina general rate case, in addition to the methodology proposed by the Company.

Finally, the Commission notes that there is ample opportunity under Commission rules for thorough consideration of all issues related to cost of service in a general rate case. Interested parties may intervene, conduct discovery and present evidence in accordance with the rules of practice and procedure established by the Commission.

Treatment of Nucor in the Company's Cost of Service

The Company's SWPA cost of service study (Form E-1, Item 45) followed the same approach for the Schedule NS customer class (NS Class), as well as all other classes, used in the cost of service studies filed and approved in DNCP's two most recent general rate cases, Docket No. E-22, Sub 479 in 2012 and Docket No. E-22, Sub 459 in 2010. Specifically, as described by Company witness Haynes, the Company used both a summer and winter peak demand for the NS Class that reflected Nucor's measured demand and recognized the interruptible nature of Nucor's arc furnace pursuant to the confidential terms and conditions of the Company's contract with Nucor, the only customer in the NS Class. The 43 MW of peak demand assigned to the NS Class represents the average of the winter and summer peaks of the NS Class at the time of the test year system winter and summer peaks. These peak demands were used to develop the production plant and transmission related demand allocation factors. The Company also used Nucor's actual test year energy consumption of 863,206,000 kWh to develop the average component of SWPA.

In addition to his alternative COSS recommendations, addressed above, Nucor witness Goins argued that Nucor's total load is "non-firm" or interruptible pursuant to the Company's contract with Nucor for electric service and recommended that the Commission reject DNCP's treatment of Nucor's interruptible load in its cost of service study. Witness Goins disagreed with DNCP's characterization that Nucor's load continues to be partially interruptible under the Nucor agreement and argued that rates for service to fully interruptible customers should not recover any fixed production costs.

Witness Goins asserted that because Nucor's load is interruptible, it is not responsible (except by administrative fiat) for DNCP's fixed production costs. He concluded that service to Nucor's interruptible load occurs only when excess capacity used to serve firm load is available. Witness Goins further argued that DNCP's SWPA method allocates fixed production costs to Nucor almost exclusively based on Nucor's energy use. In contrast, about 60% of fixed production costs allocated to North Carolina customers in DNCP's cost studies is allocated on the basis of energy. Witness Goins recommended that if the Commission adopts DNCP's SWPA method, then the Commission should also replace DNCP's system load factor weighting scheme with peak demand component weights equal to or greater than 75% and average demand component weights of 25% or less, and further require DNCP to: (1) investigate the SWPA's asymmetrical allocation problem, including the preparation and filing for review of a detailed analysis of the problem similar to the analysis the Commission ordered in Docket No. E-22 Sub 333 (1994 Fuel Study); and (2) require DNCP in future jurisdictional and class cost studies to exclude Nucor's interruptible load in developing allocation factors for fixed production costs.

In rebuttal, Company witness Haynes explained the Company's reasoning for characterizing the Nucor agreement as partially interruptible as well as for the Company's treatment of Nucor in DNCP's COSS. Witness Haynes stated that Nucor's total load is only subject to interruption during system emergencies, when all other customers' load is also subject to interruption. Witness Haynes testified that the confidential terms of the Nucor agreement only allow for curtailment of Nucor's arc furnace load during very limited hours and, in certain of those hours, allow Nucor to buy through the curtailment at a higher price. Witness Haynes stated that the Company reads and applies the Nucor agreement to require Nucor's non-furnace load to be treated as "firm" and supplied with firm power throughout the year. Company witness Haynes also testified that he reviewed Nucor's actual loads since DNCP's 2012 Rate Case and confirmed that Nucor's non-furnace load has not been interrupted for emergency situations during at least that period.

Based on his understanding of the terms of the Nucor agreement as well as DNCP's implementation of the agreement since at least 2012, witness Haynes stated that DNCP's SWPA method properly takes into account Nucor's interruptibility, while also recognizing the demands Nucor places on the system and the energy consumed by Nucor. Nucor's average Summer/Winter coincident peak demand was approximately 43,192 kW during the test year, which represented the non-furnace load that the Company maintains is load that was actually served during the summer and winter peak hours. With regard to the average demand component, the Company has an obligation to serve Nucor each hour of the year and such a requirement is measured by the energy consumed. If Nucor is interrupted in any hour, then the energy consumption for that hour would reflect the interruption. Nucor actually consumed approximately 19% (863,206,000) of the 4,568,385,000 jurisdictional kWh during the test year. Witness Haynes asserted that the average demand component should reflect Nucor's actual use of the dispatch of the system generation and purchased power – just as is the case for all other customers.

Witness Haynes also performed an analysis detailing how recognizing Nucor's curtailed demand in developing the allocation methodology provides a significant and properly recognized financial benefit to Nucor as well as a lower overall allocation of system costs to the North Carolina jurisdiction. He asserted that the Company's SWPA allocation factors were calculated in a reasonable manner – consistent with the principles approved in DNCP's 2012 Rate Case – that appropriately recognizes the value of Nucor's interruptibility to the system and does not overstate cost nor understate returns for the North Carolina jurisdiction and its customer classes. Cost responsibility has been properly and fairly determined based on requirements placed on the system – by Nucor and all other customer classes – on the summer and winter peak days and throughout the year.

Witness Haynes also explained that the Commission is reviewing the same curtailment provisions that it reviewed in 2012 when it determined that the Company's SWPA method properly recognized Nucor's interruptible load under the Nucor agreement.

In response to Nucor's recommendation that the Commission require DNCP to exclude 100% of Nucor's load as interruptible in developing allocation factors for fixed production costs in future jurisdictional and class COSS, witness Haynes explained that this recommendation is inappropriate and, in effect, would treat the Schedule NS Class as if it did not exist. Witness Haynes explained that such an approach would be inconsistent with the manner in which DNCP has provided service to Nucor since the 2002 amendment to the Nucor agreement, when Nucor requested to transition from marginal cost of fuel and no assigned production plant to average cost of fuel for all system production resources. Haynes explained that if a customer once paid marginal cost and a small margin contributed toward production plant and related costs and now pays a more "certain" average fuel cost, then it should also be responsible for production plant costs – similar to all other customers.

Witness Haynes also reiterated that the provisions of the operative Nucor agreement giving Nucor the benefit of average fuel today are identical to the provisions of the Nucor agreement the Commission reviewed in 2012, when the Commission stated on page 30 of its Order as follows:

> The Commission also notes that the 2002 amendment to the Nucor contract to change the pricing structure was made at the request of Nucor. Nucor sought certainty in its pricing arrangements. Nucor therefore opted for a pricing arrangement that was based on the average fuel costs of the system, rather than the marginal cost pricing structure it had been receiving since the inception of the contract. ***The Commission agrees with the Company that under such an arrangement Nucor elected to receive the benefit of average fuel costs, and in doing so it also should be responsible for a share of the fixed production costs required to produce those same average fuel costs.*** The Commission further notes that the Nucor contract filed in the 2010 general rate case, Docket No. E-22, Sub 459, and in this proceeding no longer contains the language relieving the Company of any responsibility to provide for capacity to serve Nucor. (Emphasis added.)

In opposition to witness Goins' recommendation that Nucor be treated as 100% interruptible in future cost of service studies, witness Haynes concluded that Nucor actually consumes energy produced by DNCP equivalent to the energy needs of 71,000 residential households and because the NS Class is using production plant, it should contribute to fixed costs.

Based on the entire record in this proceeding, including the Stipulation, the Commission is persuaded that the Company has treated the NS Class and Nucor appropriately in its cost of service study and that no additional recognition of the benefits associated with the Nucor contract should be made in this proceeding.[22]

The facts and evidence in this proceeding show that the Company has consistently followed the same approach in this case of recognizing the benefits of Nucor's interruptibility – to both Nucor and the North Carolina jurisdiction – consistent with DNCP's

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[22] In arriving at this conclusion, the Commission takes judicial notice of its most recent general rate case order for DNCP, issued on December 21, 2012 in Docket No. E-22, Sub 479. Specifically, the Commission recognizes its findings and conclusions regarding the interruptibility provisions of the Nucor Agreement and Schedule NS in that proceeding, which were ultimately affirmed on appeal by the North Carolina Supreme Court in <u>State ex rel. Utils. Comm'n v. Cooper</u>, 367 N.C. 430, 758 S.E.2d 635 (2014).

approach in the Company's past two general rate case proceedings. Further, the record in this case is undisputed that the curtailment provisions in the Nucor agreement have not been modified since last reviewed by the Commission in 2012. The Commission again concurs with the Company, Nucor, and Public Staff witnesses that the system, and the NS Class in particular, benefits from only recognizing Nucor's non-arc furnace load in calculating the peak load of the NS Class in the cost of service. Nucor's contract with the Company provides Nucor with flexibility in deciding how and when it consumes energy for the vast majority of hours in the year. Outside of the relatively few hours the Company can contractually request Nucor to curtail its arc furnace load, Nucor is free to buy through all other requests at a fixed price arrangement. The Company's testimony that Nucor's non-furnace load has not been interrupted since at least 2012 is also undisputed. Accordingly, based upon the facts and evidence presented in this case, the Commission does not find Nucor's arguments that the Nucor agreement is totally interruptible to be persuasive nor does the Commission find that Nucor should be treated differently than other customer classes and relieved of paying for its allocated share of DNCP's investment in production plant.

The Commission also again notes that the 2002 amendment to the Nucor contract to change the pricing structure was made at the request of Nucor. Nucor sought certainty in its pricing arrangements. Nucor therefore opted for a pricing arrangement that was based on the average fuel costs of the system, rather than the marginal cost pricing structure it had been receiving prior to 2002. The Commission agrees with the Company that under its current contractual arrangement Nucor has elected to receive the benefit of average fuel costs, and in doing so, it also should be responsible for a share of the fixed production costs required to produce those same average fuel costs. The Commission further notes that the Nucor contract, most recently approved by the Commission in Docket No. E-22, Sub 517, no longer contains the language relieving the Company of any responsibility to provide for capacity to serve Nucor as was the case of the Nucor contract prior to 2010. As the Commission describes below, the Nucor contract provides Nucor the right to continue to receive this partially interruptible service or to work with DNCP to move to another generally available rate schedule.

Based on the same reasons that service to Nucor should not be treated as 100% interruptible in developing the North Carolina cost of service used in setting just and reasonable rates in this case, the Commission finds and concludes that it would similarly be unreasonable and inappropriate to direct DNCP to make this assumption in future cost of service study filings with the Commission, unless the contract with Nucor is significantly altered such that it supports that position.

Fuel Study

In his testimony, Nucor witness Goins asserted that use of the SWPA methodology creates a mismatch in allocating fixed production costs and variable fuel costs. He stated that because high load factor customers are allocated a disproportionate share of DNCP's fixed production costs, they should also be allocated a disproportionate share of cheaper energy costs associated with the higher cost capacity. Instead, DNCP allocated average fuel costs on the basis of class loss-adjusted energy use. In other words, higher load factor classes get the higher baseload plant costs, but not the corresponding savings from lower baseload fuel costs. Witness Goins noted that in the 1994 Fuel Study, DNCP concluded that traditional average fuel cost recovery is not symmetrical with the way the LGS class is allocated production-related cost under the SWPA method. He recommended that the Commission require DNCP to prepare and file a detailed analysis similar to the analysis undertaken in the 1994 Fuel Study.

Witness Haynes testified in opposition to witness Goins' recommendation that DNCP be required to develop a new analysis similar to the 1994 Fuel Study. He explained that all customers, including residential and large industrial, benefit when the utility's system of available generating resources is operated such that the units with the lowest possible variable cost (mostly fuel) are dispatched to serve customer loads not just in the summer and winter peak hours, but in all hours of the year. This lowers fuel expenses recovered through the fuel clause. The capability to lower fuel expenses throughout the course of the year by system dispatch is accomplished by having available resources to efficiently serve utility loads during all hours and not only during the summer and winter peak hours. If all classes of customers are effectively paying "average fuel cost," then all customers are getting the benefit of the integrated system operation of the full range of generation resources from high capital cost/low operating cost generation to low capital cost/high operating cost generation.

Witness Haynes further testified that the SWPA method produces reasonable results by considering two seasonal peaks and the average demand and appropriately weighting both. DNCP's system load factor is approximately 56%, so the peak demand component is weighted at 44% in calculating the final total allocation factor. Witness Haynes stated that with this 44% weighting of the average of the winter and summer peaks and the ability of high load factor classes in North Carolina to reduce load during peak hours, such customers can reduce, and do reduce, their responsibility for fixed production costs. Witness Haynes testified that this a fair and reasonable approach to determining responsibility for fixed costs while paying average fuel. Witness Haynes therefore testified that there was no reasonable basis for the Commission to require the Company to "re-do" the 1994 Fuel Study.

Witness Haynes also testified during the hearing that DNCP has developed new industrial rate designs since 1994, such as Schedules NS and 6VP that allow high load factor classes in North Carolina to reduce load during peak hours, which has the effect of reducing these customer classes' responsibility for fixed production costs under the Company's SWPA method.

In Nucor's Brief, Nucor reiterated witness Goins' testimony that DNCP's use of SWPA creates an asymmetry in DNCP's assignment of fixed production cost responsibility and its average cost recovery of fuel costs. Witness Goins testified that because higher load factor customers are allocated a disproportionate share of DNCP's fixed production costs (including the higher cost of intermediate and baseload generating plants) under the SWPA methodology, they also should be allocated a disproportionate share of cheaper energy costs associated with the higher cost capacity. According to witness Goins, fixed production costs and variable fuel costs are not allocated symmetrically in DNCP's cost studies.

However, the Commission gives significant weight to the rebuttal testimony of DNCP witness Haynes. He testified that all customers, including residential and large industrial customers, benefit by DNCP's method of dispatching its generating resources such that the units with the lowest possible variable cost (mostly fuel) are dispatched to serve customer loads not just in the summer and winter peak hours but in all hours of the year. This lowers fuel expenses that are recovered through the fuel clause. Witness Haynes stated that the capability to lower fuel expenses throughout the course of the year by system dispatch is accomplished by having available resources to efficiently serve utility loads during all hours of the year, not solely during the summer and winter peak hours. He asserted that when all classes of customers are effectively paying "average fuel cost" determined in fuel clause proceeding, then all customers are getting the benefit of the integrated system operation of the full range of generation resources from high capital cost/low operating cost generation to low capital cost/high operating cost generation.

Further, in the Stipulation, DNCP, the Public Staff, and CIGFUR I agreed that it is unnecessary at this time for the Company to re-evaluate the issues reviewed in the 1994 Fuel Study.

The Commission notes that cost responsibility based on energy (kWh) allocation has been deemed to produce just and reasonable rates in DNCP's past fuel proceedings. Further, the Commission agrees with DNCP and the other Stipulating Parties, including CIGFUR I, that it is unnecessary at this time to require DNCP to develop an analysis similar to the 1994 Fuel Study. The 1994 Fuel Study analysis preceded Nucor's arrival on to DNCP's system in 2000, Nucor's request in 2001 to transition to a more certain average fuel rate (similar to all other customers), and the subsequent 15 years of history, which informs the Commission's current understanding of DNCP's service to Nucor. In addition, with the weighting of the average of the winter and summer peaks and the ability of high load factor classes in North Carolina to reduce load during peak hours, such customers can reduce, and do reduce, their responsibility for fixed production costs. The Commission concludes based upon the record in this case that it is unreasonable and unnecessary to require DNCP to complete an analysis similar to the 1994 Fuel Study.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 42

The evidence for this finding and these conclusions is found in the Application, the testimony of Company witness Haynes, Public Staff witness Floyd, and Nucor witness Goins, and the Stipulation, and all other evidence of record.

The Application and the testimony and exhibits of Company witness Haynes explain how DNCP proposed to apportion the jurisdictional revenue requirement established using the Company's SWPA jurisdictional and class COSS amongst the customer classes. Witness Haynes' testimony and exhibits assigned the revenue requirement to specific rate schedules and then calculated the percent increase that customers on each rate schedule would experience.

In apportioning the revenue requirement among the customer classes, witness Haynes identified general and class-specific principles that the Company used to equitably distribute the base rate revenue increase, including: (1) all classes should share in the non-fuel base rate revenue increase in a manner that moves each class of customers closer to parity with the North Carolina jurisdictional ROR; (2) for classes outside of a reasonable return index range of 0.90 and 1.10 (Parity Index Range), an effort must be made to more reasonably align the rates customers pay with their responsibility for cost, even if the index achieved after apportionment still remains outside of the Parity Index Range; (3) for purposes of apportioning the increase for the LGS and 6VP classes, the two classes are combined to treat large industrial customers within these classes in the same manner and also to recognize certain non-cost factors that support a lesser increase for large industrial customers with high load factors within these classes; and (4) for purposes of apportioning the increase to the NS Class, the Company balanced the need to equitably address certain legacy economic development rate (EDR) subsidy issues with the unique nature of the Company's electric service arrangement with its largest and most energy-intensive customer, Nucor.

Specific to the non-cost considerations that DNCP took into account in apportioning the revenue increase among the industrial customer classes, witness Haynes testified that he considered the quantity and timing of large industrial manufacturing customers' electric usage in their industrial operations, as well as factory utilization and the economic vitality of the Company's North Carolina service territory, as it relates to these industrial customers.

Witness Haynes presented an extensive history of the Company's agreement with Nucor under which DNCP provides electric service to Nucor, beginning with its approval as an EDR in 1999, and then noted DNCP's concern with the legacy rate of return (ROR) index deficiency in Nucor's contribution towards the Company's cost of service. Witness Haynes explained that the Schedule NS rate design has been beneficial to DNCP's operation of its system, as well as to the North Carolina jurisdiction and to Nucor, and stated that recognition of the partially interruptible nature of service to Nucor's arc furnace under Schedule NS and the Nucor agreement is consistent with North Carolina's policy that a utility may design different rates for different customers based upon differences in conditions of service. Witness Haynes testified that the Company is not opposed to continuing Schedule NS and the Nucor agreement in its current form (subject to Nucor electing otherwise, as discussed below), but that continuing the deficiency in the NS Class' rate of return index, and Nucor's deficient contribution to DNCP's cost of service represents an increasingly inequitable legacy benefit of the initial EDR. Witness Haynes explained that this legacy EDR benefit has extended well past the period originally contemplated in 1999, and significantly longer than the four-year term of EDRs offered to other customers. Accordingly, the Company's Application increased the NS Class ROR index from 0.44 to 0.74, which would move the NS Class two-thirds of the way towards the low end of the Parity Index Range (90% of jurisdictional ROR).

Company witness Haynes also testified that while DNCP developed its allocation and rate design proposals based upon the assumption of continued service, inclusive of the requested base rate increase, under current Schedule NS and the existing Nucor agreement, DNCP also provided notice to Nucor of its intent to terminate the existing Nucor agreement as of December 31, 2016, in order to explore whether Nucor is interested in modifying the current Nucor agreement, or alternatively, receiving service under another available DNCP rate schedule.

Public Staff witness Floyd recommended a more generalized approach to apportioning the revenue increase and designing rates, consistent with the approach and considerations that the Public Staff recommended and the Commission adopted in the Company's 2012 Rate Case. Specifically, witness Floyd recommended that the Commission look at changes to base non-fuel and base fuel revenues together and apply the following principles in spreading the impact to base non-fuel and base fuel revenues: (1) employ a +/- 10% "band of reasonableness" relative to the overall jurisdictional ROR such that, to the extent possible, the class ROR stays within this band of reasonableness following revenue assignment after the rate changes; (2) limit the combined base fuel and base non-fuel revenue increase to no more than two percentage points greater than the overall jurisdictional revenue percentage increase; and (3) minimize subsidization of customer classes by other customer classes.

Nucor witness Goins developed a revenue spread premised on the Commission's adoption of his proposed S/W CP methodology that took into account the following principles: 1) set base rates to bring the ROR for each class within plus or minus 10% (±10% constraint) of the system average ROR; 2) allow no base rate decrease for any class; and 3) limit the base rate increase for any class to no more than 1.5 times the system average increase (1.5x constraint) at a 7.80% ROR. According to Goins' analysis, using S/W CP, the proposed increase would be borne by residential and small general service customers, while other classes would receive no non-fuel base rate increase.

In rebuttal, Company witness Haynes critiqued the proposed revenue apportionment presented by Public Staff witness Floyd. He explained that while certain of witness Floyd's rate design considerations are reasonable from a policy perspective, the Company's significantly more detailed fully-adjusted approach to revenue apportionment and rate design is more reasonable and appropriate. In response to Nucor witness Goins' revenue spread proposal, witness Haynes explained that the rates of return based upon witness Goins' fully adjusted cost of service using the S/W CP method differ dramatically from the Company's results using SWPA, resulting in a significant shift in allocated responsibility for production plant, net operating income and the resulting rate of return. Specifically, he explained that allocated rate base responsibility for the residential class would be 17% higher under witness Goins' proposal and that residential rates must go up by $29.37 million in order to bring the residential class to an equal rate of return with the jurisdiction.

Witness Haynes affirmed the Company's support for its initial proposal to increase non-fuel base revenue for the NS Class two-thirds of the way to the bottom of the rate of return index Parity Index Range (0.90 to 1.10). Witness Haynes testified that DNCP's proposed revenue apportionment and rate design strikes a reasonable balance between Nucor and other customers and does not result in an unreasonable increase or "rate shock" to Nucor, as Nucor's overall rates will decrease on January 1, 2017 as a result of this case.

In the Stipulation, DNCP, the Public Staff, and CIGFUR I agreed that the stipulated overall $25.790 million increase in base non-fuel and decrease in base fuel revenues should be apportioned consistent with the rate design principles presented by Company witness Haynes in his direct and rebuttal testimony, subject to the Stipulating Parties' further agreement that: (1) all classes should share in the non-fuel base rate revenue increase in a manner that moves each class of customers closer to parity with the North Carolina jurisdictional rate of return; (2) the 6VP class Rate of Return Index will be 1.15; and (3) the NS Class Rate of Return Index will be 0.75, which moves the NS Class two-thirds of the way towards the low end of the Parity Index Range of 0.90 and 1.10.

Based on the Stipulation and the evidence in the record, the Commission concludes that for purposes of this proceeding it is appropriate to apportion the proposed base fuel and non-fuel revenue increase approved in this Order using the methodology recommended by DNCP as modified by the Stipulation. The Commission agrees with the Public Staff, Nucor, CIGFUR I, and the Company that revenue should be distributed so that class rates of return are close to the overall jurisdictional rate of return, whenever possible. Further, the effects of rate shock and other economic and inter-class conditions should also be considered. The Commission believes that the principles employed by Company witness Haynes, as modified by the Stipulation, appropriately balance these objectives.

The Commission also recognizes that DNCP provided notice to Nucor on March 1, 2016, of the Company's intent to terminate the existing Nucor agreement as of December 31, 2016, in order to explore with Nucor whether the customer would be interested in modifying the current Nucor agreement, or alternatively, receiving service under another available DNCP rate schedule, consistent with the terms of the Nucor agreement. Based upon the record in this proceeding, no changes have been proposed to the existing terms and conditions of Schedule NS and the Commission accepts DNCP's position as undisputed that the current Schedule NS rate design and partially-interruptible service to Nucor under the Nucor agreement has been beneficial to DNCP's operation of its system, as well as to the North Carolina jurisdiction and to Nucor. Based on the entire record in this proceeding, the Commission finds and concludes that DNCP should offer Nucor service pursuant to the terms and conditions of Schedule NS and the Nucor agreement approved on March 29, 2016 in Docket No. E-22, Sub 517, as modified to reflect the authorized change in non-fuel base revenues.

Basic Customer Charge

In his testimony, Public Staff witness Floyd discussed the Company's proposed changes to the basic customer charge. He explained that the unit cost data in Item 45e is an approximation of the cost associated with each unit of service for a given utility function and provides an indicative benchmark to use when designing individual rate elements of various rate schedules. Witness Floyd compared the unit cost data in this proceeding to similar data from the 2012 Rate Case and found that those costs designated as "customer" unit costs have decreased since the 2012 Rate Case. This review suggested to him that the basic customer charges currently approved for DNCP rate schedules are greater than the "customer" designated unit costs found in Item 45e. Witness Floyd therefore recommended that none of DNCP's basic customer charges be increased.

In his rebuttal, Company witness Haynes accepted witness Floyd's recommendation with the understanding that any needed revenue apportionment to the rate schedules would be apportioned to the other charges in the rate schedules. The Stipulation provides that in developing rates based upon the class apportionment agreed to in the Stipulation, the Company agrees to recover 100% of the stipulated revenue increase through the energy and demand components of rates and not to increase the basic customer charge component of rates. The Commission finds this provision of the Stipulation to be reasonable and appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 43

The evidence for this finding of fact and these conclusions is found in the Application, the testimony of DNCP witness Haynes and Public Staff witness Floyd and the Stipulation.

The Company's Application proposed new Large General Service Schedule 6L, which is designed as an additional rate option for DNCP's large industrial customers in addition to existing rate schedules 6C, 6P, 6VP, and 10.

Company witness Haynes explained that the Company developed Schedule 6L in response to recent concerns expressed by DNCP industrial customers that the current industrial Schedule 6P rate is less preferable compared to rate options available in other utilities' service territories. He presented an example showing how the design of rates can impact economic competitiveness and factory utilization and potentially may cause a hypothetical industrial customer in DNCP's North Carolina service territory to consider moving production to a facility located elsewhere in order to lower its electricity bill and thus lower its cost of production. Witness Haynes described the new Schedule 6L as a potentially more advantageous option than existing Schedule 6P for "high load factor" customers that place demands on the Company's system during most if not all hours of the day for seven days per week, and generally maintain annual load factors of approximately 80% and higher. Witness Haynes testified that the new optional Schedule 6L would be applicable to large industrial customers that have achieved a demand of at least 3,000 kW in the three billing months during the most recent 12-month period.

Witness Haynes explained that Schedule 6L is designed to recover more costs through demand charges and less through energy charges when compared to existing Rate Schedule 6P. Witness Haynes also explained that the Company has amended the Company's Rider EDR tariff to include Rate Schedule 6L as an eligible rate schedule. The Company proposed to continue to offer Rate Schedule 6P, as this schedule is appropriate for industrial and commercial customers that do not have an extensive need for electricity around the clock.

Public Staff witness Floyd recommended that the Commission approve proposed Schedule 6L, subject to one change in the tariff language to eliminate the NAICS "Manufacturing" classification as part of the qualification for this rate schedule. Witness Haynes testified in rebuttal that the Company agrees with witness Floyd's proposed change and that the specific NAICS "Manufacturing" classification eligibility limitation had been eliminated in the revised Schedule 6L included as Company Rebuttal Exhibit PBH-1, Schedule 12.

During the hearing, witness Haynes further explained that over the last 10 to 12 years, the Company has developed new rates and structures to address concerns of industrial customers. He testified that about 10 years ago, the Company developed a new Schedule 6VP rate to recognize that some large industrial high usage customers had the ability to curtail in certain hours given a price signal. He explained that proposed Schedule 6L is designed in response to the needs of certain high load factor customers and would recover more costs in the demand component. Under Schedule 6L, the average cost to a high load factor customer under Schedule 6L will be approximately 5.7 cents/kWh. Witness Haynes also testified that DNCP's industrial rates are competitive in North Carolina and significantly lower than industrial customer rates across the EEI South Atlantic region.

The Commission finds and concludes based upon all evidence in the record that Rate Schedule 6L, as presented in Company Rebuttal Exhibit PBH-1, Schedule 12 is reasonable and nondiscriminatory, and should be approved. No party objected to the Schedule 6L design, as amended by DNCP to address the Public Staff's eligibility recommendation. Further, no party disputed witness Haynes testimony during the hearing that certain of the Company's high load factor customers could benefit from the Schedule 6L design.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 44

The evidence supporting this finding of fact and these conclusions is contained in the Application, the testimony of Nucor witness Thomas, the direct and rebuttal testimony of Company witness Haynes, the Stipulation, and the entire record in this proceeding.

As described in the Application and the testimony of Company witness Haynes, DNCP develops its COSS for purposes of allocating and assigning the cost of utility service to the North Carolina jurisdiction and between the North Carolina customer classes. Since DNCP's 2012 Rate Case, the Company has evolved its cost of service model from a basic Microsoft Excel-based model to the Utilities International (UI) Model, a subscription software-supported model developed by UI. The UI Model provides the Company a staged database platform through which business units can directly input cost and other source information into the UI Model. The Company's Cost Allocation group then maintains the UI Model and uses to it perform all cost of service-related regulatory functions, including developing the COSS for North Carolina rate cases. During this proceeding, Nucor as well as other parties requested that DNCP run alternative COSS using alternative allocation methodologies to DNCP's SWPA method.

Nucor witness Thomas developed and supported a fully adjusted S/W CP COSS analysis. Witness Thomas explained that he relied upon information provided in discovery by the Company to develop Nucor's fully-adjusted S/W CP COSS analysis, but commented that the Company's transition to the UI Model has caused difficulty for Nucor and parties other than DNCP to run alternative cost of service (COS) analyses. Witness Thomas testified that DNCP held conference calls with Nucor to explain the UI Model and also made the UI Model available upon reasonable notice at the Company's offices in Richmond for in-person inspection. Witness Thomas testified that DNCP's historic use of spreadsheet-based COS models was more usable by Nucor and other parties who could run various scenarios to evaluate and test the impacts of potential changes in allocator methodologies, allocator selections, changes in recommended ratemaking adjustments, changes in revenue requirements, and other scenarios. He also explained that the UI Model uses its own programming language, and that it could take considerable time for someone unfamiliar with the software to learn how to use the software and subsequently audit the software to validate its functionality. Witness Thomas concluded that although Nucor was able to develop a fully-adjusted S/W CP COS model run, his opinion was that the UI Model presents an undue burden on parties in this proceeding and severely limits their capabilities relative to the spreadsheet-based COS models used by DNCP in prior proceedings.

In rebuttal, Company witness Haynes responded that the Company has worked diligently in this case to be supportive of the regulatory process by performing original work to run COSS requested through data requests and motions by CIGFUR I and Nucor, respectively, and also offered to make the UI Model available for inspection at the Company's office in Richmond. Witness Haynes testified that the Company plans to work with Utilities International to determine whether Utilities International can produce an application that would enable an intervenor or the Public Staff to perform certain UI Model functionalities in spreadsheet-based Excel, generally including manipulating allocation factors to prepare their own COSS in future rate case proceedings.

In the Stipulation, DNCP, the Public Staff, and CIGFUR I agreed that the Company will work with Utilities International to determine whether it can produce an application that would enable an intervenor or the Public Staff to perform certain UI Model functionalities in Excel, generally including manipulating allocation factors to prepare their own cost of service studies in future rate case proceedings.

The Commission finds and concludes that the Company has worked in good faith and made reasonable efforts in this case to provide Nucor and other parties with COS-related information through the normal discovery process. The Commission finds that DNCP's commitment in the Stipulation to work with Utilities International regarding assessing reasonable additional COS functionalities that can be produced in an Excel spreadsheet-based format should be completed prior to DNCP filing its next general rate case.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 45

The evidence supporting this finding of fact and these conclusions is contained in the testimony and exhibits of Company witness Haynes and Public Staff witness Floyd and the Stipulation.

Public Staff witness Floyd testified that DNCP does not currently offer customers any lighting services or fixtures that use LED (light emitting diode) technologies. Schedule 26, DNCP's outdoor area and street lighting tariff, only offers mercury vapor and high pressure sodium fixtures. In response to a Public Staff data request, DNCP indicated that it was currently investigating new LED lighting services in conjunction with contract negotiations between the Company's Virginia affiliate and several Virginia municipalities. The Company's response suggested that once these negotiations were completed, and the Company had a better understanding of the LED lighting services that would be covered by those contracts, DNCP could bring new LED lighting services to the Commission for approval. Based on this information, witness Floyd recommended that the Commission require DNCP to either file a request for approval of new LED lighting services and fixtures within one year following the Commission's order in this proceeding or for DNCP to incorporate a new LED lighting services and fixtures rate option in its next general rate case, whichever comes first.

In his rebuttal, Company witness Haynes agreed with witness Floyd's recommendation. The Stipulation provides that the Company agrees to develop and file for Commission approval a new LED schedule for North Carolina jurisdictional customers within one year of the Commission's final order in this proceeding. The Commission finds and concludes that this provision of the Stipulation is reasonable and appropriate and should be adopted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 46

The evidence for this finding of fact and these conclusions is found in the cross-examination of Company witness Haynes by CUCA, and the entire record before the Commission in this proceeding.

During cross-examination by CUCA, Company witness Haynes described Real Time Pricing (RTP) rates. Witness Haynes indicated that a RTP rate is no longer offered to customers in DNCP's service territory in North Carolina. He further stated that if the

Company deemed a RTP rate to be something it wanted to offer its customers, it could bring that forward.

In its post-hearing Brief, CUCA submitted that RTP rates tend to have a significant beneficial impact on high load factor customers. CUCA urged the Commission to require DNCP to propose a pilot RTP rate by July 1, 2017, and to present its RTP proposal for a ruling by the Commission by the end of 2017.

The Commission is of the opinion that an RTP rate, if offered, could provide high load factor customers significant benefits. Therefore, the Commission finds and concludes that it is reasonable to require the Company to propose a pilot or experimental RTP rate offering no later than July 1, 2017.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 47

The evidence supporting this finding of fact and these conclusions is found in the testimony and exhibits of Company witness Haynes, the cross-examination by NCSEA and Commissioner Patterson, and the agreement between DNCP and NCSEA.

Company witness Haynes sponsored Company Exhibit PBH-1, which shows DNCP currently has a combined total of 307 residential customers participating in their Time of Use (TOU) rate tariffs (258 customers for Schedule 1P and 49 customers for Schedule 1T). This represents only 0.3% of DNCP's 102,058 residential customers. This is a decrease from 2007, when 366, or 0.4% of DNCP's residential customers received service under a TOU rate tariff.

In its post-hearing Brief, NCSEA requested that the Commission require DNCP to take three actions with regard to TOU rates: (1) offer a rate comparison and potential savings calculation to residential customers who receive a smart meter; (2) in its next general rate case, include a cost of service study that investigates the impacts of making TOU rates the default rate for new residential customers; and (3) file with the Commission the results of certain TOU pilot projects approved by the Virginia SCC.

On December 13, 2016, DNCP and NCSEA filed a letter with the Commission describing the agreement reached by them on the issues raised by NCSEA regarding TOU rate offerings by DNCP. In summary, the agreement provides that DNCP will file with the Commission and serve on all parties to this docket the final annual report to the Virginia SCC regarding DNCP's Dynamic Pricing Pilot Program and Electric Vehicle Pilot Program in the Company's Virginia jurisdiction.[23] Further, DNCP states that it objects to NCSEA's recommendation that the Company perform a rate comparison for every customer who has received a smart meter and is currently served on a non-TOU residential rate, but that the

[23] Virginia Electric and Power Company's Proposed Pilot Program on Dynamic Rates, Virginia SCC Case No. PUE-2010-00135; Application of Virginia Electric and Power Company for Approval to Establish an Electric Vehicle Pilot Program pursuant to § 56-234 of the Code of Virginia, Virginia SCC Case No. PUE-2011-00014.

Company will agree to investigate improving the rate comparison process for residential customers. This investigation will include studying the feasibility of a web-based tool designed to educate customers about TOU rates and providing tools for residential customers to perform their own rate comparison. The Company agrees to discuss the findings of this investigation with NCSEA by the end of 2017.

In addition, the Company states that it objects to NCSEA's recommendation that the Company default residential customers to a TOU rate. The Company also objects to NCSEA's request that the Company develop an alternative cost of service study methodology for inclusion in a future general rate case application, as such an undertaking would be unduly burdensome. However, DNCP agrees to investigate a way to study the impacts of defaulting new residential customers onto TOU rates in a cost of service study and report to the Public Staff and NCSEA the findings of such a study by October 1, 2017. The Company will conduct this investigation using readily available information prepared for the Company's filing in Docket E-22 Sub 532. Moreover, DNCP will provide to NCSEA consolidated hourly profile information for rate schedules 1P and, separately, 1T.

Finally, the agreement states that NCSEA withdraws the recommendations in its post-hearing Brief in consideration of the Company's commitments as set forth above.

The Commission is sensitive to the impact that any residential rate increase has on utility customers in North Carolina, particularly low-income customers. The Commission wants to ensure that DNCP's customers are fully aware of existing rate tariffs that could help them reduce monthly bills. The Company's response (in part) to the NCSEA Data Request Number 2, Question Number 6, states "Customers who received smart meters were not provided with information about DNCP's TOU rate schedules." The Commission finds and concludes that DNCP should be required to provide a written summary of its TOU rates, and its RTP rates, when developed, to each residential customer presently being served and to be served in the future by a smart meter. In addition, the Commission encourages the Company to investigate opportunities to better educate its customers on the benefits of TOU rates.[24]

In addition, the Commission finds and concludes that the terms of the agreement between DNCP and NCSEA are reasonable, are in the public interest, and should be approved

[24] Report of the North Carolina Utilities Commission Regarding an Analysis of Rate Structures, Policies, and Measures to Promote Renewable Energy Generation and Demand Reduction in North Carolina, Docket No. E-100, Sub 116 (September 2, 2008).

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 48

The evidence supporting this finding of fact and these conclusions is contained in the Application, the testimony and exhibits of Company witness Haynes and Public Staff witness Floyd and the Stipulation.

Item 39 of the Company's Form E-1 filed with the Application and the Company's supplemental direct testimony showed the changes the Company proposed to make to each section of the Terms and Conditions, Rider D-Tax Effect Recovery, Fuel Rider A, and Rider EDR. No party testified in opposition to the adoption of the proposed changes to the Terms and Conditions, and the Stipulation provides that DNCP's Terms and Conditions should be revised as set forth in Item 39 of the Company's Form E-1 filed with its supplemental direct testimony. The Commission finds and concludes that this provision of the Stipulation is reasonable and appropriate and should be adopted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 49

The evidence supporting this finding of fact and these conclusions is contained in the verified Application and DNCP's Form E-1, the testimony and exhibits of Company witness Curtis and Public Staff witness McLawhorn, and the entire record in this proceeding.

Company witness Curtis provided testimony regarding DNCP's performance with regard to customer service. He testified that the Company's generating fleet has demonstrated excellent performance results. He also stated that DNCP continues to provide excellent customer service, and that the Company has improved its North Carolina System Average Interruption Duration Index (SAIDI), excluding major storms performance, by over 20% since 2007, and maintained consistent performance below 120 minutes since 2012. He noted that because of DNCP's previous infrastructure investments, the Outer Banks area continues to be one of the best performing areas across DNCP's entire service territory.

Witness Curtis also testified that the Company continues to achieve excellence in customer service by offering innovative solutions in response to customer expectations, including leveraging technology to perform quick, seamless customer transactions. He noted that DNCP customers completed more than 13 million online transactions during 2015, and that usage of electronic transactions has increased by 61% since 2012. He described the Company's promotion of social media interactions with customers, including its implementation in 2014 of an interactive map that allows customers to view current outages and see details of current outages, such as status and estimated restoration time. Witness Curtis also testified about recognition for outstanding performance that the Company's parent, Dominion Resources, Inc., had received during the past several years.

Public Staff witness McLawhorn testified that the Public Staff had reviewed service-related complaints received by the Public Staff's Consumer Services Division, the

Company's call center operation reports filed with the Commission, SAIDI and SAIFI statistics, the Company's report on new residential service installations, and complaints directly received by DNCP related to vegetation management. Based on the low number of service-related complaints and the relative level of its service metrics, witness McLawhorn found the overall quality of electric service provided by DNCP to retail customers to be adequate.

Based on the testimony of Company witness Curtis and Public Staff witness McLawhorn, the Commission finds and concludes that the overall quality of electric service provided by DNCP is good.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 50

The evidence supporting this finding of fact and these conclusions is contained in the Application, the direct, supplemental, and rebuttal testimony and exhibits of DNCP witnesses Hupp and Bailey, the Company's July 8, 2016 Supplemental Filing, the testimony of Public Staff witness McLawhorn, the Stipulation, and the hearing testimony. In addition the Commission relies on its April 19, 2005 Order Approving Transfer Subject to Conditions in Docket No. E-22, Sub 418 (the PJM Order), and the post-hearing exhibit filed by DNCP.

In the Application, the Company requested relief going forward from the regulatory conditions imposed in the PJM Order. The over-arching goal of the conditions in the 2005 PJM Order was stated as follows: "That Dominion's North Carolina retail ratepayers shall be held harmless from all direct and indirect effects and costs, either related to operations, quality of service, reliability, or rates, arising from its integration with PJM ...."

PJM Order Condition (1)a states that:

> Dominion's North Carolina retail customers shall continue to be entitled to, and receive, cost-based rates for generation, transmission, and distribution (including any ancillary services) determined pursuant to North Carolina law using the same ratemaking methodology as that employed by this Commission as of the time of Dominion's joining PJM notwithstanding Dominion's integration into PJM or decision to participate in any capacity or energy market administrated by PJM; that is, under no circumstances(s) or event(s) shall the costs of generation and transmission, among other things, included in Dominion's N.C. retail rates be greater than the lesser of (1) such costs determined on the basis of historical, embedded costs, calculated consistent with the Commission's currently existing rate base, rate-of-return ratemaking practices and procedures, or (2) the marginal costs of generation and transmission supplied into or purchased from PJM;

PJM Order Condition (1)b states that:

> Dominion shall continue to serve its native load customers in North Carolina with the lowest-cost power it can generate or purchase from other sources

in order to meet its native load requirements before making power available for off-system sales;

PJM Order Condition (1)c states that:

Dominion shall take all reasonable and prudent actions necessary to continue to provide its NC retail customers with the same (or higher) superior level of bundled electric service as that provided prior to Dominion's integration with PJM, including, for example, reliable generation, transmission, and distribution service; and responsive customer service;

PJM Order Condition (1)d states that:

Dominion shall not include in base rates: (a) PJM administrative fees or any replacement mechanism for such fees approved by FERC[25]; (b) PJM transmission congestion costs or revenues from PJM for financial transmission rights (FTRs) or auction revenue rights (ARRs) or any replacement mechanism for such cost and revenues approved by the FERC; (c) any increase in transmission service charges to the Company resulting solely and directly from a change in rate structure from license plate rates to another rate structure for recovering the embedded costs of transmission facilities used to provide Network Integration Transmission Service; (d) any increase in transmission charges resulting from charges associated with regional transmission expansion costs that are chargeable under the PJM Tariff to the Dominion zone, and which are not included in the Company's transmission revenue requirement; or (e) any increase in transmission costs to the Company or any revenues resulting from the FERC's orders in Docket Nos. ER04-829 and ER05-6 et al. imposing the Seam Elimination Cost Adjustments (SECAs);

PJM Order Condition (1)e states that:

Dominion shall allocate sufficient FTRs, ARRs, or other revenues toward its fuel costs to offset any congestion charges or other fuel-related costs resulting from Dominion joining PJM and sought to be recovered from Dominion's North Carolina retail ratepayers through the operation of G.S. 62-133.2;

PJM Order Condition (1)f states that:

Neither PJM, Dominion nor any affiliate shall assert in any proceeding in any forum that federal law, including, but not limited to, the Public Utility Holding Company Act of 1935 (PUHCA) or the Federal Power Act (FPA), preempts the Commission from exercising such authority as it may otherwise have (or would have were Dominion not a member of PJM) under

[25] FERC is the Federal Energy Regulatory Commission.

North Carolina law to set the rates, terms and conditions of retail electric service to Dominion's North Carolina retail ratepayers and that Dominion shall bear the full risks of any such preemption;

PJM Order Condition (2) states that:

> Dominion and PJM shall, consistent with, and to the extent not altered by, the above regulatory conditions and this Order, comply with the terms of the Joint Offer of Settlement [JOS] filed December 16, 2004.

The JOS had two signatories: PJM and Dominion. Some of its provisions ended as of December 31, 2014, but others did not. Some of the provisions were reiterated by the Commission in the PJM Order and were put in place "until further Order of the Commission." In its July 8, 2016 Supplemental Filing, Dominion reiterated that it is seeking relief from compliance with the JOS.

PJM Order Condition (3) states that:

> Dominion and PJM shall, consistent with the above additional regulatory conditions, comply with the terms of the Settlement Agreement with Progress filed December 16, 2004. Dominion and PJM shall, with regard to all of the signatories thereof, honor , and discharge Dominion's obligations pursuant to, the various VACAR[26] and other regional agreements referenced in the Settlement Agreement, including, but not limited to the VACAR Reserve Sharing Agreement, as Dominion would have been so obligated to do prior to Dominion's integration with PJM. In fulfilling this condition, Dominion and PJM shall continue to follow the practices and operating procedures around these agreements that have been customarily observed by the participants but do not necessarily exist in written form.

The "Progress Settlement Agreement" among DNCP, PJM and Progress Energy Carolinas, Inc. (now Duke Energy Progress) contained six very detailed provisions intended to ensure that commitments and practices that DNCP had made or instituted in order to assure reliability in the VACAR region during emergencies would survive, with specific tasks being agreed to by PJM.

PJM Order Condition (4) states that Dominion would continue to comply with all regulatory conditions and codes of conduct previously imposed by the Commission. The PJM Order further stated that "the conditions imposed by the Commission shall remain in effect for a period of not less than ten (10) years from the date of Dominion's integration into PJM and continuing thereafter indefinitely and until further Order of the Commission."

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[26] VACAR is a sub-region of the SERC Reliability Corporation (SERC), and covers the states of Virginia, North Carolina and South Carolina. In the Southeast, SERC implements and enforces the reliability standards that are developed by NERC and approved by FERC.

In his direct testimony, DNCP witness Hupp noted that the Commission imposed the PJM conditions for a period of not less than 10 years and indefinitely until further Commission order, and that more than 10 years have passed since DNCP integrated with PJM. Witness Hupp testified that to the best of his knowledge, since integration into PJM, DNCP has complied with all of the PJM Order conditions and has held customers harmless via the operational and financial benefits provided by DNCP's membership in PJM. Witness Hupp described the operational benefits as more reliable and efficient operations, improved outage and reserve planning, and participation in the PJM stakeholder process.

Witness Hupp also testified that in Docket No. E-22, Sub 428, the Commission ordered DNCP to perform, beginning with its next fuel case, a study of the fuel costs that would have been incurred had DNCP not joined PJM (the PJM Integration Study). Witness Hupp stated that in each of the ten PJM Integration Studies conducted from 2006 through 2015, DNCP demonstrated significant savings to customers as a result of DNCP's PJM membership. Particularly since 2009 when the Company began using the PJM Integration Study in its current form, witness Hupp testified that the studies demonstrate substantial financial savings that outweigh the costs, including administrative costs, associated with DNCP's integration into PJM.[27]

Witness Hupp testified that based on the consistently demonstrated benefits of DNCP's PJM integration since 2005, the Company should be relieved from further compliance with the PJM conditions. He explained that the Company's integration into PJM is now complete, and concerns about new and unknown aspects of joining a regional transmission organization no longer apply. Witness Hupp noted that in the Company's 2014 fuel factor proceeding the Commission recognized that due to the passage of time since the integration with PJM, one or more of the PJM conditions could be ripe for review.

Witness Hupp testified that several of the PJM conditions prohibit the Company from recovering through rates certain costs associated with PJM participation. These costs include congestion and other fuel-related costs which Condition 1(e) required DNCP to offset with Financial Transmission Rights (FTRs), Auction Revenue Rights (ARRs), and other revenues. Witness Hupp noted that in the Company's 2014 fuel case, due to this condition, the Commission disallowed recovery of $1.5 million of congestion costs that the Company believed were prudently incurred. Condition 1(d) similarly prohibits DNCP from recovering administrative costs associated with PJM membership. Witness Hupp clarified that DNCP is not asking to pass such costs on to customers without a prudence review. Instead, the Company seeks the opportunity to recover these prudently incurred costs.

In its July 8, 2016 Supplemental Filing the Company provided more specific representations regarding its ongoing commitments for its continued retail electric service in North Carolina, notwithstanding its request for relief from the PJM Order conditions.

[27] DNCP is not currently required to perform the PJM Integration Study pursuant to the Commission's final order in the Company's 2015 fuel clause adjustment proceeding, Docket No. E-22, Sub 526.

The Company also presented a detailed cost-benefit analysis of the impact of the PJM integration on customers, supported by the supplemental direct testimonies of witnesses Hupp and Bailey.

DNCP clarified in the Supplemental Filing that, while the Company is seeking relief from all of the PJM Order conditions, certain obligations to which it is subject as a North Carolina regulated electric utility exist separate and apart from the PJM conditions and will continue to apply to the Company even if the Commission grants the Company's request for relief. Furthermore, the Company is subject to some regulatory conditions that were imposed by the Commission before DNCP joined PJM, and DNCP stated that it would remain subject to all such conditions.[28] The Company clarified that it would continue to comply with the following obligations:

> (1) DNCP's North Carolina retail customers will continue to be entitled to, and receive, cost-based rates for generation, transmission, and distribution (including any ancillary services) determined pursuant to North Carolina law notwithstanding DNCP's integration into PJM or decision to participate in any capacity or energy market administered by PJM.
>
> (2) DNCP will continue to serve its native load customers in North Carolina with the lowest-cost power it can generate or purchase from other sources in order to meet its native load requirements before making power available for off-system sales.
>
> (3) DNCP will continue to take all reasonable and prudent actions necessary to continue to provide its North Carolina retail customers with superior bundled retail electric service and customer service.
>
> (4) Neither DNCP nor any of its affiliates will assert in any proceeding in any forum that federal law, including but not limited to the Public Utility Holding Company Act of 1935 (PUHCA) or the Federal Power Act (FPA), preempts the Commission from exercising such authority as it may otherwise have (or would have were DNCP not a member of PJM) under North Carolina law to set the rates, terms, and conditions of retail electric service to DNCP's retail ratepayers, and DNCP shall bear the full risks of any such preemption.
>
> (5) DNCP will continue to comply with all regulatory conditions and codes of conduct previously imposed by the Commission.

[28] Those previously imposed regulatory conditions include Regulatory Conditions 30-42 to the Commission's October 18, 1999 Order Approving Code of Conduct and Amending Conditions of Merger issued in Docket No. E-22, Sub 380, which prohibited the Company from asserting federal preemption of the Commission's authority in any forum.

The Company also provided information in the Supplemental Filing regarding how the other conditions contained in the PJM Order either are moot or are otherwise covered by other agreements.

With regard to Condition (1) of the PJM Order, DNCP clarified that it is requesting relief from the portion of this Condition that requires that the costs of generation and transmission, among other things, included in DNCP's North Carolina retail rates be no greater than the lesser of such costs determined on the basis of historical, embedded costs, calculated consistent with the Commission's currently existing rate base, rate-of-return ratemaking practices and procedures, or the marginal costs of generation and transmission supplied into or purchased from PJM. The Company reiterated that it would continue to set rates for service based on its cost of service.

With regard to Condition (2) of the PJM Order, which requires DNCP and PJM to comply with the terms of the Joint Offer of Settlement, DNCP clarified that it is seeking relief from this condition. The Company stated that Paragraphs (1) through (6) of the Joint Offer of Settlement either were subsumed within broader obligations imposed by the conditions contained in the PJM Order or were subject to sunset dates that have since passed.

The Company also explained that Paragraphs (7)(a) through (7)(c) of the Joint Offer of Settlement outline curtailment protocols that have been superseded by current PJM and North American Electric Reliability Corporation (NERC) requirements as provided for in the PJM tariff and NERC reliability standards.

With regard to Paragraph (7)(d) of the Joint Offer of Settlement, which states that "nothing in this approval of this application shall alter the Commission's authority over the application of curtailment practices to Company's retail customers," DNCP stated that any current authority held by the Commission regarding the application of curtailment practices would remain in effect even if the Commission grants the Company's request for relief from these conditions.

DNCP explained that the obligations imposed by Paragraph (8) of the Joint Offer of Settlement, which required a stakeholder process related to locational marginal pricing and settlements, have been fulfilled by PJM's actions to implement Residual Metered Load market rules, which took effect June 1, 2015.

DNCP stated that Paragraphs (9) through (11) of the Joint Offer of Settlement address obligations to which it is already subject as a North Carolina regulated electric utility and that will continue to apply to the Company even if the Commission grants the Company's request for relief from the PJM Order conditions. These obligations include the need to seek permission to build electric generation and transmission facilities in North Carolina, the requirement to comply with the Commission's integrated resource planning requirements, the requirement to promptly address reliability and service quality issues, and the requirement to follow the laws, rules and policies of the Commission for the provision of retail electric service. The Company clarified that it is not seeking authorization to cease compliance with any of these obligations.

DNCP stated that the Commission's jurisdiction over any subsequent transfer of the Company's North Carolina transmission facilities exists independent of Paragraph (12), making that provision unnecessary.

Paragraph (13) provided for the confidentiality of the discussions that resulted in the Joint Offer of Settlement. DNCP stated that due to the passage of time and the application of other agreements, this provision is no longer relevant. Even so, DNCP will continue to treat as confidential any information provided as such.

Paragraph (14) asserted that changes to the Joint Offer of Settlement required the Company's agreement. DNCP stated that, to the extent this requirement is deemed to apply, the Company was submitting a written signed request for relief from the Joint Offer of Settlement.

Paragraph (15) addressed the possibility that the Commission might not accept the Joint Offer of Settlement. DNCP stated that because the Commission had issued its Notice of Decision on March 30, 2005, in Docket No. E-22, Sub 418, Paragraph (15) is moot.

With regard to Condition (3) of the PJM Order, which pertains to the Settlement Agreement between DNCP and DEP that was filed on December 16, 2004, in Docket No. E-22, Sub 418 (Progress Settlement), DNCP clarified that it is seeking relief from this condition. DNCP represented that it had conferred with counsel for DEP, and that DEP and DNCP agreed that the obligations and commitments contained in the VACAR Reserve Sharing Agreement and other regional agreements referenced in the Progress Settlement are being met pursuant to the current, updated versions of those agreements, as well as other agreements entered into subsequent to the Company's PJM integration, including the Joint Operating Agreement between PJM and DEP most recently filed with FERC in Docket No. ER15-29-000. DEP and DNCP therefore agreed that a Commission Order relieving DNCP of the obligation to comply with the terms of the Progress Settlement would not adversely impact the legal effectiveness of the terms and conditions applicable to DNCP, PJM, and DEP under these agreements.

In his supplemental testimony, witness Hupp presented the results of the Company's detailed analysis of the full costs and benefits of PJM integration over the period of 2006-2015. He explained that the analysis compares actual cost and benefit data from the 10-year period during which DNCP has been a PJM member to a theoretical environment in which DNCP did not join PJM and instead continued to operate as a separate control area. He stated that the Company analyzed several categories of cost and benefit data from 2006 through 2015, including market energy, FTRs, ancillary services, administrative costs, market capacity, and transmission costs. Witness Hupp provided detailed descriptions of how the Company derived the data for each category, and testified that the results of the analysis for all of the categories except administrative costs showed there was a substantial economic benefit to the Company's North Carolina retail customers from its integration into PJM. He noted that the Company did not attempt to speculate as to the comparable administrative costs that the Company would have incurred as a separate control area, and that the administrative costs associated with PJM membership were significantly more than offset by the economic benefits realized in each of the other analyzed categories.

In his supplemental testimony, DNCP witness Bailey testified in support of witness Hupp's discussion of the transmission-related costs and benefits associated with DNCP's PJM participation over the 2006-2015 period. Witness Bailey stated that the cost-benefit analysis assumes that the same transmission projects would be developed whether or not the Company was a member of PJM or a separate control area. In support of this assumption, witness Bailey explained that projects developed pursuant to the PJM Regional Transmission Expansion Plan (RTEP) process include "baseline," "supplemental," and "network" projects. He stated that the RTEP process identifies baseline projects for development that are needed to comply with, for example, mandatory NERC reliability standards and, as such, those projects would likely have been developed whether or not the Company was a PJM member. He also stated that the vast majority of supplemental projects, which DNCP develops in response to specific customer needs are based on the need to support load growth or additions that also would be present whether or not DNCP was in PJM. Finally, witness Bailey testified that since network projects are developed in response to specific generation, merchant transmission, or long-term firm transmission service requests and are paid for by the requesting interconnection entity, those projects were not reflected in the cost/benefit analysis.

In his direct testimony, Public Staff witness McLawhorn summarized the PJM Order conditions and the Company's direct and supplemental filings. He stated that based on the Public Staff's review of DNCP's cost benefit analysis and its consultation with an outside consultant, Christensen Associates Energy Consulting, the Public Staff believes that DNCP's study methodology was generally reasonable and that the available data are verifiable. Witness McLawhorn noted that while the Public Staff believes that DNCP's quantification of the net benefits associated with its PJM membership may be overstated, the Public Staff agrees that there has been a net economic benefit to DNCP ratepayers from 2006-2015 as a result of the integration. He also stated that, based on the most current projections of natural gas prices, capacity prices, and other PJM-related costs, the Public Staff expects the net benefits of DNCP's membership in PJM to continue, driven mainly by fuel cost savings. Witness McLawhorn concluded that, based on its review of the cost/benefit analysis and the clarifications made in the Supplemental Filing, the Public Staff believes that the benefits of DNCP's integration into PJM exceed the costs, and that these benefits can be expected to continue under current forecasts, even with inclusion of the costs previously excluded by Conditions 1(d) and (e). He noted further that, as to Conditions 1(a)-(c), (f), 2, 3 and 4, the Public Staff believes that the clarifications made by the Company in the Supplemental Filing are appropriate and sufficient to support relief from those conditions, with the exception of the filing requirements in Paragraphs 5 and 6 of the JOS. These two paragraphs require the filing of information related to congestion costs and transmission constraints, revenues associated with FTRs and ARRs, a summary of DNCP's monthly capacity and energy transactions with the PJM markets, and locational marginal pricing information.

Witness McLawhorn recommended that, to the extent that DNCP does not already file the information required by these Paragraphs in its annual fuel rider application, DNCP should be required to file that information in the same or substantially similar detail as the filing made by the Company on August 31, 2016, with its annual fuel proceeding. Otherwise, he stated that the Public Staff does not oppose the Company's request for relief from the PJM conditions as clarified by DNCP in the Supplemental Filing. Witness McLawhorn recommended that the Commission's order granting the Company's request for relief from these conditions specifically address the subject matter of Conditions 1(a)-(c), (f), 2, 3, and 4 and incorporate the clarifications made by the Company in its Supplemental Filing. Finally, witness McLawhorn testified that the Public Staff believes that the Commission will be able to protect North Carolina ratepayers should DNCP's participation in PJM prove not to be beneficial in the future. He stated that the Commission has full authority to ensure that DNCP complies with the representations and commitments made in the Supplemental Filing with respect to obligations that exist separate and apart from the PJM conditions, including regulatory conditions previously imposed by the Commission. With regard to the additional PJM costs that DNCP may seek to recover from ratepayers upon being relieved of the PJM conditions, that is, costs excluded from rates under Conditions 1(d) and (e), such costs would be recoverable only when they are shown to have been reasonable and prudently incurred.

In his rebuttal testimony, witness Hupp testified that the Company does not oppose witness McLawhorn's recommendation that the Company continue to file the information required by Paragraph 5 of the JOS in conjunction with its annual fuel cases. He also stated the Company's understanding that the independent market monitor for PJM will continue to file the information required by Paragraph 6 of the JOS. [29]

Section XIV of the Stipulation provides that the Company is relieved from further compliance with the PJM Order conditions, subject to: (1) the Company's clarifications regarding its ongoing commitments as contained in its July 8, 2016 Supplemental Filing in this docket; (2) the Company's continuing to file with its annual fuel clause adjustment filing the information required by Paragraph 5 of the JOS; and (3) the IMM for PJM continuing to annually file the information required by Paragraph 6 of the JOS. Section XIV also provides that the Company will comply with the representations and commitments made in the Supplemental Filing with respect to obligations that exist separate and apart from the PJM Conditions.

[29] The Commission notes that on November 16, 2016, counsel for Monitoring Analytics, LLC (PJM's independent market monitor) filed a letter in this docket stating that "should the Commission accept the Stipulation, Monitoring Analytics, LLC, acting as the [IMM] for PJM will continue to annually file ... the information specified in Paragraph 6 of the Joint Offer of Settlement ... filed in ... 2004."

No other party submitted evidence regarding the Company's request for relief from the PJM conditions.

At the hearing, witness Hupp testified in response to Commission questions that the Company would not object to the Commission directing DNCP to continue to comply with the obligations it agreed to continue to meet in the Supplemental Filing notwithstanding the Company's request for relief from the conditions related to those obligations. On redirect, witness Hupp agreed that the Company took the approach of requesting relief from all the conditions while committing to continue compliance with its independent and ongoing obligations as a North Carolina retail electric utility as that would allow for a "clean slate" going forward. Witness Hupp noted that the forward-looking evaluation of costs and benefits that the Public Staff conducted indicated that the benefits and savings of PJM integration would continue. He stated on redirect that it is no longer valid to compare the circumstances before the Company joined PJM to those after integration, given the length of time that DNCP has been a PJM member and the benefits it has shown from integration. He also confirmed that regardless of whether it is a PJM member, the Company always seeks to provide service at least cost and to economically dispatch its fleet.

Witness Hupp confirmed in response to Commission questioning that certain decisions that the Company makes with regard to operating within PJM, such as whether to bid into the markets or buy market energy, would be subject to prudence review. He agreed that, with regard to other costs that PJM controls, such as administrative costs, the Company participates in various committees at PJM and could protest any inappropriate costs, and that either DNCP or the IMM could complain to FERC if there are disagreements with PJM. He also confirmed that in the Company's 2014 fuel case, even though DNCP's fuel costs as a PJM member were lower than they would have been had DNCP operated as a separate control area, FTR and ARR revenues were used to offset congestion costs that the Company incurred in order to gain the benefits of PJM participation. He confirmed that over $1 million from those FTR and ARR revenues were offset against those costs, which he viewed as one way in which the continuance of the conditions would be unfair.

On redirect, witness Hupp confirmed that the cost-benefit analysis included in the Company's Supplemental Filing was conducted at the request of the Public Staff, and that it built on the PJM Integration Studies that DNCP conducted as part of its fuel cases from 2006-2015. He agreed that in addition to the market energy costs addressed in those fuel case studies, the cost-benefit analysis also evaluated FTRs, capacity, transmission costs, ancillary services, and administrative costs, and that the overall result showed a substantial financial benefit to the North Carolina retail jurisdiction from DNCP joining PJM. He clarified that the reporting requirements that witness McLawhorn has asked to be continued were part of the JOS with PJM, and that DNCP is requesting relief from all of the conditions in the other settlement agreement in the PJM case, which was with Progress Energy Carolinas, Inc., now Duke Energy Progress, LLC (DEP). He testified that the Company conferred with DEP on all of the conditions contained in that settlement agreement and that DNCP and DEP agreed that all of them are being addressed now under other agreements. Finally, witness Hupp testified on redirect that the Company has for the past 11 years not been allowed to recover significant costs of doing business due to the PJM Order conditions. He testified that the Company is now seeking to be allowed the chance to recover all of the costs of providing reliable and least cost service to its customers.

In response to Commission questions, witness McLawhorn testified to his recommendation that the Company continue to file the information required by Paragraphs 5 and 6 of the JOS. He agreed that it would be sufficient for the PJM IMM to resume filing the Paragraph 6 information as it had done previously.

The post-hearing exhibit filed by DNCP and the Public Staff shows that, as stated in witness Hupp's testimony, all of the conditions imposed by the PJM Order are now either no longer applicable or are being met under subsequent and currently effective agreements, with the exception of the ongoing reporting requirements agreed to in the Stipulation. The exhibit also noted PJM's confirmation that all of the conditions are now covered elsewhere or no longer apply.

The Commission finds the testimony of Public Staff witness McLawhorn persuasive. He concluded that DNCP's cost-benefit analysis methodology and assumptions were reasonable, and that even if the quantification was overstated, there has been a net economic benefit to DNCP's customers from PJM membership. Witness McLawhorn also stated, based on the most current projections of natural gas prices, capacity prices and other PJM-related costs, the Public Staff expects the net economic benefits of DNCP's membership in PJM to continue. The Commission agrees with witness McLawhorn that it has full authority to ensure DNCP's compliance with the representations the Company made in the Supplemental Filing, and that any additional PJM-related costs that the Company seeks to recover will only be recoverable if the Company shows them to have been reasonable and prudently incurred.

The evidence presented in this case demonstrates that DNCP's integration into PJM has benefited its customers, and that those benefits can be expected to continue even if the Commission relieves the Company from compliance with most of the PJM Order conditions. Going forward and as clarified at the hearing and in witness McLawhorn's testimony, DNCP will be required to show that costs incurred with respect to PJM membership are reasonable and were prudently incurred, just as with any other costs for which the Company seeks recovery. The Commission fully expects Dominion to use its voice in various PJM committees at PJM to protest any inappropriate PJM-related costs, to complain to FERC if there are irreconcilable disagreements with PJM adversely affecting its North Carolina ratepayers, and to communicate any such concerns to the Commission and the Public Staff. Therefore, the Commission concludes that based on all of the evidence presented, it is appropriate to grant the Company's request for relief from most, but not all, of the conditions imposed by the PJM order.

The Company shall continue to comply, or shall compel PJM's independent market monitor to comply, with the reporting obligations established in Paragraphs 5 and 6 of the JOS and as provided at Section XIV of the Stipulation. The Company shall also continue to meet the five commitments that it agreed to be subject to as a North Carolina regulated retail electric utility and as it stated in its Supplemental Filing. Finally, the Company shall make a compliance filing in this docket within 30 days of the issuance of this Order, which filing shall consist of a comprehensive Code of Conduct that shall include all of the ongoing obligations and commitments to which the Company agrees to be bound, consistent with its representations, the Stipulation, and this Order. This filing shall include conditions that predate the PJM Order. The Public Staff is requested to review the filing and provide comments to the Commission within 30 days.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 51

The evidence supporting this finding of fact and these conclusions is contained in the testimony and exhibits of the Company and Public Staff, and in the Stipulation.

As fully discussed above, the provisions of the Stipulation are the product of the give-and-take of settlement negotiations among DNCP, the Public Staff, and CIGFUR I. Comparing the Stipulation to DNCP's Application, and considering the direct testimony of the Public Staff witnesses, the Commission observes that there are provisions of the Stipulation that are more important to DNCP, and, likewise, there are provisions that are more important to the Public Staff. For example, DNCP is intent on obtaining deferral of the post-in-service costs of the Brunswick County and Warren County CC generating facilities, as well as deferral of the Chesapeake Energy Center impairment and closure costs. Indeed, the depth of DNCP's commitment to obtain deferral of the Warren County CC costs is evident from the fact that DNCP filed for reconsideration of the Commission's March 29, 2016 Order denying deferral of those costs. On the other hand, the Public Staff is intent on limiting DNCP's Marketing Percentage for the fuel cost of purchase power to 78%, substantially lower than the 100% sought by DNCP. Further, the Public Staff is focused on resisting any increase in the basic facilities charge component of DNCP's rates. Nonetheless, working from different starting points and different perspectives, the Stipulating Parties were able to find common ground and achieve a balanced settlement.

In addition, the Commission notes that the Stipulation provides customer benefits that are beyond what the Commission has the authority to require of DNCP. These include the $400,000 shareholder contribution by DNCP to the EnergyShare program that provides energy assistance to customers in need in the Company’s North Carolina service territory; DNCP's withdrawal of its request for recovery of the site separation costs associated with the proposed North Anna 3 nuclear plant; and DNCP’s accelerated refund of its fuel cost over-recovery through Rider A1.

The result is that the Stipulation strikes a fair balance between the interests of DNCP and its customers. As discussed above, the Commission has fully evaluated the provisions of the Stipulation and concludes, in the exercise of its independent judgment, that the provisions of the Stipulation are just and reasonable to all parties to this proceeding in light of the evidence presented, and serve the public interest. The provisions of the Stipulation strike the appropriate balance between the interests of DNCP’s customers in receiving safe, adequate, and reliable electric service at the lowest possible rates, and the interests of DNCP in maintaining the Company's financial strength at a level that enables the Company to attract sufficient capital. As a result, the Commission concludes that the provisions of the Stipulation are just and reasonable under the requirements of the Public Utilities Act. Therefore, the Commission approves the Stipulation in its entirety. In addition, the Commission finds and concludes that the Stipulation is entitled to substantial weight and consideration in the Commission's decision in this docket.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 52

The evidence for this finding of fact and these conclusions is contained in the Application, the testimony and exhibits of the DNCP witnesses and the Public Staff witnesses, the Stipulation, and the record as a whole.

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

For example, DNCP witness Curtis testified that during the last three years the Company invested $2.3 billion to bring online a total of 2,700 MW of new generation. Witness Curtis stated that this new generation is cleaner and more highly-efficient combined cycle generating capacity that has the potential to create substantial fuel savings due to very favorable current natural gas prices. Witness Curtis cited in particular the operation of the Warren County CC since December 2014, and stated that this facility has created system-wide fuel savings of approximately $65.9 million when compared to wholesale market power purchases. In addition, he stated that the Brunswick County CC is expected to produce similar fuel savings and operational benefits.

Witness Curtis further testified that DNCP has spent approximately $170 million on transmission improvements in North Carolina during the last three years. He stated that these improvements support improved reliability of the transmission system and local economic growth. He also testified that the Company plans to invest an additional $243 million in transmission improvements in North Carolina from 2016 through 2019.

In addition, witness Curtis testified that DNCP has invested over $102 million in its distribution system in North Carolina during the last three years. He stated that these investments balance the need for reliable service with prudent spending.

Witness Curtis also testified regarding the impact of current and proposed environmental regulations on the Company's operations. He stated that during the last decade electric utilities have been required to address compliance with a suite of new environmental standards adopted by the United States Environmental Protection Agency (EPA). He testified that compliance with these standards has had a direct impact on DNCP's operation of its coal-fired generating plants, citing as an example the EPA's Mercury Air Toxics Standards Rule (MATS). Witness Curtis stated that the cost of complying with MATS was a primary driver in the Company's decision to retire over 900 MW of coal-fired generating capacity. He also discussed the impact of the EPA's CCR Final Rule.

Moreover, witness Curtis testified that DNCP has invested approximately $296 million since 2014 to increase security at its transmission substations and at other critical points in its infrastructure. Further, he stated that the Company plans to invest an additional $260 million for such purposes between 2016 and 2018.

In addition, Company witness Mitchell described the 2013 conversion of the Altavista, Hopewell and Southampton Power Stations from coal-burning facilities to renewable biomass-fueled generation facilities.

These are representative examples of the capital investments that have been made and are planned to be made by DNCP in order to continue providing safe, reliable and efficient electric service to its customers. Based on all of the evidence, the Commission finds and concludes that the rates established herein strike the appropriate balance between the interests of DNCP's customers in receiving safe, reliable and efficient electric service at the lowest possible rates, and the interests of DNCP in maintaining the Company's financial strength at a level that enables the Company to attract sufficient capital. As a result, the Commission concludes that the rates established by this Order are just and reasonable under the requirements of G.S. 62-30, et seq.

IT IS, THEREFORE, ORDERED as follows:

1. That the Stipulation filed by DNCP, the Public Staff, and CIGFUR I is hereby approved in its entirety.

2. That DNCP shall be allowed to increase its rates and charges effective for service rendered on and after January 1, 2017, so as to produce an increase in gross annual revenue for its North Carolina retail operations of $25,790,000, consisting of an increase of $34,732,000 in base non-fuel revenues, and a decrease of $8,942,000 in base fuel revenues.

3. That the proper aggregate base fuel factor for this proceeding is 2.070¢/kWh, excluding regulatory fee, and 2.073 ¢/kWh, including regulatory fee. The Company shall replace the voltage-differentiated base fuel factors approved in Docket No. E-22, Sub 479, with the following voltage-differentiated base fuel factors, including gross receipts tax, effective January 1, 2017:

Customer Class	Base Fuel Factor
Residential	2.095 ¢/kWh
SGS & PA	2.093 ¢/kWh
LGS	2.079 ¢/kWh
NS	2.014 ¢/kWh
6VP	2.043 ¢/kWh
Outdoor Lighting	2.095 ¢/kWh
Traffic	2.095 ¢/kWh

4. That the jurisdictional and class cost allocation, rate designs, rate schedules, and service regulations proposed by the Company, except as specifically addressed in this Order, are approved and shall be implemented. As discussed in this Order, DNCP shall continue to offer Nucor service pursuant to the terms and conditions of Schedule NS and the Nucor agreement approved on March 29, 2016 in Docket No. E-22, Sub 517, as modified to reflect the authorized change in non-fuel base revenues.

5. That DNCP shall implement Rider EDIT as shown on Settlement Exhibit IV via a rate that is calculated using the sales shown in Column 1 of Company Rebuttal Exhibit PBH-1, Schedule 11. Prior to the tenth month from the effective date of the Year 2 rider, the Company shall provide an analysis to the Public Staff to evaluate if the total rider credit will be provided at the end of Year 2. If there is a deviation between the total rider credit and the projected credit provided to customers, the Company and the Public Staff shall work together to develop an adjustment to the Rider EDIT to minimize the deviation over the remaining months of Rider EDIT being in effect.

6. That as soon as practicable after the date of this Order, DNCP shall file for Commission approval five copies of rate schedules designed to comply with the rate design approved in this Order accompanied by calculations showing the revenues that will be produced by the rates for each schedule. This shall include a schedule comparing the revenue produced by the filed schedules during the test period with the revenue that will be produced under the rate schedules to be approved herein and a schedule illustrating the rates of return by class based on the revenues produced by the rates for each schedule.[30]

[30] If necessary, the Commission will address in a subsequent order any refund due based on the any differences in the rates approved in this Order and the Company's temporary rates implemented on November 1, 2016.

7. That as soon as practicable after the issuance of the last Commission Order in DNCP's four pending rate-related proceedings, which are this proceeding, the Sub 534 fuel charge adjustment proceeding, the Sub 535 renewable energy and energy efficiency portfolio standard (REPS) cost recovery proceeding, and the Sub 536 demand-side management proceeding, DNCP shall file a consolidated proposed customer notice addressing the rate changes associated with the non-fuel base and base fuel rate changes approved in this proceeding (Sub 532), the Fuel Rider B in the Sub 534 proceeding, the Rider RP and RPE rate changes in Sub 535, and the demand-side management Rider C and Rider CE rate changes in Sub 536. Such notice shall include the effect of each rate-related proceeding on a residential customer using 1,000 kWh and the combined effect of all four rate-related proceedings on a residential customer using 1,000 kWh. Upon approval by the Commission, DNCP shall notify its North Carolina retail customers of the foregoing rate adjustments by including the approved notice as a bill insert with customer bills rendered during the next regular scheduled billing cycle.

8. That the Company may use levelization accounting for nuclear refueling costs as described in this Order**.**

9. That the Company shall continue to annually file a cost of service study with the Commission using the Summer/Winter Peak and Average methodology.

10. That the Company shall comply with Commission Rule R8-27(a)(2) regarding future establishments of regulatory assets and liabilities as provided at Section XI.D of the Stipulation.

11. That the Company shall file with the Commission, on the same date it files its quarterly ES-1 report, a report detailing: (1) the CCR deferrals recorded in the reporting period; and (2) regulatory accounting entries pursuant to the August 6, 2004 Order in Docket No. E-22, Sub 420, with regard to any costs other than nuclear decommissioning costs or CCR costs recorded in the reporting period.

12. That the Company shall notify the Commission when the Yorktown Power Station closure occurs and provide estimates of its undepreciated value at the time of closure and the level of costs to be incurred for closure.

13. That with the exception of the commitments in DNCP's July 8, 2016 Supplemental Filing, the Stipulation, and Commission-imposed conditions that predate DNCP's integration into PJM, DNCP is hereby relieved of the PJM Order conditions. Within 30 days of this Order the Company shall file in this docket a compliance filing which shall consist of a comprehensive Code of Conduct that includes all of these ongoing conditions and obligations, including those that predate the PJM Order. The Public Staff is requested to review the Code of Conduct and provide comments within 30 days of DNCP's compliance filing.

14. That the Company shall continue to file the information referenced in Paragraph 5 of the Joint Offer of Settlement dated December 16, 2004, between DNCP and PJM with its annual fuel clause adjustment filing.

15. That prior to DNCP filing its next general rate case, the Company shall work with Utilities International to determine whether it can produce an application that would enable an intervenor or the Public Staff to perform certain UI Model functionalities in Excel, generally including manipulating allocation factors to prepare their own cost of service studies in future rate case proceedings.

16. That the Company shall develop and file for Commission approval a new LED schedule for North Carolina jurisdictional customers within one year of this Order.

17. That the Company shall make a one-time shareholder contribution to its EnergyShare program of $400,000, over and above its usual contribution, for the benefit of its North Carolina customers by January 31, 2017.

18. That if DNCP continues to recover any deferred costs for a longer period of time than the amortization period approved by the Commission for those deferred costs, DNCP shall not record those deferred costs in its general revenue accounts, but, rather, shall continue to record all amounts recovered as deferred costs in the specific regulatory asset account established for such deferred costs until the Company's next general rate case.

19. That the Company shall file with the Commission a proposed pilot or experimental Real Time Pricing rate offering no later than July 1, 2017.

20. That DNCP shall provide a written summary of its TOU rates, and its RTP rates, when developed, to each residential customer presently being served and to be served in the future by a smart meter.

21. That the agreement between DNCP and NCSEA regarding DNCP's TOU rate offerings shall be, and is hereby, approved.

22. That the Company shall file an Average and Excess cost allocation methodology in its next North Carolina general rate case, in addition to the cost allocation methodology proposed by the Company.

ISSUED BY ORDER OF THE COMMISSION.

This the 22nd of December, 2016.

NORTH CAROLINA UTILITIES COMMISSION

Linnetta Threatt

Linnetta Threatt, Acting Deputy Clerk