NORTH CAROLINA UTILITIES COMMISSION

103rd REPORT
JAN. 1, 2013
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ONE-HUNDRED THIRD REPORT

OF THE

NORTH CAROLINA

UTILITIES COMMISSION

ORDERS AND DECISIONS

ISSUED FROM
JANUARY 1, 2013 THROUGH DECEMBER 31, 2013

ONE-HUNDRED THIRD REPORT
of the
NORTH CAROLINA UTILITIES COMMISSION

ORDERS AND DECISIONS

Issued from

January 1, 2013, through December 31, 2013

Edward S. Finley, Jr., Chairman

*William T. Culpepper, III, Commissioner

Bryan E. Beatty, Commissioner

Susan W. Rabon, Commissioner

ToNola D. Brown-Bland, Commissioner

*Lucy T. Allen, Commissioner

*Don M. Bailey, Commissioner

*Jerry C. Dockham, Commissioner

*James G. Patterson, Commissioner

North Carolina Utilities Commission
Office of the Chief Clerk
Gail L. Mount
4325 Mail Service Center
Raleigh, North Carolina 27699-4325

The Statistical and Analytical Report of the North Carolina Utilities Commission is printed separately from the volume of Orders and Decisions and will be available from the Office of the Chief Clerk of the North Carolina Utilities Commission upon order.

*William T. Culpepper, III, retired June 30, 2013
*Lucy T. Allen, retired June 30, 2013
*Don M. Bailey, appointed June 24, 2013
*Jerry C. Dockham, appointed July 1, 2013
*James G. Patterson, appointed July 1, 2013

LETTER OF TRANSMITTAL

December 31, 2013

The Governor of North Carolina
Raleigh, North Carolina

Sir:

Pursuant to the provisions of Section 62-17(b) of the General Statutes of North Carolina, providing for the annual publication of the final decisions of the Utilities Commission on and after January 1, 2013, we hereby present for your consideration the report of the Commission's significant decisions for the 12-month period beginning January 1, 2013, and ending December 31, 2013.

The additional report provided under G.S. 62-17(a), comprising the statistical and analytical report of the Commission, is printed separately from this volume and will be transmitted immediately upon completion of printing.

Respectfully submitted,

NORTH CAROLINA UTILITIES COMMISSION

Edward S. Finley, Jr., Chairman

Bryan E. Beatty, Commissioner

Susan W. Rabon, Commissioner

ToNola D. Brown-Bland, Commissioner

Don M. Bailey, Commissioner

Jerry C. Dockham, Commissioner

James G. Patterson, Commissioner

Gail L. Mount, Chief Clerk

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DOCKET NO. E-100, SUB 137

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of 2012 Biennial Integrated Resource Plans and Related 2012 REPS Compliance Plans	)))	ORDER APPROVING INTEGRATED RESOURCE PLANS AND REPS COMPLIANCE PLANS

HEARD: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on February 11, 2013

Courtroom 5310, Mecklenburg County Courthouse, 832 E. Fourth Street, Charlotte, North Carolina on February 28, 2013

BEFORE: Commissioner Bryan E. Beatty, Presiding; Chairman Edward S. Finley, Jr., and Commissioners William T. Culpepper, III, Susan W. Rabon, ToNola D. Brown-Bland, and Lucy T. Allen

APPEARANCES:

For Virginia Electric and Power Company, d/b/a Dominion North Carolina Power:

Andrea Kells and E. Brett Breitschwerdt, McGuireWoods LLP, 434 Fayetteville Street, Suite 2600, Raleigh, North Carolina 27601

For Duke Energy Progress, Inc., and Duke Energy Carolinas, LLC:

Lawrence B. Somers, Deputy General Counsel, Duke Energy Corporation,
P.O. Box 1551, Raleigh, North Carolina

Charles A. Castle, Associate General Counsel, Duke Energy Corporation, P. O. Box 1321 (DEC 45A), Charlotte, North Carolina 28201

For North Carolina Electric Membership Corporation and GreenCo Solutions, Inc.:

Richard M. Feathers, Vice President and Associate General Counsel, 3400 Sumner Boulevard, P. O. Box 27306, Raleigh, North Carolina 27611-7306

For North Carolina Waste Awareness & Reduction Network, Blue Ridge Environmental Defense League, and Greenpeace:

John D. Runkle, 2121 Damascus Church Road, Chapel Hill, North Carolina 27516

For Mid-Atlantic Renewable Energy Coalition:

Bruce Burcat, P.O. Box 385, Camden, Delaware 19934

For the North Carolina Sustainable Energy Association:

Michael D. Youth, P. O. Box 6465, Raleigh, North Carolina 27628

For the Using and Consuming Public:

Timothy R. Dodge, Lucy E. Edmondson, and Robert S. Gillam, Staff Attorneys, Public Staff-North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: Integrated Resource Planning (IRP) is intended to identify those electric resource options that can be obtained at least cost to the utility and its ratepayers consistent with the provision of adequate, reliable electric service. IRP considers demand-side alternatives, including conservation, efficiency, and load management, as well as supply-side alternatives in the selection of resource options. Commission Rule R8-60 defines an overall framework within which the IRP process takes place in North Carolina. Analysis of the long-range need for future electric generating capacity pursuant to G.S. 62-110.1 is included in the Rule as a part of the IRP process.

General Statute (G.S.) 62-110.1(c) requires the Commission to “develop, publicize, and keep current an analysis of the long-range needs” for electricity in this State. The Commission's analysis should include: (1) its estimate of the probable future growth of the use of electricity; (2) the probable needed generating reserves; (3) the extent, size, mix, and general location of generating plants; and (4) arrangements for pooling power to the extent not regulated by the Federal Energy Regulatory Commission (FERC). Further, G.S. 62-110.1 requires the Commission to consider this analysis in acting upon any petition for the issuance of a certificate for public convenience and necessity for construction of a generating facility. In addition, G.S. 62-110.1 requires the Commission to submit annually to the Governor and to the appropriate committees of the General Assembly a report of its: (1) analysis and plan; (2) progress to date in carrying out such plan; and (3) program for the ensuing year in connection with such plan. G.S. 62-15(d) requires the Public Staff to assist the Commission in making its analysis and plan pursuant to G.S. 62-110.1.

G.S. 62-2(a)(3a) declares it a policy of the State to:

> assure that resources necessary to meet future growth through the provision of adequate, reliable utility service include use of the entire spectrum of demand-side options, including but not limited to conservation, load management and efficiency programs, as additional sources of energy supply and/or energy demand reductions. To that end, to require energy planning and fixing of rates in a manner to result in the least cost mix of generation and demand-reduction measures which is achievable, including consideration of appropriate rewards to utilities for efficiency and conservation which decrease utility bills . . . .

Session Law (S.L.) 2007-397 (Senate Bill 3), signed into law on August 20, 2007, amended G.S. 62-2(a) to add subsection (a)(10) that provides that it is the policy of North Carolina "to promote the development of renewable energy and energy efficiency through the implementation of a Renewable Energy and Energy Efficiency Portfolio Standard (REPS)" that will: (1) diversify the resources used to reliably meet the energy needs of North Carolina's consumers, (2) provide greater energy security through the use of indigenous energy resources available in North Carolina, (3) encourage private investment in renewable energy and energy efficiency, and (4) provide improved air quality and other benefits to the citizens of North Carolina. To that end, Senate Bill 3 further provides that "[e]ach electric power supplier to which G.S. 62-110.1 applies shall include an assessment of demand-side management and energy efficiency in its resource plans submitted to the Commission and shall submit cost-effective demand-side management and energy efficiency options that require incentives to the Commission for approval."[1]

Senate Bill 3 also defines demand-side management (DSM) as "activities, programs, or initiatives undertaken by an electric power supplier or its customers to shift the timing of electric use from peak to nonpeak demand periods" and defines an energy efficiency (EE) measure as "an equipment, physical or program change implemented after 1 January 2007 that results in less energy being used to perform the same function."[2] EE measures do not include DSM.

To meet the requirements of G.S. 62-110.1 and G.S. 62-2(a)(3a), the Commission conducts an annual investigation into the electric utilities' IRPs. Commission Rule R8-60 requires that each utility, to the extent that it is responsible for procurement of any or all of its individual power supply resources (collectively, the utilities),[3] furnish the Commission with a biennial report in even-numbered years that contains the specific information set out in that Rule. In odd-numbered years, each of the electric utilities must file an annual report updating its most recently filed biennial report.

Further, Commission Rule R8-67(b) requires any electric power supplier subject to Rule R8-60 to file a REPS compliance plan as part of each biennial and annual report. In addition, each biennial and annual report should (1) be accompanied by a short-term action plan that discusses those specific actions currently being taken by the utility to implement the activities chosen as appropriate per the applicable biennial and annual reports and (2) incorporate information concerning the construction of transmission lines pursuant to Commission Rule R8-62(p).

Within 150 days after the filing of each utility's biennial report and within 60 days after the filing of each utility's annual report, the Public Staff or any other intervenor may file its own

[1] G.S. 62-133.9(c).

[2] G.S. 62-133.8(a)(2) and (4).

[3] During the 2013 Session, the General Assembly enacted S.L. 2013-187 (House Bill 223), which exempted the EMCs from the requirements of G.S. 62-110.1(c) and G.S. 62-42, effective July 1, 2013. As a result, EMCs are no longer subject to the requirements of Rule R8-60 and are no longer required to submit IRPs to the Commission for review.

plan or an evaluation of, or comments on, the utilities' biennial and annual reports. Furthermore, the Public Staff or any other intervenor may identify any issue that it believes should be the subject of an evidentiary hearing. The Commission must schedule one or more hearings to receive public testimony.

2012 BIENNIAL REPORTS

This Order addresses the 2012 biennial reports (2012 IRPs) filed in Docket No. E-100, Sub 137, by Duke Energy Progress, Inc. (DEP); Duke Energy Carolinas, LLC (DEC); and Dominion North Carolina Power (DNCP) (collectively, the investor-owned utilities or IOUs), and North Carolina Electric Membership Corporation (NCEMC),[1] Rutherford EMC (Rutherford), Piedmont EMC (Piedmont), Haywood EMC (Haywood), and EnergyUnited EMC (EnergyUnited) (collectively, the electric membership corporations or EMCs).[2] In addition, this Order addresses the REPS compliance plans filed by the lOUs, GreenCo,[3] Halifax EMC (Halifax), and EnergyUnited.

The following parties intervened in this docket: Blue Ridge Environmental Defense League (BREDL); Carolina Industrial Group for Fair Utility Rates I, II, and III (CIGFUR); Carolina Utility Customers Association, Inc. (CUCA); Greenpeace; Mid-Atlantic Renewable Energy Coalition (MAREC); North Carolina Sustainable Energy Association (NCSEA); North Carolina Waste Awareness and Reduction Network (NC WARN); Sierra Club; and Southern Alliance for Clean Energy (SACE). The Public Staff’s intervention is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

PROCEDURAL HISTORY

On August 8, 2012, Rutherford filed a letter indicating that its load would be included in DEC’s IRP filing for reporting purposes, and its REPS compliance plan would be reflected in DEC’s REPS compliance plan. On August 30, 2012, EnergyUnited filed its 2012 IRP and 2012 REPS compliance plan. On August 31, DNCP filed its 2012 IRP and 2012 REPS compliance

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[1] NCEMC indicated that it provides wholesale power to 25 of the 26 EMCs in North Carolina and is the full requirements power supplier for 20 of the cooperatives. NCEMC's 2012 IRP is filed on behalf of these 20 members. NCEMC provides partial requirements capacity and energy entitlements to 5 EMCs: Blue Ridge EMC, Rutherford EMC, Piedmont EMC, Haywood EMC, and EnergyUnited (collectively, the independent EMCs). The 26th EMC, French Broad EMC, is not a member of NCEMC and is not required to file an individual IRP, as it has entered into a full requirements contract with DEP.

[2] Blue Ridge EMC contracts with DEC as its full requirements and REPS compliance service provider. Blue Ridge EMC, therefore, is not required to file an IRP.

[3] GreenCo filed a consolidated 2012 REPS compliance plan on behalf of Albemarle EMC, Brunswick EMC, Cape Hatteras EMC, Carteret-Craven EMC, Central EMC, Edgecombe-Martin County EMC, Four County EMC, French Broad EMC, Haywood, Jones-Onslow EMC, Lumbee River EMC, Pee Dee EMC, Piedmont, Pitt & Greene EMC, Randolph EMC, Roanoke EMC, South River EMC, Surry-Yadkin EMC, Tideland EMC, Tri-County EMC, Union EMC, and Wake EMC.

plan, and Rutherford filed its 2012 IRP. On September 4, 2012, DEC[1] and DEP filed their 2012 IRPs and 2012 REPS compliance plans, NCEMC filed its 2012 IRP, and GreenCo and Halifax filed their 2012 REPS compliance plans. On September 11, 2012, Piedmont filed its 2012 IRP, and on September 13, 2012, Haywood filed its 2012 IRP. On November 11, 2012, DNCP filed an amendment to its 2012 IRP.

On October 8, 2012, the Commission issued an Order scheduling a public hearing on the 2012 IRPs and the 2012 REPS compliance plans for February 11, 2013, in Raleigh.

On January 10, 2013, the Public Staff filed a motion requesting that the deadline for the filing of comments on the 2012 IRPs and REPS compliance plans be extended to February 5, 2013, which the Commission granted by Order dated January 15, 2013. This Order also extended the deadline for reply comments to February 19, 2013.

On February 4, 2013, BREDL, Greenpeace, and NC WARN (NC WARN, et al.) submitted their joint comments on the 2012 IRPs. On February 5, 2013, comments on the 2012 IRPs were submitted by the Public Staff, MAREC, NCSEA, and jointly by SACE and the Sierra Club. On February 7, 2013, MAERC filed an amended version of its initial comments.

On February 15, 2013, DEC and DEP filed a motion for extension of time to file reply comments until March 5, 2013, which the Commission granted by Order issued on February 18, 2013.

On March 5, 2013, reply comments were filed by Halifax, Rutherford, SACE, DNCP, EnergyUnited, NCEMC, and jointly by DEC and DEP.

On July 15, 2013, the Commission issued an Order which, among other things, called for the filings of proposed orders and briefs in this docket on or before August 26, 2013.

On July 22, 2013, NCSEA filed a partial proposed order limited to the issue of access to electricity consumption data that it had raised in its initial comments.

On August 21, 2013, the Public Staff filed a motion requesting an extension of time to September 9, 2013, for the filing of briefs and proposed orders, which was granted by the Commission on August 22, 2013.

On September 6, 2013, NC WARN, et al., filed its brief. On September 9, 2013, SACE and the Sierra Club filed a joint brief, MAREC filed a brief, and the Public Staff, DNCP, and DEC and DEP jointly filed proposed orders.

NC WARN et al.'s Motion for Additional Public Hearings

On January 9, 2013, NC WARN, et al., filed a motion requesting that the Commission hold additional public hearings in Charlotte and Asheville. NC WARN, et al., stated, among

[1] DEC's REPS compliance plan included the REPS compliance plans for Rutherford and Blue Ridge EMC.

other things, that there was considerable public interest in the IRPs in Charlotte and Asheville, that members of those communities felt it would be a hardship to attend the public hearing in Raleigh, and that a single public hearing would not provide adequate time to hear from all interested persons.

On January 24, 2013, the Commission issued an Order allowing responses to the motion for additional hearings. On January 31, 2013, SACE and the Sierra Club filed a joint response supporting the motion for additional hearings. On February 1, 2013, DEC and DEP filed a joint response stating that there was no need to hold additional IRP public hearings, since several avenues existed for members of the public to express their views about the IRPs, including the public hearing in Raleigh, letters, petitions, and electronic mail. They also stated that NC WARN, et al.'s position on the construction and operation of generating facilities is well documented and additional public hearings would result in needless repetition of the same talking points, and that if the Commission decided to grant NC WARN, et al.'s motion, it should schedule one hearing to be held in a location that is central to both Charlotte and Asheville, such as Hickory.

On February 5 and 6, 2013, the Commission granted NC WARN, et al.'s motion in part by scheduling one public hearing to be held in Charlotte, North Carolina on February 28, 2013.

NC WARN, et al.'s Motion for an Evidentiary Hearing

In their initial joint comments filed on February 4, 2013, NC WARN, et al. requested that the Commission hold an evidentiary hearing on whether the IRPs submitted by DEC and DEP are in the best interest of ratepayers and provide "least cost" electricity. In their initial joint comments, SACE and the Sierra Club indicated their support for an evidentiary hearing and proposed issues on which the Commission might wish to receive pre-filed testimony and conduct a hearing. In their March 5, 2013, reply comments, the IOUs indicated that they did not view NC WARN, et al.'s request for an evidentiary hearing as presenting compelling issues or reasoning in support of such a hearing, and that the request for an evidentiary hearing should be denied.[1]

On May 3, 2013, the Commission issued an Order Requiring Verified Responses in which it noted that during the public hearings, as well as in statements of position regarding this proceeding that were mailed or emailed to the Commission, many citizens questioned whether the IRPs filed by DEC and DEP appropriately reflect the expected growth in demand for electricity, the ability to meet that demand with EE and renewable energy resources, and other aspects of the IRPs. As a result of these concerns, as well as information from other proceedings and forums, the Commission found good cause to require DEC and DEP to provide verified answers on or before Monday, June 10, 2013, to 19 questions listed on Attachment A to its Order. The topics covered by the questions included EE, DSM, renewable energy, tiered electric rates, public benefit loan funding, solar generation, future EE potential, full compliance with REPS requirements, population growth projections, projected annual retail load growth, generation reserve margins, coal plant emissions and climate change initiatives.

[1] DEC and DEP reply comments at 11; DNCP reply comments at 13.

On May 13, 2013, NC WARN, et al., filed a response to the Commission's Order stating, among other things, that the questions included in the Order helped to shed light on several issues not covered in the IRPs. In addition, NC WARN, et al. proposed that two additional questions be added to the list of Commission questions. The proposed questions asked whether DEC and DEP had conducted a study of the potential for using combined heat and power (CHP). Further, NC WARN, et al. stated that it continued to urge the Commission to hold an evidentiary hearing in this docket.

On June 10, 2013, DEC and DEP filed a combined verified response to the Commission's 19 questions.

On July 15, 2013, the Commission issued an Order denying NC WARN, et al.'s motion for an evidentiary hearing. In its Order, the Commission concluded that the substantive issues raised by ratepayers in their testimony and written comments and by the intervenors in their initial comments have been addressed by DEC and DEP in their respective reply comments and in their responses to the Commission's Order Requiring Verified Responses. In addition, the Commission concluded that the record contains sufficient detail to allow the Commission to decide all contested issues without the necessity of a further evidentiary hearing, and that there is not good cause to require DEC and DEP to answer the additional questions proposed by NC WARN, et al.

NCSEA's Motion for Disclosure

On February 5, 2013, NCSEA filed a motion for disclosure requesting that the Commission require DEC and DEP to make public certain information in their REPS compliance plans that was filed under seal with the Commission as confidential trade secret information. In addition, NCSEA requested that the Commission order DEC, DEP, and DNCP to annually review their REPS compliance plans from four years earlier and make public all information that was previously redacted from those plans, or file an explanation of why the information should remain confidential. On February 7, 2013, the Commission issued an Order requesting that interested parties file comments and reply comments in response to NCSEA's motion. On March 7, 2013, initial comments were filed jointly by DEC and DEP. On March 8, 2013, initial comments were filed jointly by SACE and the Sierra Club, and individually by DNCP. On March 25, 2013, NCSEA filed reply comments and on April 1, 2013, DNCP filed reply comments.

On June 3, 2013, the Commission issued an Order granting NCSEA's motion in part by (1) ordering DEP to amend its 2012 REPS compliance plan by filing as public information the specific REPS contract information disclosed in Exhibit 1 of DEP's 2008 and 2010 REPS compliance plans, to the extent that this information has not changed and continues to be a part of DEP's 2012 REPS compliance plan, and further, to include this specific contract information in its subsequent REPS compliance plans under the same guidelines; (2) ordering DEC to amend its 2012 REPS compliance plan by disclosing the information redacted in its 2008 REPS compliance plan, subject to prohibitions in the contracts and after redacting the names of counterparties; (3) ordering DEP, DEC, and DNCP to annually review their REPS compliance plans from four years earlier and disclose any redacted information that is no longer a trade secret; and (4) reaffirming the guidelines stated in the Commission's Order Concerning Confidentiality of Report Filings in Docket No. P-100, Sub 133, issued on October 21, 1997, which required parties to submit at the time of filing information under seal a detailed and cogent statement of the reasons the information is a trade secret pursuant to G.S. 132-1, et seq. On July 1, 2013, DEC filed revised 2008 and 2012 REPS compliance plans.

NCSEA Request for Rulemaking

In its initial comments, NCSEA requested that the Commission find that there is an inadequacy of access to customer information, that this inadequacy impedes the greater utilization of DSM/EE, and that the Commission should open a rulemaking docket to expand access to customer data, both to the customers of the electric power suppliers and third parties, such as smart grid technology companies, at the meter level and the aggregate level. NCSEA stated that the rule changes could potentially enable:

(1) Academic and governmental institutions to conduct research, the results of which will help educate society about energy usage;
(2) Businesses to develop and roll out innovative energy usage products and services; and
(3) Customers to exercise greater control over their energy usage and its economic, environmental, and social impacts.[1]

NCSEA stated that Commission Rule R8-51 may be antiquated and not accurately reflect, for example, the availability of more granular data than monthly usage or customer interest in accessing their electricity consumption data via the internet. NCSEA pointed out that the National Association of Regulatory Utility Commissioners (NARUC) and the American Council for an Energy Efficient Economy (ACEEE) have called for promulgation of rules that contemplate such issues, and numerous states have adopted rules that increase the availability of this information while maintaining the privacy of customer information in the absence of disclosure authorization.[2]

In its reply comments, DNCP disputed the need for a rulemaking proceeding and noted that expansion of access to customer information in the manner suggested by NCSEA should be handled with caution. DNCP noted that customers can be provided greater access than required by Rule R8-51, subject to conformance with DNCP's Code of Conduct, and also can access up to 18 months of historical usage data online or by telephone. In addition, with the customer's written consent, a customer may have his billing information released to a third party, or he may retrieve the information online and provide it to a third party. Further, DNCP stated that it cannot technically comply with NCSEA's suggestion of customer access to a "timely stream" of

[1] NCSEA second comments on March 8, 2013.

[2] NCSEA initial comments at 14, 18, 21, 26, 27.

consumption data, since many of DNCP's North Carolina customers do not have automated metering technology.[1]

In their reply comments, DEC and DEP echoed some of the same concerns raised by DNCP regarding the importance of protecting customer information. DEC and DEP further stated that they have engaged in an ongoing dialogue with NCSEA and the Public Staff about customer data issues and "would not object to a separate rulemaking proceeding to explore customer data access if the Commission deems it advisable."[2]

SACE and the Sierra Club supported initiation of a rulemaking to examine the issue of access to customer data and to make appropriate changes.

In addition to the comments filed by intervenors, various parties, including trade associations, local governments, state agencies, nonprofits, and academic institutions, filed statements of position in support of NCSEA's request that the Commission open a separate rulemaking docket to review and modernize the rules governing access to customer energy usage data.

On August 23, 2013, the Commission issued an Order Requesting Additional Information and Declining to Initiate Rulemaking. In regard to NCSEA's contention that there is a current inadequacy of access to customer information, the Commission declined to make the requested finding on two grounds. First, the Commission noted that in its Order Declining to Adopt Federal Standards, issued on December 18, 2009, in Docket No. E-100, Sub 123, it had declined to adopt the federal standard for smart grid information set forth in Section 111(d)(19)(A)-(C) of the Public Utility Regulatory Policies Act (PURPA) because it found that the utilities were generally providing sufficient access to customer data, which the Commission expected to increase as smart grid technologies are implemented. The Commission also encouraged the utilities to investigate making real time pricing available to all customers and to update time-of-use (TOU) rates. The Commission also noted that in its May 30, 2013, Order Granting General Rate Increase in Docket No. E-2, Sub 1023, it had ordered DEP to complete a study regarding TOU rates and report the results to the Commission. Further, the Commission noted that Commission Rules R8-60 and 60.1 require IOUs to report certain information regarding access to customer information as they implement smart grid technology.

The Commission also disagreed with NCSEA's contention that there is an inadequacy of access to customer information based on Commission Rule R8-51, which the Commission noted is intended to provide customers with full access to all their usage data that is available. The Commission agreed with NCSEA that the availability of electronic and real time data from the IOUs should be clarified and ordered the IOUs to respond to questions regarding access to and availability of electronic and real time data.

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[1] DNCP reply comments at 12.

[2] DEC and DEP reply comments at 12.

As the Commission did not agree with NCSEA that there was an inadequacy of data or lack of customer access to such data, the Commission also declined to find that an inadequacy of data was an impediment to utilization of DSM/EE. Moreover, the Commission did not find that there was a clear linkage between access to customer data and utilization of DSM/EE, as there are a number of other variables that are barriers to greater implementation of EE.

In regard to NCSEA's request that the Commission initiate a rulemaking, the Commission found that such an investigation would be premature as there were insufficient details regarding consumption data that would be available in the future. The Commission indicated that it was inclined to wait until after the filing of the IOUs' smart grid reports on October 1, 2014. The Commission's August 23, 2013 Order also directed DEC, DEP and DNCP to file verified responses to questions listed on Attachment A of the Order by September 23, 2013.

On September 23, 2013, DEC, DEP and DNCP filed verified responses to the Commission's questions.

Public Hearings

Pursuant to G.S. 62-110.1(c), the Commission held two public hearings to take public witness testimony regarding the filed 2012 IRPs and 2012 REPS compliance plans. The first hearing was held on Monday, February 11, 2013, in Raleigh, North Carolina, where 43 public witnesses spoke. The second hearing was held on Thursday, February 28, 2013, in Charlotte, North Carolina, where 70 public witnesses spoke. The witnesses at both hearings discussed a wide range of issues, including the impact of coal-fired electricity generation, the threat of climate change, alternative models for establishing utility rate structures, the reasonableness of utility load growth forecasts, and the opportunities for increased uses of alternative resources such as wind, solar energy, and EE. During the course of this proceeding, the Commission also received over 2,500 letters or emails from customers, generally expressing concern over the utilities' continued reliance on fossil-fueled generation and support for increased use of renewable energy and EE.

Based on the foregoing, the comments of the parties, and the entire record in this proceeding, the Commission makes the following

FINDINGS OF FACT

1. The lOUs' 15-year forecasts of native load requirements and other system capacity or firm energy obligations, supply-side and demand-side resources expected to satisfy those loads, and reserve margins are reasonable and should be approved.

2. The 2012 IRP biennial reports submitted by the IOUs, NCEMC, Piedmont, Rutherford, EnergyUnited and Haywood are reasonable and should be approved.

3 DEC and DEP complied with the Regulatory Conditions related to least-cost integrated resource planning imposed in the Commission's Order Approving Merger Subject to

Regulatory Conditions and Code of Conduct issued June 29, 2012, in Docket Nos. E-2, Sub 998, and E-7, Sub 986 (Merger Order), approving the business combination of Duke Energy Corporation and Progress Energy, Inc., pursuant to G.S. 62-111(a).

4. DEC and DEP should continue to pursue least-cost integrated resource planning and file separate IRPs until otherwise required or allowed to modify this process by Commission order or until a combination of the utilities is approved by the Commission.

5. The IOUs and EMCs included a full discussion of their DSM programs and their use of these resources as required by Rule R8-60(i)(6).

6. The IOUs included in their IRPs a discussion of their market potential studies, including updates, for DSM and EE programs.

7. The IOUs and EMCs provided sufficient details of their investigations of the value of activating their current DSM resources during times of high system load as a means of achieving lower fuel costs by not having to dispatch peaking units with their associated higher fuel costs if it is less expensive to activate DSM resources.

8. The IOUs and EMCs adequately discussed the consumer education programs they currently provide to their customers, or propose to implement within the biennium.

9 The IOUs included in their IRPs a discussion of measures to inform all customers of their system summer peaks so that they might engage in voluntary demand response and peak shaving.

10. The IOUs and EMCs included in their IRPs a discussion regarding the impacts of smart grid deployment on their IRPs.

11. The IOUs provided an adequate assessment of alternative supply-side resources.

12. The IOUs should continue to include a full discussion of alternative supply-side resources in future IRPs to evaluate the potential impacts of these resources on their system.

13. The process used by the IOUs to evaluate resource options and selecting the least cost portfolio is reasonable.

14. DEP and DEC have adequately addressed the issues raised by Sierra Club, SACE, and NC WARN, et al., in this proceeding, including the proper evaluation of EE and DSM resources, least cost portfolio selection, peak demand and energy growth projections, baseload requirements, the cost of new nuclear generation, greenhouse gas emissions, and the potential economic viability of existing scrubbed coal units.

15. The Cliffside Unit 6 Carbon Neutrality Plan filed by DEC is a reasonable path for DEC's compliance with the carbon emission reduction standards of its air quality permit.

16. DEC should continue to provide updates in future IRPs regarding its obligations related to the Cliffside Unit 6 air permit.

17. The 2012 REPS compliance plans submitted by the IOUs, GreenCo, EnergyUnited and Halifax are reasonable and should be approved.

DISCUSSION AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-2

Load Forecasts

In its comments, the Public Staff stated that all of the utilities use accepted econometric and end-use analytical models to forecast their peak and energy needs. The Public Staff noted that, as with any forecasting methodology, there is a degree of uncertainty associated with models that rely, in part, on assumptions that certain historical trends or relationships will continue in the future.

The Public Staff indicated that it reviewed the utilities' 15-year peak and energy forecasts (2013–2027). According to the Public Staff, the compound annual growth rates (CAGRs) for the forecasts of DEC, DEP, and DNCP were within the range of 0.9% to 1.7%, while the CAGRs for NCEMC and the four EMCs that filed IRPs were within the range of 0.9% to 1.9%. The Public Staff also briefly discussed the load reductions achieved by utilities' DSM and EE programs.

DEP

DEP's 15-year forecast predicts that its summer peaks will grow at a CAGR of 0.9%, as compared to 1.6% in its 2011 IRP. Without consideration of the effects of its DSM and EE programs, DEP expects its summer peaks to grow at 1.2%. The average annual growth of its summer peak, which is considered its system peak, is 130 megawatts (MW) for the next 15 years, as compared to 201 MW in the 2011 IRP. DEP predicts that load reductions from its DSM programs will reduce its peak load by approximately 9% in 2027.

DEP's energy sales are predicted to grow at a CAGR of 1.0%, a 0.3% decrease from the projected growth rate in the 2011 IRP. DEP predicts that the megawatt-hour (MWh) reductions from its EE programs will reduce its energy sales by approximately 4% in 2027.

DEP's last annual system peak, 12,770 MW, occurred on Thursday, July 26, 2012, at the hour ending 5:00 p.m. At the time of the peak, DEP activated its EnergyWise Program and its Commercial, Industrial, and Government Demand Response Program, which reduced its peak load by 101 MW and 16 MW, respectively. DEP's 2011 IRP projected that it would have 803 MW available from its DSM programs to reduce its 2012 summer peak. DEP activated 117 MW of DSM in 2012.

DEC

DEC's 15-year forecast predicts that its summer peaks will grow at a CAGR of 1.7%, 0.1% lower than projected in the 2011 IRP. Prior to the implementation of its DSM and

EE programs, DEC expects its summer peaks to grow at 2.0%. The average annual growth of its summer peak, which is considered its system peak, is 321 MW for the next 15 years, as compared to 351 MW from last year's IRP. DEC predicts that load reductions from its DSM programs will reduce its peak load by approximately 10% in 2027.

DEC's energy sales are expected to grow at a CAGR of 1.7%. This growth rate in energy sales is 0.1% less than predicted in the 2011 IRP. DEC predicts that the MWh savings from its EE programs will reduce its energy sales by approximately 5% in 2027.

DEC's last annual system peak, 17,740 MW, occurred on Thursday, July 26, 2012, at the hour ending 5:00 p.m. DEC activated approximately 130 MW of DSM programs to lower the peak. DEC's 2011 IRP projected the availability of 838 MW from its DSM programs to reduce its 2012 summer peak.

DNCP

DNCP's 15-year forecast predicts that its summer peaks will grow at a CAGR of 1.5%, which is a 0.1% increase from the projected growth rate in the 2011 IRP. The average annual growth of its summer peak, which is considered its system peak, is 285 MW for the next 15 years, as compared to 274 MW in the 2011 IRP. DNCP predicts that load reductions from its DSM programs will reduce its 2027 peak load by approximately 2%.

DNCP's energy sales are predicted to grow at an average annual rate of 1.6%. This projected growth rate in energy sales is the same rate as the growth rate in the 2011 IRP. DNCP predicts that the MWh savings from its EE programs will reduce its energy sales by approximately 3% in 2027.

DNCP's last annual system peak, 16,787 MW, occurred on Friday, June 29, 2012, at the hour ending 5:00 p.m. At the time of the summer peak, DNCP called on its Distributed Generation Pilot[1] for a load reduction of 5 MW and its Air Conditioning Cycling Program for a reduction of 53 MW. DNCP's 2011 IRP projected the availability of 45 MW from its DSM programs to reduce its 2012 summer peak.

NCEMC

NCEMC's 15-year forecast predicts that its summer peaks will grow at an average annual rate of 1.4%, a decrease of 0.2% from the predicted growth rate in its 2011 IRP. The average annual growth of its summer peak, which is considered its system peak, is 48 MW.

NCEMC's last annual system peak, 3,121 MW, occurred on Wednesday, January 4, 2012, at the hour ending 7:00 a.m., which is comparable to 2011 when the system peaked at 2,982 MW on January 14 at 8:00 a.m. NCEMC's 2011 IRP projected that 52 MW would be available from its DSM programs.

[1] The Distributed Generation Pilot is a DSM program operating only in Dominion's Virginia jurisdiction.

NCEMC's energy sales are predicted to grow at an average annual rate of 1.4%, a decrease of 0.1% from the growth rate predicted in its 2011 IRP. NCEMC predicts that the MWh savings from its EE programs will reduce its energy sales by approximately 1% in 2027.

EnergyUnited

EnergyUnited's 15-year forecast predicts that its system peak will grow at an average annual rate of 0.9%. Its energy sales are predicted to grow at an average annual rate of 0.9%. The average annual growth of the annual peak is 6 MW over the 15-year forecast. EnergyUnited's annual peak, 573 MW, occurred on Wednesday, January 4, 2012, at the hour ending 8:00 a.m. EnergyUnited activated its DSM programs and reduced the load by 15 MW at the time of the peak.

Haywood

Haywood's 15-year forecast predicts that its system peak will grow at an average annual rate of 1.8%. Its energy sales are predicted to grow at an average annual rate of 1.9%. The average annual growth of the annual peak is 2 MW over the 15-year period. Haywood's annual peak, 73 MW, occurred on Wednesday, January 4, 2012, at the hour ending 8:00 a.m. DEC, which has operational control of Haywood's DSM programs, did not activate the DSM programs at the time of Haywood's winter peak, but it did activate Haywood's DSM programs on two days during July 2012.

Piedmont

Piedmont's 15-year forecast predicts that its system peak will grow at an average annual rate of 1.7%. The average annual growth of its peak is 3 MW over the 15-year period. Piedmont's energy sales are predicted to grow at an average annual rate of 1.7%. Piedmont's annual peak, 125 MW, occurred on Sunday, July 8, 2012, at the hour ending 5:00 p.m. At the time of its peak, Piedmont did not activate its DSM programs.

Rutherford

Rutherford's 15-year forecast predicts that its system peak will grow at an average annual rate of 1.1%. Its energy sales are predicted to grow at an average annual rate of 1.0%. The average annual growth of Rutherford's system peak is 4 MW over the 15-year period. Rutherford's annual peak, 309 MW, occurred on Wednesday, January 4, 2012, at the hour ending 8:00 a.m. DEC, which has operational control of Rutherford's DSM programs, did not activate any of the DSM programs at the time of Rutherford's winter peak, but it did activate Rutherford's DSM programs on four days during June and July 2012.

Summary of Load Forecasts

The following table prepared by the Public Staff summarizes the growth rates for the IOUs' and EMCs' system peak and energy sales forecasts based on their 2012 IRP filings.

2013 - 2027 Growth Rates

(After New EE and DSM)

	Summer Peak	Winter Peak	Energy Sales	Annual MW Growth
DEP	0.9%	1.2%	1.0%	130
DEC	1.7%	1.7%	1.7%	321
DNCP	1.5%	1.5%	1.6%	285
NCEMC	1.4%	1.4%	1.4%	48
EnergyUnited	1.2%	0.9%	0.9%	6
Haywood	1.8%	1.8%	1.9%	2
Piedmont	1.7%	1.7%	1.7%	3
Rutherford	1.1%	1.1%	1.0%	4

In general, the Public Staff concluded that the peak load and energy sales forecasts used by the utilities were reasonable for planning purposes. The Public Staff noted that among the IOUs both DEC's and DEP's forecasts predicted peak loads in excess of actual loads for the past five years and had peak load and energy sales forecast errors that were higher than those of DNCP. The Public Staff recommended that to the extent they have not already done so DEC and DEP should review their equations and other assumptions for possible refinement in order to reduce the possibility of overestimation bias in future load forecasts. In their reply comments, Sierra Club and SACE supported this recommendation. In their initial comments, NC WARN, et al., asserted that DEC and DEP have overestimated the growth in electric demand over the IRP planning horizon in order to justify the construction of new conventional power plants.

In their reply comments, DEC and DEP disputed the claims of NC WARN, et al., indicating that their IRPs present a robust and balanced portfolio over a range of sensitivities. DEC and DEP did not respond directly to NC WARN, et al.'s claim regarding overestimating growth in electric demand, except through incorporation by reference of their reply comments filed in IRP proceedings since 2006.

In its May 3, 2013, Order, the Commission stated that during the public hearings, as well as in comments regarding this proceeding that were mailed or e-mailed to the Commission, many citizens questioned whether the IRPs filed by DEC and DEP appropriately reflect the expected growth in demand for electricity, and directed DEC and DEP to provide verified answers to several questions related to load growth. In Request No. 3, the Commission asked questions regarding difference in projections in electric demand between DEC and DEP's service territory in North Carolina and forecasted electricity sales growth in Indiana and Ohio. In their June 10, 2013, verified responses, DEC and DEP indicated that based on the values used in their most recently filed IRPs in each jurisdiction, sales were projected to grow in all jurisdictions into the future. DEC and DEP further stated that variability in the rates was due to the following reasons:

- DEP, DEC, Duke Energy Ohio and Duke Energy Indiana have different local economies, population make up, retails sales environment, and weather patterns. The load forecasts for each area take into account these differences and they are reflected in the forecast results.
- The load forecasts also include the latest estimates of how sales are expected to respond to changes in key drivers such as economic indicators, population, end-use efficiencies, weather, and retail rates. Based on analysis, customer response to these drivers varies by state.
- Sales for some territories are expected to recover sooner while others are expected to recover later or more gradually, because each service area is in a slightly different state in the economic cycle/recovery as evidenced by trends in unemployment, income, and spending.
- The forecast impacts on load growth associated with incorporating utility sponsored EE programs or complying with a state commission's mandate vary by jurisdiction and the load forecasts show that include those impacts.[1]

In Requests No. 11 and 15, the Commission asked DEC and DEP to provide further justification for the significant volatility in retail sales load growth the utilities have experienced since 1996, including short periods of pronounced growth as well as declines, and to explain how they factored these recent experiences in load growth into their projected load growth in the planning period. The responses from both utilities pointed out the severe recession in 2008-2009 and the large structural decline in textiles having a significant impact on any growth estimates ending in 2011. The utilities stated that they relied on "long-term econometric models by class that relate kWh sales to factors such as weather, price of electricity, real income, as well as service area population projections. The coefficients from the long-term econometric models are then applied to the projections of the weather, economic, and population variables to arrive at the energy forecast."[2] Both utilities indicated that they believe the 1.4% (DEC) and 1.2% (DEP) forecasted load growth provided in their IRPs is reasonable for planning purposes.

In Request No. 12, the Commission asked DEC and DEP to explain a statement by then-President Jim Rogers quoted in the November 29, 2012, edition of the Charlotte Business Journal that the Company's load growth will be lower than projections in the economic models. The Company responded that Mr. Rogers was expressing his personal opinion and that the Company stands by the forecast included in its 2012 IRPs as an accurate forecast for the purpose of preparing the 2012 IRPs. These forecasts are updated annually and new forecasts will be reflected in the 2013 DEC and DEP IRPs."[3]

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[1] DEC and DEP verified responses at 5.

[2] Id. at 14, 16.

[3] Id. at 15-16.

The Commission agrees with the Public Staff that all of the utilities used accepted econometric and end-use analytical models to forecast their peak and energy needs and recognizes the limitations of these models. Nonetheless, the Commission agrees with the Public Staff's recommendation that DEC and DEP continue to review their equations and other assumptions for possible refinement in order to reduce the possibility of overestimation bias in future load forecasts.

Reserve Margin Adequacy

For the planning period 2013 to 2027, the range of summer reserve margins reported by the electric utilities continues to be similar to those used in previous annual reports. For this time period, the reserve margins are:

Utility	Target Reserve Margin	Planned Reserve
DEP	14.5%	15% to 17%
DEC	15.5%	9.2% to 17.9%[1]
DNCP	11%	5.75% to 16.3%

NCEMC indicates that all its purchases include reserves. Future purchases will also include reserves, or NCEMC will acquire reserves independently. The four independent EMCs have active contracts with DEC, DEP, and Southern Company, each requiring the EMCs to maintain reserves commensurate with the supplying electric utility. DEP's IRP indicates that DEP will meet its projected reserve margin targets for the planning period. The Public Staff stated that it considered the planned reserves of the electric power suppliers to be adequate.

DEC's IRP indicates that its reserve margins will drop below its target reserve margin percentages for short periods. DEC points out that significant solar generation is being added to its system. While this generation is not dispatchable, the generation primarily occurs during peak periods. Since the time of the filing of the 2012 IRPs, the interconnection of solar facilities has escalated for all electric suppliers in North Carolina due to the dramatic decrease in the cost of solar photovoltaic (PV) generation, the tax benefits available for renewable generation, and the requirements of the REPS in North Carolina. In addition, DEC's short short-term load growth appears to be lower than originally projected, and usage is lower, possibly due to economic conditions. Based on these factors and the relatively short time periods during which DEC's actual reserve margins fall below its target reserve margins, the Public Staff stated that it found DEC's planned reserves to be adequate. Nevertheless, the Public Staff recommended that DEC include the information required by Commission Rule R8-60(i)(3), which requires a specific explanation for instances when the projected reserve margin varies from the planning reserve margin by plus or minus 3%.

In its reply comments, DEC responded that the instances in which the projected reserve margin exceeded the target by more than 3% were due to "lumpiness" associated with new

[1] DEC utilized a 20-year planning period, hence their planned reserve margins applies for the 2013-2032 period.

generation additions.[1] DEC indicated that the commencement of commercial operation of the Dan River Combined Cycle facility and Cliffside Unit 6 in the fall of 2012 caused an exceedance, but that the accelerated retirement of Buck Units 5-6 and Riverbend Units 4-7 in April 2013 reduced the planning reserve margin to be within 2% of the target reserve margin in 2014. DEC indicated that projected generation additions in 2019, 2022, and 2024 all cause similar exceedances, but that "there is a resource need in these years, that if not met, would require the reserve margin to dip below the target reserve margin."[2] DEC also noted that "while there are substantial increases in solar qualifying facility (QF) interconnection requests since the filing of the 2012 IRP, DEC feels that the solar projections utilized in the IRP adequately account for these additions." DEC stated that it is constantly monitoring the impact of these facilities to the system and will make adjustments to the plan going forward as necessary.[3]

DNCP participates in the PJM market and, through the RPM auction, has obtained a commitment for additional capacity purchases above and beyond the existing identified firm purchases so as to ensure that its reserve margins meet the target of 11% reserves in 2013 and thereafter.

Based on its review of the annual plans, the Public Staff found that the reserves listed are adequate, and recommended that DEC, DEP, and DNCP maintain their proposed reserve margins as filed.

In their initial comments, Sierra Club and SACE stated that DEC's "treatment of demand response raises concerns that DEC may be planning for excessive reserves."[4] Sierra Club and SACE noted that in DEP's reserve margin study, demand response was treated as a resource option, which did not require its own reserve requirements, while in the DEC study, demand response was treated as a resource option requiring backstand reserves. Sierra Club and SACE also noted that:

> For purposes of calculating reserve requirements, system generation resources (and net transactions with other systems) should be compared to net internal demand. As defined by the North American Electric Reliability Corporation (NERC), net internal demand includes unrestricted non-coincident peak adjusted for energy efficiency, diversity, stand-by demand, non-member load, and demand response.[5]

Sierra Club and SACE noted that while DEC has previously stated that some of its programs are not dispatchable or controllable, therefore requiring backstand reserves, data from DEC indicated

[1] DEC and DEP reply comments at 4.

[2] *Id*.

[3] *Id*.

[4] Sierra Club and SACE initial comments at 61.

[5] *Id*. at 63.

that it had been able to activate these programs on numerous occasions and achieve results consistent with, or even in excess of, expected reductions. Sierra Club and SACE noted that DEP's method of accounting for demand response appears to be more consistent with the NERC guidelines, and recommended that, with the exception of its PowerManager (air conditioner) program, DEC should evaluate demand response programs for purposes of calculating reserve requirements as adjustments to net internal demand, similar to the method utilized by DEP.

In its May 3, 2013, Order Requiring Verified Responses, the Commission asked DEC and DEP in Requests No. 13 and 16, respectively, to indicate the date on which and by what amount the highest portion of the utility's reserve margin was utilized to serve its system retail requirements. In their June 10, 2013 replies, DEC indicated for the period 2006 through 2011, its lowest actual reserve margin was 2.2% and occurred on August 9, 2007, while DEP indicated that for the period from 2006 through 2011, the lowest actual reserve margin was 7.1% and occurred on August 6, 2008. DEC and DEP indicated that this actual reserve margin represents the operating reserve margin without impacts of DSM and curtailment riders. DEC and DEP further explained that the planning reserve margin is developed to account for abnormalities in weather, unit availability, and load forecast error, whereas actual reserve margin reflects the actual impacts of these events. Accordingly, the actual reserve margin is expected to be substantially lower than the target planning reserve margin at times.[1]

In Requests No. 14 and 17, the Commission asked DEC and DEP whether either utility had conducted an analysis or study of the potential of using neighboring wholesale resources, such as generation owned by TVA or generation located in PJM, to supply some portion of its reserve margin. In their verified responses, DEC and DEP indicated that their 2012 generation reserve margin studies, both of which were prepared by Astrape Consulting, considered and included the benefit of being interconnected to neighboring utilities such as TVA, Southern, PJM, and SCANA. DEC and DEP both indicated that their reserve margin requirements would have been substantially higher in their studies had these neighboring wholesale resources not been taken into account.[2]

The Commission agrees with the Sierra Club and SACE that in future reserve margin studies DEC should consider demand response programs that it is able to control or dispatch as adjustments to net internal demand, similar to DEP. Nonetheless, the Commission concludes that for the purposes of this proceeding, the reserve margins provided by the electric power suppliers are adequate, and that DEC, DEP, and DNCP should maintain their proposed reserve margins as filed.

DISCUSSION AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3-4

The Regulatory Conditions in the Merger Order set forth commitments made by merging entities and their North Carolina public utility subsidiaries, DEC and PEC (now DEP), as a precondition of approval of the merger. As pointed out in the Public Staff's initial comments, a

[1] DEC and DEP verified responses at 15, 17.

[2] DEC and DEP verified responses at 16, 18.

number of the conditions are relevant to this proceeding, but Regulatory Conditions 3.5 (Least Cost Integrated Resource Planning and Resource Adequacy), 3.6 (Priority of Service), and 4.1 are of particular significance. Regulatory Conditions 3.5 and 3.6 state as follows:

> 3.5 Least Cost Integrated Resource Planning and Resource Adequacy. DEC and PEC shall each retain the obligation to pursue least cost integrated resource planning for their respective Retail Native Load Customers and remain responsible for their own resource adequacy subject to Commission oversight in accordance with North Carolina law. DEC and PEC shall determine the appropriate self-built or purchased power resources to be used to provide future generating capacity and energy to their respective Retail Native Load Customers, including the siting considered appropriate for such resources, on the basis of the benefits and costs of such siting and resources to those Retail Native Load Customers.
>
> 3.6 Priority of Service.
>
> (a) The planning and joint dispatch of DEC's system generation and Purchased Power Resources shall ensure that DEC's Retail Native Load Customers receive the benefits of that generation and those resources, including priority of service, to meet their electricity needs consistent with the JDA [Joint Dispatch Agreement]. DEC shall continue to serve its Retail Native Load Customers with the lowest-cost power it can reasonably generate or obtain as Purchase Power Resources before making power available for sales to customers that are not entitled to the same level of priority as Retail Native Load Customers.
>
> (b) The planning and joint dispatch of PEC's system generation and Purchase Power Resources shall ensure that PEC's Retail Native Load Customers receive the benefits of that generation and those resources, including priority of service, to meet their electricity needs consistent with the JDA. PEC shall continue to serve its Retail Native Load Customers with the lowest-cost power it can reasonably generate or obtain as Purchase Power Resources before making power available for sales to customers that are not entitled to the same level of priority as Retail Native Load Customers.

In addition, Regulatory Condition 4.1 provides that:

> DEC and PEC acknowledge that the Commission's approval of the merger and the transfer of dispatch control from PEC to DEC for purposes of implementing the JDA and any successor document is conditioned upon the JDA or successor document never being interpreted as providing for or requiring: (a) a single integrated electric system, (b) a single BAA [Balancing Authority Area], control area or transmission system, (c) joint planning or joint development of generation or transmission, (d) DEC or PEC to construct generation or transmission facilities for the benefit of the

> other, (e) the transfer of any rights to generation or transmission facilities from DEC or PEC to the other, or (f) any equalization of DEC's and PEC's production costs or rates. If, at any time, DEC, PEC or any other Affiliate learns that any of the foregoing interpretations are being considered, in whatever forum, they shall promptly notify and consult with the Commission and the Public Staff regarding appropriate action.

In its comments, the Public Staff stated that the 2012 IRPs filed by DEC and DEP appear to comply with these requirements. The Commission agrees and concludes that, pursuant to the Regulatory Conditions imposed in the Merger Order, DEC and DEP should continue to pursue least-cost integrated resource planning and file separate IRPs until required or allowed to do otherwise by Commission order or until a combination of the utilities is approved by the Commission.

DISCUSSION AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5-10

In the 2010 and 2011 IRP Orders, the Commission required the IOUs and the EMCs to include in their IRPs, among other things: (1) fuller discussions of their DSM/EE projections and programs, and (2) discussions of any year-to-year annual variance of 10% or more in their projected forecasts of DSM/EE resources. In its comments, the Public Staff indicated that the IOUs and EMCs have generally included these discussions in their IRPs, together with discussions of use of DSM/EE resources during system peak.

Over the planning horizon of the current IRP cycle, DEC projected capacity savings from DSM and EE that are generally 2% to 22% greater[1] than the projections in its 2011 IRP. Its energy savings in the 2012 IRP as compared to those in the 2011 IRP decrease in the early years by a combined 46%, but then increase by over 34%[2] by 2026 and beyond. DEC attributes these changes to the updating of its expectations for program performance, including new DSM and EE programs implemented in 2012 and the expectations identified in its 2012 market potential study. Calculations of projected participation and impacts were largely based on its most current five-year projection, with the five-year projection of impacts remaining constant after the fifth year through the end of the planning horizon. The figures do not include the impact of the grid modernization project discussed below.

Except for 2013, DEP's projected capacity savings from DSM and EE are generally 9% to 19.5% lower than the projections included in the 2011 IRP. However, energy savings increase

[1] Comparison of Line 17 of Table 8A in DEC's 2011 and 2012 IRPs.

[2] Year-by-year comparison of Table 4A in DEC's 2011 and 2012 IRPs. DEC changed the format of Table 4A in its 2012 IRP by adding a column showing the cumulative impacts of its EE programs. However, the Public Staff's calculations are based on a comparison of impacts added in 2011 versus those added in 2012, which do not include the cumulative impacts of the DSM/EE portfolio. The Public Staff believes it is more appropriate to reflect the cumulative impacts of DSM and EE programs as new measures are installed and old measures approach the end of their useful measure lives.

4.2% to 19% over the same planning horizon.[1] DEP also developed its projections of DSM and EE based on the findings of its 2012 market potential study, and attributes the significant changes between the projections in its 2011 IRP and the 2012 IRP to the fact that its new market potential study was conducted by a different consultant who employed a different methodology that assumes a different relationship between MWh energy savings and peak MW demand savings. DEP cites this change in methodology as a driver for its forecasted increase for MWh energy savings and decrease for peak MW demand savings.

DNCP projected significantly lower MW and MWh savings from its portfolio of DSM and EE programs in its 2012 IRP than in its 2011 IRP, a 13% to 31% decrease in its forecast of capacity savings and a 23% to 72% decrease in energy savings over the planning horizon.[2] The larger percent decreases occur early in the planning horizon and appear to be due to regulatory changes in Virginia, as discussed more fully below. DNCP's practice of seeking approval of DSM and EE programs in Virginia before it seeks approval in North Carolina, and the cost caps imposed by the Virginia State Corporation Commission (VSCC), have hampered further development of its North Carolina DSM/EE portfolio. In its comments, the Public Staff stated that it is working with DNCP to determine whether it is cost-effective to offer the Commercial HVAC Upgrade and Commercial Lighting Programs on a North Carolina-only basis, and also to ascertain the proper jurisdictional allocation of the applicable costs. The Commission notes that this program received Commission approval on April 29, 2013, in Docket No. E-22, Sub 486.

In comparison with the capacity savings shown in its 2011 IRP, NCEMC's current projections[3] are generally greater in the earlier years of the planning horizon by as much as 36%, but show declines by as much as 12.7% in later years.[4] In response to a Public Staff data request, NCEMC indicated that the "Load Management and EE" data in Tables 1.3 and 1.4 of its IRP reflect EE program capacity savings at the time of the summer and winter coincident peaks. The Public Staff stated that it believes that these numbers actually reflect the DSM/EE program capacity available as a resource. However, the data also include customer-owned generation. The Public Staff stated in its comments that including both DSM/EE resources and customer-owned generation in Line 2 of Tables 1.3 and 1.4 makes it difficult to isolate only the DSM/EE program capacity. The Public Staff recommended that in future IRPs, NCEMC include separate line items for projected capacity from its DSM/EE portfolio and from customer-owned generation.

NCEMC's projections in its 2012 IRP of energy savings from its DSM/EE portfolio, as compared with the corresponding projections in its 2011 IRP, are 6% to 16% greater in the early

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[1] Changes in capacity and energy savings of DSM and EE programs are based on a comparison of tables on pages E-8 and E-9 of Appendix E of DEP's 2011 IRP and page E-11 of Appendix E of DEP's 2012 IRP.

[2] Calculated based on a comparison of Appendix 2H and 5E of DNCP's 2011 and 2012 IRPs

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[3] For the participating EMCs, NCEMC prepared the 2012 IRP, including load, capacity savings, and energy savings forecasts, while GreenCo prepared the 2012 REPS compliance plan, which included descriptions of the DSM and EE programs incorporated into the forecast tables of NCEMC's 2012 IRP.

[4] Percent changes for capacity are based on a year-to-year comparison of Line 2 in Table 1.3 of the 2011 and 2012 IRPs, which also includes customer-owned generation.

years of the planning horizon, but decrease 3% to 13% in the later years of the planning horizon.[1] NCEMC indicated that these fluctuations result from changes in the EnergyStar Lighting and EnergyStar New Homes programs. The Public Staff indicated that its review of Table 6.2 in NCEMC's 2012 IRP also found decreases in the energy savings of the Commercial Energy Efficiency program, while the other DSM/EE programs maintain consistent or slightly higher savings across the planning horizon. In combination, these changes significantly decrease the energy savings from the portfolio of DSM/EE programs over the planning horizon, in comparison with the 2011 IRP.

The Public Staff's review of the DSM/EE portions of the 2012 IRPs filed by the independent EMCs -- Haywood, Piedmont, Rutherford, and EnergyUnited -- indicates that there is little difference from those filed in previous IRPs.

Each of the electric power suppliers also provided a listing and description of its current and proposed DSM/EE programs. DEC's portfolio of DSM/EE programs in its 2012 IRP includes the programs contained in its 2011 IRP. In addition, DEC added a Tune and Seal measure to its Residential Smart Saver Program, which was approved in Docket No. E-7, Sub 831; My Home Energy Report, which was approved in Docket No. E-7, Sub 1015; Residential Neighbor Low Income Program, which was approved in Docket No. E-7, Sub 1004; Appliance Recycling Program, which was approved in Docket No. E-7, Sub 1005; and the Call Option 200 measure in the Power Share Call Option program, Docket No. E-7, Sub 953. DEC indicated that it was considering proposing the My Energy Manager Program, a residential energy management solution.

DEP's portfolio of DSM/EE programs includes the programs identified in its 2011 IRP. Additional programs in DEP's 2012 IRP are the Residential New Construction Program, approved in Docket No. E-2, Sub 1021, and the Small Business Energy Saver Program, approved in Docket No. E-2, Sub 1022. DEP modified its Residential Lighting Program (renamed Energy Efficiency Lighting) in Docket No. E-2, Sub 950, to expand the measures offered and the availability of the program to non-residential customers. DEP also received approval to modify the Residential Home Energy Improvement Program (Docket No. E-2, Sub 936) and discontinue offering its Residential Home Advantage Program (Docket No. E-2, Sub 928), both due to cost-effectiveness issues. DEP also discontinued its Solar Water Heating Pilot Program, originally approved April 21, 2009, in Docket No. E-2, Sub 937, in 2012 because the program was not cost-effective. In addition to these program changes, DEP also included in its DSM/EE portfolio its Prepay EE program, which is currently approved as a pilot program only in South Carolina.

DNCP's portfolio includes the same DSM and EE programs discussed in the 2011 IRP, with several notable exceptions. Recently, DNCP was denied regulatory approval by the VSCC to expand its Residential Lighting program and implement its new Commercial Refrigeration program. The Commercial Lighting and HVAC programs were also terminated in Virginia and ultimately suspended in North Carolina due to cost-effectiveness issues. However, DNCP gained approval in Virginia for its Commercial Distributed Generation DSM program, Commercial

[1] Percent changes for energy savings are calculated from data in Tables 6.2 of the 2011 and 2012 IRPs.

Duct Testing and Sealing program, and Residential Bundle program.[1] DNCP indicated that it intends to file the Commercial Duct Testing and Sealing and Residential Bundle programs in North Carolina later this year.[2]

DNCP included a list of DSM and EE programs being considered for implementation. The list of programs is largely consistent with the list of proposed programs identified in the 2011 IRP, and includes a resubmittal to the VSCC of the Commercial HVAC and Lighting programs previously denied approval.

The Public Staff stated in its comments that it has worked collaboratively with DEC, DEP, DNCP, and other interested parties to encourage continuation of existing and implementation of new cost-effective DSM/EE programs. The Public Staff commented that the regulatory environment in Virginia continues to challenge the expansion of DNCP's portfolio in North Carolina, and that the cost recovery mechanisms for DEC, DEP, and DNCP will all be reviewed in 2013 and 2014. These subsequent changes to the mechanisms will impact the development of future DSM/EE programs for the IOUs.

The Commission finds that the IOUs and EMCs have adequately discussed their DSM/EE programs in their 2012 IRPs.

Consumer Education Programs and Changes

Commission Rule 8-60(i)(6)(iv) requires each utility to provide a comprehensive list of all consumer education programs it currently provides to its customers, or proposes to implement within the biennium. The utility is also required to provide a list of any educational program it has discontinued since its last biennial report and the reasons for discontinuance.

In its comments, the Public Staff noted that DEC did not specifically address this requirement in its IRP. However, the Public Staff noted that a number of DEC's programs provide customer education. The Public Staff recommended that DEC address this requirement in its reply comments.

In its reply comments, DEC indicated that it has not discontinued any consumer education programs since the last IRP and currently has no plans to implement a new program. DEC provided a list and description of its current consumer education programs, which include Smart Energy Now, Non-Residential Assessments, Duke Energy Online Customer Education Resources, My Home Energy Report, Online Energy Audit, Energy Calculators, Energy Savings Tips, Home Energy House Call, and the K-12 Energy Efficiency Programs.

[1] The Residential Bundle program provides several HVAC-related measures to tune existing HVAC systems or upgrade to more efficient HVAC systems.

[2] DNCP filed these programs on August 20, 2013, in Docket No. E-22, Subs 496 and 500.

DEP's list of consumer education programs and changes to those programs remains consistent with previous IRPs. DEP's main consumer education initiative continues to be its Customized Home Energy Reports.

The lists of consumer education programs discussed by DNCP, NCEMC, Piedmont, EnergyUnited, and Haywood remain largely unchanged from the lists provided in their 2011 IRPs.

The Commission finds that the IOUs and EMCs have adequately addressed their consumer education programs in their 2012 IRPs.

Measures to Inform Customers of Forecasted Peaks and DSM Programs

In its October 30, 2012 Order in Docket No. E-100, Sub 133, which post-dated the filing of the 2012 IRPs, the Commission encouraged electric utilities to take appropriate measures to inform all customers of their system summer peaks so that they might engage in voluntary demand response and peak shaving. In its initial comments in this proceeding, the Public Staff stated that it expected the IOUs and EMCs to include a discussion of their plans to provide customers with this information in their 2013 IRPs.

In their reply comments, DEC and DEP noted that they proactively provide voluntary programs through its Demand Response Programs department to both residential and commercial customers. In addition, they stated that during periods when peak customer usage and/or system conditions forecast the need for additional conservation measures, DEC and DEP have communication plans in place to notify state government agencies, the general public, and company facilities and employees to conserve energy.

DNCP stated in its reply comments that it utilizes several methods to inform its customers of upcoming system peaks in both the summer and winter, including targeted news releases, routine news releases encouraging conservation, promotion of voluntary energy conservation through the internet and social media, and through its media relations staff highlighting energy conservation during peak periods on television and radio interviews.

The Commission finds that the IOUs have included an adequate discussion of their measures to inform all customers of their system summer peaks in their 2012 IRPs.

DSM/EE Market Potential Studies

The 2011 IRP Order required IOUs to include in their IRPs a discussion of their market potential studies, including updates, for DSM and EE programs.

DEC briefly discussed its market potential study for DSM/EE programs completed in late 2011 and indicated that the results were incorporated into Tables 4.A and 4.B of its 2012 IRP. The market potential study indicates that additional potential for DSM and EE in DEC's North Carolina jurisdiction exists, both through new programs and existing programs.

DEP's market potential study is incorporated into its tables of costs and savings identified in Appendix E of its IRP. As in DEC's case, the market potential study suggests that additional potential exists to achieve savings through new DSM/EE programs and expansion of existing programs.

Both DEC's and DEP's market potential studies are based on an economic potential calculated using an avoided cost of $0.07 per kWh. The Public Staff noted in its comments that DEC's consultant (who was also DEP's consultant) stated that its use of this rate was based on its judgment of a reasonable avoided cost considering the hourly shape of EE load impacts and consistency with DEC's avoided cost embedded in DSMore™ and used in its approved DSM/EE cost recovery mechanism. The Public Staff stated that it was concerned that this cost may be too high to properly assess the economic potential of DSM and EE in the Carolinas, particularly based on filings by the IOUs in the current avoided cost proceeding[1] that suggest that underlying avoided costs used to support the avoided cost rates proposed by the IOUs have decreased in the last two years. DEC's and DEP's market potential studies also included an assessment of economic potential using an alternative avoided cost of $0.05/kWh, resulting in an economic potential approximately 30% and 28% less than that calculated using the avoided cost rate of $0.07/kWh, respectively. Even at $0.05/kWh, DEC and DEP continue to see 8,222 and 6,493 million kWh of economic potential, respectively.

In their initial and reply comments, Sierra Club and SACE commented that relying on the PURPA avoided cost rates, as suggested by the Public Staff, would result in an underestimation of the economic potential of DSM and EE programs. Instead, Sierra Club and SACE propose that DEC and DEP utilize the "real levelized system benefit" to estimate the benefits of its DSM/EE programs and measures. Using this method, Sierra Club and SACE calculated the real levelized benefit of EE/DSM of $0.097 per kWh for DEC and $0.113 per kWh for DEP for the planning period (2012-2031). To further support their assertion that avoided costs developed for PURPA purposes underestimate the system benefit of EE, Sierra Club and SACE provided data from three other utilities that have utilized this approach in their 2011 IRP processes, including TVA, PacifiCorp, and Avista Utilities. Based on this analysis, Sierra Club and SACE concluded that "using the PURPA avoided cost to measure the benefit of energy efficiency skews the cost-effective analysis and undervalues the economic potential of the resource."[2] Sierra Club and SACE recommended that DEC and DEP

- Update their potential studies to reflect the real levelized benefit of EE/DSM, which would result in higher economic potential, and should also update their achievable potential estimates for energy efficiency based on this higher estimate.
- Develop a method for estimating the benefit of energy efficiency that is consistent with the system benefit as demonstrated in their resource planning revenue models.
- Using the real levelized benefit of EE/DSM to estimate avoided cost, DEC and PEC should review their current and planned energy efficiency programs, update the

[1] Docket No. E-100, Sub 136 - 2012 Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities.

[2] Sierra Club and SACE reply comments at 2.

> programs' cost-effectiveness calculations, and enhance the programs with additional cost-effective measures to achieve greater customer savings.[1]

In addition, in their initial comments Sierra Club and SACE noted the large number of industrial and large commercial customers that choose to "opt-out" of utility sponsored EE programs and associated riders by implementing alternative DSM and EE measures at their own expense pursuant to G.S. 62-133.9(f) results in a significant lost resource opportunity. Sierra Club and SACE recommended several steps to address the impacts of the opt-out provision, including: (1) DEC and DEP pursuing opportunities to offer programs to these sectors; (2) the Commission initiating a process to verify that opt-out customers are actually implementing their own measures; (3) commercial and industrial customers provide the utilities with better information on their EE efforts, and (4) developing cooperative approaches to increasing the attractiveness of DSM and EE programs to industrial customers.[2]

The Commission notes that the effect of the opt-out provision was raised in DEC's annual DSM/EE cost recovery proceeding in Docket No. E-7, Sub 1031, and in DEC's proposal for approval of a new DSM/EE mechanism in Docket No. E-7, Sub 1032. In the proposed order filed by the Public Staff and DEC on July 25, 2013, in Sub 1031, DEC and the Public Staff proposed that the Commission authorize DEC, the Public Staff, and other interested parties to discuss a potential study or survey of opted-out customers within the collaborative process and to file an update of these discussions as part of its 2014 DSM/EE rider filing and any formal proposal regarding an opt-out study if deemed feasible and appropriate.

In Request Nos. 6, 7, and 8 of its Order Requiring Verified Responses, the Commission asked DEC and DEP to comment on several studies assessing the economic potential of energy efficiency in North Carolina and the Southeast.[3] In their June 10, 2013, reply comments, DEC and DEP generally indicated that the reports did not represent a significant departure from the economic potential analysis utilized by DEC and DEP in their forecasts, and that the following reasons explained some of the different findings amongst the studies: 1) uncertainty regarding customer adoption rates; 2) the time horizons considered; and 3) consideration of potential efficiency gains from building codes, appliance standards, and the natural replacement of end-of-life equipment, all of which are largely captured in the load forecasts of the utilities' IRPs rather than in the EE forecast.

DNCP did not update its 2009 market potential study as part of this proceeding. In its comments, the Public Staff stated that DNCP indicated that it intends to update its market

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[1] Id. At 8.

[2] Sierra Club and SACE initial comments at 36-37.

[3] The three studies were the January 2013 report by the Georgia Institute for Technology, in cooperation with Oak Ridge National Laboratory entitled "Estimating the Energy-Efficiency Potential in the Eastern Interconnection", the 2006 GDS Associated report entitled "A Study of the Feasibility of Energy Efficiency as an Eligible Resource as Part of a Renewable Portfolio Standard for the State of North Carolina," and the March 2010 report by the American Council for an Energy Efficient Economy entitled "North Carolina's Energy Future: Electricity, Transportation, and Water Efficiency."

potential study in 2013 and will incorporate the new market potential study in its 2013 IRP. In its March 5, 2013, reply comments, DNCP confirmed this statement.

Both GreenCo and EnergyUnited provided the Public Staff with copies of their respective updated market potential studies, which were completed in late 2012. Their estimates of future achievable potential are consistent with findings from several other evaluators conducting studies across the country. However, neither market potential study considered DSM in its evaluation. Both market potential studies were based on achieving an overall 40% market penetration, which the Public Staff found to be aggressive goals for EnergyUnited and GreenCo’s individual member EMCs, given the current adoption and participation rates for EE programs for EnergyUnited and some of the EMCs. The recommendations contained in the market potential studies indicate that even with a 20% market penetration level, additional market potential for EE is available by adding new measures to existing programs, adopting new EE programs, and particularly for GreenCo, encouraging member EMCs to implement some of the existing portfolio programs that they do not currently offer. Neither market potential study expressly discusses the avoided costs used to develop the achievable potential. While a brief discussion of national EE resources in both market potential studies suggests that EE is available at $0.03 per lifetime kWh saved, the studies do not address the North Carolina achievable potential of cost effective EE.

Piedmont, Haywood, EnergyUnited, and Rutherford did not include a discussion of a market potential study in their IRPs.

The Commission finds that the IOUs have included an adequate discussion of their market potential studies, including updates, for DSM and EE programs in their 2012 IRPs.

<u>Use of DSM for Possible Fuel Savings</u>

The 2011 IRP Order required each IOU and EMC to investigate the value of using DSM resources during times of high system load, when the marginal cost of fuel is generally at its highest, as a means of achieving lower fuel costs.

DEC discussed its use of DSM resources at various times to respond to both economic and reliability conditions on its system. DEC used some of these occasions to study the potential for fuel cost savings at times of high system costs, focusing on its Power Manager program. DEC’s calculations indicate that potential fuel cost savings from this program were quite small and that the benefit of fuel savings is far outweighed by the avoided capacity costs. Through the use of both participant and non-participant surveys related to DSM usage, DEC concluded that customers could tolerate more frequent, but shorter-duration interruption events without causing participants to leave the DSM program. However, customer participation dropped significantly with longer duration DSM activations. DEC concluded that without careful management, using the DSM program to achieve fuel savings may result in customer attrition.

DEP performed a similar analysis on its Energy Wise Air Conditioning Load Control DSM program. Using actual historical Energy Wise events over the 2009 to 2011 period, DEP estimated that approximately $53,000 in fuel savings was achieved. However, the reduction in participation in Energy Wise would result in a net savings decrease of $49,000. DEP estimated that a net fuel savings of approximately $91,000 to $207,000 could be achieved over the next three years. Like DEC, DEP also evaluated customers' tolerance of more frequent DSM events, using survey and feedback data from current Energy Wise participants. DEP concluded that activating Energy Wise for economic purposes appeared to provide little or no additional value, when balanced with the risks associated with customer acceptance and retention.

DNCP did not expressly address the use of DSM to achieve fuel savings in its IRP. The Public Staff noted that in response to data requests, DNCP indicated that it had not undertaken any formal study of the effects of greater use of DSM during high system load conditions to achieve fuel savings, but acknowledged that it was reasonable to assume that fuel savings result from the use of demand response resources. DNCP included a brief discussion regarding the negative effect on participation in its Residential Air Conditioning Cycling DSM after activations over multiple days during the summer of 2011. As a result, DNCP observed some negative customer feedback, which resulted in customers leaving the program.

NCEMC and the three of the other EMCs indicated that their evaluation of possible fuel savings from the use of DSM resources suggested that at no time during the year were the marginal energy costs greater than the marginal costs associated with activating DSM resources. As a result, NCEMC indicated there were no potential fuel savings to be gained.

In its comments, the Public Staff noted that the potential benefits of using DSM for fuel savings were not as large as it had originally theorized. Based on the findings by DEC and DEP, and DNCP's first-hand experience with customer pushback, the Public Staff recommended that DNCP not be required to conduct a study of potential fuel savings from DSM. In its reply comments, DNCP agreed with the Public Staff's recommendation. The Public Staff stated that it did not believe it was necessary to continue to require discussion of this issue in future IRPs. In their reply comments, Sierra Club and SACE agreed with the Public Staff's recommendation as to current DSM programs, but stated that "utilities should have the opportunity to propose pilot programs or offer new technologies for using DSM to achieve economic fuel savings in the future."[1]

The Commission agrees with the Public Staff that the electric power suppliers should not be required to investigate this issue further. However, electric power suppliers are encouraged to continue to consider potential fuel savings benefits in their evaluations of cost-effective DSM programs in the future.

Smart Grid Impacts and Plans

On April 11, 2012, the Commission issued an Order in Docket No. E-100, Sub 126, amending Commission Rule R8-60 and adopting Rule R8-60.1. Amended Rule R8-60 requires electric power suppliers to file information in their IRPs regarding the impacts of smart grid. Beginning with the 2012 IRP, electric power suppliers were to include specific information regarding their smart grid impacts, including a description of the technologies already installed

[1] Sierra Club and SACE reply comments at 8.

or planned to be installed in the next five years, a comparison of the gross MW and MWh impacts, and impacts to the North Carolina retail jurisdiction and customer classes. Beginning with the 2013 IRP, Rule R8-60.1 requires the electric power suppliers to include a "Smart Grid Technology Plan" with specific information regarding future investments in smart grid technologies.

DEC provided a general description of its "Grid Modernization" program, which involves improvements to its distribution system. DEC estimates that this effort will result in an additional 40 to 135 MW of reduced load over a 10-year period. As a result, DEC included 135 MW of smart grid impacts in the "DSM" column in Table 1.A of its IRP. DEC did not include any discussion of these impacts to the North Carolina retail jurisdiction or customer classes.

DEP provided a discussion of its Distribution System Demand Response (DSDR) program, which involves feeder conditioning, monitoring, and two-way communication capabilities. DEP completed installation of the DSDR program in 2012, and is continuing testing into the 2013 summer season. Ultimately, DEP estimates that DSDR will provide approximately 236 MW of DSM capacity. In its comments, the Public Staff stated that in response to a data request, DEP indicated that once DSDR is fully operational, DEP will incorporate the impacts now associated with its legacy voltage control demand response program and will discontinue reporting voltage control savings separately from DSDR. DEP segregated the impacts of DSDR for the North Carolina retail jurisdiction and customer classes in its IRP.

The Public Staff noted that DNCP did not specifically address its smart grid impacts or discuss plans for smart grid deployment in its 2012 IRP, but included in Chapters 3 and 7 of its 2012 IRP a brief discussion of its advanced metering infrastructure (AMI) and its dynamic pricing pilots that are under way in its Virginia service territory. The Public Staff recommended that DNCP include a discussion of its current smart grid impacts, including impacts by jurisdiction and customer classes, in its reply comments.

In its reply comments, DNCP provided additional details regarding the effectiveness and benefits of installing AMI or smart meters on homes and businesses in several demonstration areas across Virginia. The AMI demonstrations test the effectiveness of its Voltage Conservation program, remotely turning off and on electric service, and Dynamic Pricing Program, both of which are enabled by leveraging AMI as the foundational smart grid technology. DNCP estimated that the Voltage Conservation program saved an estimated 25,773 MWh in demonstration areas across Virginia in 2012, and that approximately 1,317 MWh should be applied to its North Carolina jurisdictional allocation. With regard to the Dynamic Pricing program, DNCP indicated that in response to data requests, it provided the Public Staff with an initial report that included information on customer enrollment and education, but "due to the nature of the rates, a full year of participation is required to analyze energy and demand savings."[1] DNCP stated that an initial measurement and verification (M&V) study will be provided as part of its 2013 annual report to be filed in August 2013, including information on energy and demand savings for the pilot period.

[1] DNCP reply comments at 8.

DNCP also noted in its reply comments that the current filing requirement for Smart Grid Technology Plans, July 1 of each odd-numbered year, does not coincide with the filing date of September 1 of each even-numbered year for IRPs, and that the inconsistency in the timing of these two requirements is not ideal for the utilities to develop and utilize the most current IRP analysis in their development of Smart Grid Technology Plans. DNCP therefore indicated that it would seek to coordinate with other utilities and the Public Staff regarding a delay, either of by motion or rule, of this requirement to October 1, 2014, and every two years thereafter, in order to synchronize the Smart Grid Technology Plan with the IRP filing requirements. In their reply comments, DEC and DEP indicated that they support this recommendation. DNCP moved to amend Rule R8-60.1 on April 10, 2013, in Docket No. E-100, Sub 126, to change the filing date to October 1, 2014. The Commission granted the motion on May 6, 2013.

NCEMC provided a brief discussion of its grid modernization program, including deployment of a new demand response platform known as “Control Data Settlement System” (CDSS), which will support the AMI that several EMCs are implementing. The new CDSS will incorporate two-way communication capabilities and is intended to provide additional opportunities for DSM. NCEMC indicates that the first such program will be its customer-owned generation program. NCEMC also included information regarding the projected impacts of its smart grid initiatives by jurisdiction and customer classes.

Rutherford, Piedmont, Haywood, and EnergyUnited did not include a discussion of smart grid impacts or plans in their respective IRPs. The Public Staff recommended that Rutherford, Piedmont, Haywood, and EnergyUnited include a discussion of its smart grid plans in their reply comments. Rutherford and EnergyUnited filed reply comments addressing their smart grid plans.

The Commission finds that the discussions regarding the impacts of smart grid deployment are adequate for purposes of the 2012 IRPs.

DISCUSSION AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 11-12

Assessment of Alternative Supply-Side Energy Resources

Commission Rule R8-60(i)(7) requires each utility to file its current overall assessment of existing and potential alternative supply-side energy resources, including a descriptive summary of each analysis performed or used by the utility in the assessment. Each utility must also provide general information on any changes to the methods and assumptions used in the assessment since its most recent biennial or annual report.

For the currently operational or potential future alternative supply-side energy resources included in each utility's plan, the utility must provide information on the capacity and energy actually available or projected to be available, as applicable, from the resource. The utility must also provide this information for any actual or potential alternative supply-side energy resources that have been discontinued from its plan since its last biennial report and the reasons for that discontinuance. For alternative supply-side energy resources evaluated but rejected, the utility must provide the following information for each resource considered: a description of the resource; the potential capacity and energy associated with the resource; and the reasons for the rejection of the resource. Each utility provided the information required by Commission Rule R8-60(i)(7).

Based on its planning assumptions, DEC projects that approximately 970 MW of renewable energy resources will be interconnected to its system by 2021, growing to approximately 1,665 MW by 2032. This is a significant increase from DEC's projections in 2011, which estimated approximately 686 MW in 2021 and 884 MW in 2031. Even more striking is the change by renewable energy resource type, which shows an increase in solar by an order of magnitude. In DEC's 2011 IRP, it forecast 51 MW of additional solar capacity by 2021 and 82 MW by 2031. In the current IRP, DEC forecasts 538 MW of new solar capacity by 2021 and 1004 MW by 2032. Further, DEC forecasts a significant decrease in the capacity additions from biomass, reducing its 2011 estimates of 295 MW in 2021 and 391 MW in 2031 to 108 MW in 2021 and 173 MW in 2032. The Public Staff noted that this change in DEC's forecast is consistent with the number of reports of proposed construction and applications for certificates of public convenience and necessity (CPCNs) filed by small power producers, particularly for proposed utility-scale solar PV facilities.

DEP did not provide as detailed a breakdown of its available or projected alternative supply-side energy resources, but did indicate that it forecasts purchasing 208 MW from renewable QFs in 2021 and 210 MW from renewable QFs in 2027. These numbers are an increase from DEP's 2011 IRP, in which it forecast 176 MW in 2021 and 39 MW in 2026.

DNCP projects that it will have 166 MW of renewable capacity in 2013, and that by 2027, it will add 248 MW of onshore wind resources and 34 MW of solar resources, convert three coal-fired facilities (totaling approximately 151 MW) to utilize biomass resources, and purchase additional biomass resources.

NCEMC listed three solar facilities totaling 6.8 MW AC and one landfill gas facility with a capacity of approximately 1 MW as currently operational or potential future alternative supply-side energy resources. It stated that it continues to be engaged in discussions with several developers of additional alternative supply-side resources.

In its comments, the Public Staff commended DEC on its analysis and discussion of alternative supply-side resource additions, as well as its clear delineation of new capacity additions by resource type. The Public Staff also recommended that in their future IRP filings, the other utilities provide additional details and discussion of projected alternative supply-side resources in a manner similar to that utilized by DEC.

In its reply comments, DNCP indicated that it believed its discussion of alternative supply-side resource additions met or exceeded the level of information and analysis provided by DEC, and therefore meets the Public Staff's recommendation.

Over the past few years, the landscape of alternative and distributed resource options has undergone considerable changes, as reflected in part by in the volume and scale of projects seeking CPCNs from the Commission. Greater analysis by the utilities on how these resources will integrate into their system, as well as any costs or benefits associated with the new resources, should be more fully considered in future IRPs. The Commission agrees with the Public Staff that DEC's discussion of recent developments of alternative supply-side resources is a good starting point, and that utilities should continue to provide greater details of these developments in future IRP fillings.

In its amended initial comments filed on February 7, 2013, MAREC indicated that it had concerns about the treatment of renewables, specifically wind, by DEC and DEP in the IRPs, and that several policy reasons supported further consideration of wind energy by the IOUs, including long-term price certainty, in-state investment and economic development, and environmental benefits. MAREC further proposed that DEC and DEP conduct a "new RFP process that would solicit at least 100 MW of new wind energy capacity through a long-term contract(s) for energy and RECs, which would act as a hedge against price volatility and help towards meeting their present and future REPS requirements."[1]

In their initial and reply comments, Sierra Club and SACE agreed that DEC's IRP reflected a more robust evaluation of renewable energy options than DEP's, but stated that both were still flawed in that they only evaluated higher levels of renewable energy resources at the initial screening phase. Sierra Club and SACE recommended that DEC and DEP, similar to DNCP, evaluate one or more "high renewables" portfolios that incorporate renewable energy resources above minimum REPS compliance. Sierra Club and SACE also agreed with MAREC that wind energy offers several benefits, including "lower production costs (and zero fuel costs), a smaller environmental footprint, and a modular nature that matches load growth more closely than larger capacity additions. They also recommended that DEC and DEP "evaluate wind energy not only for REPS compliance, but as a system resource."[2]

The Commission agrees with MAREC that DEP and DEC should continue to assess alternative supply-side resources such as wind energy on an ongoing basis. However, the Commission declines to recommend that the utilities conduct an RFP that is limited to a single resource type unless the specific resource is required for REPS compliance. The Commission does, however, agree that in future IRPs DEC and DEP should more fully consider resource scenarios that envision larger amounts of renewable energy resources similar to DNCP's Renewable Plan in their least-cost integrated resource planning, and to the extent those scenarios are not selected, provide a discussion regarding the reasons.

DISCUSSION AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 13-14

Evaluation of Resource Options

DEC, DEP, and DNCP provided information regarding their analysis and evaluation of resource options as required by Rule R8-60(i)(8). The IOUs indicated that they use accepted production cost simulation models that identify the least cost mix of resources required to meet the future energy and capacity needs in an efficient and reliable manner at the least cost. These

[1] MAREC amended initial comments at 9-10.

[2] Sierra Club and SACE reply comments at 12-13.

models have the ability to perform optimization analyses to select among competing resources that could be added in various combinations to satisfy the utility's future load requirements. They are designed to compare various generation portfolios to determine which has the lowest present value of revenue requirements (PVRR), while maintaining the target reserve margin, and is thus the least-cost portfolio.

The models incorporate forecasts of energy sales and peak load with planning assumptions on the operating characteristics of existing generating units (including, but not limited to net MW output, planned outages, forced outage rates, projected fuel prices, heat rates, start costs, emission costs, and variable operating and maintenance expenses) to calculate the projected dispatch cost of each generating unit. In order to arrive at a least cost plan, the models integrate assumptions regarding planned generation uprates and retirements, planned renewable energy generation, DSM and EE programs, environmental regulations, and the capital costs and operating characteristics for proposed traditional generation and alternative resources.

To consider the uncertainties, the utilities generally develop a base or preferred plan and alternative plans. These plans are analyzed under a variety of scenarios, including changes in projected loads, fuel prices, carbon dioxide (CO_2) emission credit prices, construction costs, and other sensitivities over the planning period, allowing the utility to choose the optimal plan that provides a balanced mix of traditional generation, renewable energy, DSM and EE to meet its baseload, intermediate, and peaking requirements.

In its comments, the Public Staff indicated that it reviewed the forecasts of fuel prices, existing generation characteristics, and the projected capital costs associated with new generation facilities used in the resource optimization models. The Public Staff indicated that based on its investigation, the projected operating and capital costs used in the production models**,** as well as the evaluation of resource options, were reasonable for purposes of this proceeding.

DEC's evaluation indicated that its preferred plan is the portfolio based on full ownership of two nuclear units going into service in 2022 and 2024, supplemented by combustion turbine (CT) and combined cycle (CC) natural gas-fired units. In its comments, the Public Staff noted that the all natural gas portfolio considered by DEC indicated a $10 million lower revenue requirement than the preferred nuclear portfolio. DEC maintained that the portfolios with nuclear remain competitive with the natural gas portfolio because the gas portfolio has more upside risk in fuel costs as identified in its sensitivity analysis. The Public Staff noted that DEC's contention that the nuclear portfolios are competitive is, in part, dependent on the assumption of a carbon constrained economy with the pricing of carbon under various cap and trade proposals or the enactment of clean energy legislation and DEC's desire to lower its carbon footprint. If carbon legislation is not enacted during the planning period, then the natural gas portfolio has a lower revenue requirement that is $3.8 billion lower than the nuclear portfolio and $3.5 billion lower than the regional nuclear portfolio.

In its comments, the Public Staff repeated the concerns regarding DEC's heavy reliance on nuclear generation it had previously raised in Docket No. E-7, Sub 819, and stated that "the benefit of additional nuclear generation from a fuel diversity perspective requires further evaluation. The economics of fuel diversity are difficult to quantify, especially during uncertain times. In addition, the potential risks associated with added construction costs and other uncertainties associated with nuclear power raise additional questions on the merits of DEC's preferred plan."[1]

In their initial comments and reply comments, the Sierra Club and SACE agreed with the Public Staff, finding that further development of new nuclear generation is subject to numerous risks and uncertainties "weighing strongly against over-reliance on nuclear generation in the DEC and [DEP] IRPs."[2] Sierra Club and SACE contrasted the approach taken by DEC and DEP with TVA, which "evaluated the environmental impacts of each alternative resource portfolio in terms of air emissions, water impacts, and waste disposal costs (coal ash and nuclear) in its 2011 IRP." Sierra Club and SACE asserted that adopting a broader approach, similar to that used by TVA, would allow DEC and DEP to be more explicit about how to balance various environmental risks. Sierra Club and SACE also recommended that the uncertain costs associated with the handling and storage of nuclear waste be both discussed and quantitatively assessed in the utilities' resource evaluations.

Sierra Club and SACE also noted in their initial comments the large number of coal-fired units that DEC and DEP have retired or are scheduled to retire in the next few years due to more stringent environmental regulations that apply to coal-fired units. Similar to the argument they made in the 2010 IRP proceeding, Sierra Club and SACE noted that these regulations also pose risks to the utilities' remaining facilities, including those that are already equipped with emissions controls such as scrubbers. Sierra Club and SACE recommended that the electric power suppliers include in their IRPs a more detailed discussion of regulatory risks faced by their coal fleet, including scrubbed plants, and impending regulations, including information on any investments required in further pollution control equipment or increased operating expenses.

DNCP evaluated the following four generation portfolios: Plan A or its Base Plan, which consists of all natural gas facilities; Plan B or its Fuel Diversity Plan, which consists of a combination of new natural gas-fired CTs, CCs, 248 MW of onshore wind, 10 MW of solar, and a new nuclear unit located at the North Anna site; Plan C or its Renewable Plan, which includes 100 MW of generic biomass, 248 MW of onshore wind, 1,600 MW of offshore wind, 20 MW of solar, and a combination of new natural gas-fired CTs and CCs; and Plan D or its Coal Plan, which includes the development of two 695-MW coal-fired facilities equipped with carbon capture and sequestration technology, along with a combination of new natural gas-fired CTs and CCs. Following its evaluation, DNCP selected its Plan B, Fuel Diversity, as its preferred plan, despite the fact that Fuel Diversity Plan, under current planning assumptions, produces a higher cost than its Base Plan.

In its comments, the Public Staff noted that the concerns it expressed about the risks of relying on nuclear generation in DEC's plan also apply to DNCP. The Public Staff recommended that an electric utility that selects a preferred plan based on fuel diversity elaborate and provide additional support for its decision in its reply comments. The Pubic Staff also stated that:

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[1] Public Staff initial comments at 58-59.

[2] Sierra Club and SACE reply comments at 11.

> The electric utility industry has experienced significant changes in recent years and will continue to face a great deal of uncertainty. Each of the utilities discussed in its IRP the evolving commodity and technology trends that have resulted in substantial changes in the landscape. Hydraulic fracturing and the production of shale gas have pushed down natural gas prices and may transform the energy market for decades to come. The environmental and regulatory risks of shale gas production, however, remain uncertain. In addition, other changes, such as smart grid technologies and generation using renewable energy resources, present new challenges and opportunities as they continue to develop. Finally, regulations at both the state and federal levels have the potential to substantially change a utility's preferred resource mix. [1]

In addition, the Public Staff recommended that to the extent a utility selects a preferred plan based on circumstances that may exist beyond the planning period the utility should provide a justification for its reliance or consideration of those circumstances.

In its reply comments, DNCP noted that in addition to the expiration of the operating licenses for two of DNCP's four nuclear units during the study period (Surry Units 1 and 2), two additional units (North Anna Units 1 and 2) have license expirations that occur shortly after the study period. DNCP stated that '[n]uclear plant operating licenses have a known finite life, and recognition of the expiration of these major generating facilities' operating licenses is a reasonable consideration for DNCP to use in evaluating its choice of the preferred plan." DNCP acknowledged that its preferred plan under current planning assumptions is a higher cost than the base plan, but DNCP maintains that "the Preferred Plan will provide fuel-price stability for customers over the long-term by reducing an over-reliance on any one fuel source (namely, gas) and/or generation technology at the lowest reasonable cost." DNCP stated that its current customers are benefitting substantially from the Company's historic investments in nuclear, and that the Preferred Plan does include the addition of 3,550 MW of new natural gas capacity, as well as additional nuclear, wind, and solar resources. In response to the Public Staff's recommendation, DNCP indicated that it will develop additional support should it determine that a fuel diversity plan is the preferred plan over the Base Plan in its next North Carolina IRP.

The Commission recognizes that diversity in a utility's resource mix may help to protect the utility and its customers from fuel price fluctuations, fuel unavailability, and regulatory uncertainties, and may also ensure stability and reliability in the State's electricity supply. Fuel diversification, however, must be justified by an analysis of the benefits and costs of alternatives to achieve the same objectives. DEC's IRP indicates that the benefits of fuel diversity associated with a new nuclear facility may come at an additional cost of $3.5 billion to $3.8 billion under certain scenarios. Similarly, DNCP's reply comments and the Public Staff's comments recognize the higher cost associated with the benefits of fuel diversity with nuclear generation over the Company's Base Plan. The Commission agrees that the potential benefits of fuel diversification warrant further consideration, and concurs with the Public Staff that to the extent an IOU selects a preferred resource plan based on fuel diversity, the IOU should elaborate and provide

[1] Public Staff initial comments at 61-62.

additional support for how its decision complies with the statutory requirement of least-cost planning.

Concerns Raised by NC WARN, et al.

In their initial comments, NC WARN, et al., also expressed their opinions and concerns over several aspects of DEC and DEP's IRPs, including the following:

1) Expenditures on power plant construction that divert resources that could otherwise be utilized for weatherization and EE projects.
2) The much higher percentage of electricity that could be sourced from EE and renewable resources.
3) The IRPs do not reflect the economic potential for renewable energy resources and do not consider the potential of customer co-generation or combined heat and power (CHP).
4) The timing and escalating costs of nuclear plant construction pose significant economic risks to ratepayers, and the continued use of fossil fuels also raises significant environmental costs.

To support their positions, NC WARN, et al., attached two reports. The first, a Greenpeace report entitled, "Charting the Correction Course: A Clean Energy Pathway for Duke Energy," utilized some of the same modeling tools used by DEC and PEC, with different assumptions. Based on the Greenpeace Plan, NC WARN, et al., indicated that the overall costs of DEC and DEP's IRPs would decrease, while at the same time emissions would also be significantly reduced.

In their reply comments, DEC and DEP challenged the assumptions and methodology underlying the proposals submitted by NC WARN, et al., stating that the proposals are not realistic if "North Carolina wants to ensure reliable and affordable electricity are available to residential, commercial, and industrial customers, as the Companies are obligated to do."[1] Further, DEC and DEP asserted that their IRPs present a robust and balanced portfolio that will cost-effectively and reliably serve customer's short and long-term needs across a range of possible future scenarios.[2]

The Commission recognizes the efforts of Greenpeace and others to develop alternative models and IRPs that test the inputs and assumptions that go into utility resource planning, but concludes that the plans proposed by the utilities are reasonable for planning purposes.

[1] DEC and DEP reply comments at 11.

[2] Id.

DISCUSSION AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 15-16

In its March 21, 2007, Order Granting Certificate of Public Convenience and Necessity with Conditions for Cliffside Unit 6, in Docket No. E-7, Sub 790, the Commission ordered DEC to retire, in addition to Cliffside Units 1-4, "older coal-fired generating units . . . on a MW-for-MW basis, considering the impact on the reliability of the entire system, to account for actual load reductions realized from [new EE and DSM] programs, up to the MW level added by" Cliffside Unit 6, i.e., 825 MW.[1] In the air permit issued by the North Carolina Department of Environment and Natural Resources, Division of Air Quality (DAQ) for Cliffside Unit 6, DAQ required DEC to implement a Greenhouse Gas Reduction Plan and to retire 800 MW of additional coal capacity without regard to achieving a commensurate level of MW savings from new EE and DSM programs. DEC's Greenhouse Gas Reduction Plan can be revised with DAQ's approval if the Commission determines that the scheduled retirement of any unit will have a material impact on the reliability of DEC's system.

In its 2011 and 2012 IRPs, DEC has included as Appendix J a Cliffside Unit 6 Carbon Neutrality Plan. This Plan incorporates actions required under the Greenhouse Gas Reduction Plan, as well as those required under DEC's additional obligations related to its Cliffside Unit 6 air permit to: (a) retire 800 MW of coal capacity in North Carolina in accordance with the schedule set forth in Table J.1, (b) accommodate to the extent practicable the installation and operations of future carbon control technology at Cliffside Unit 6, and (c) take additional actions as necessary to make Cliffside Unit 6 carbon neutral by 2018. Table J.1 indicates that DEC plans to cumulatively retire 1,299 MW of coal capacity, not including Cliffside Units 1-4, by the end of 2015.[2] The projected retirements under the Cliffside Unit 6 Carbon Neutrality Plan would exceed the requirements of the Greenhouse Gas Reduction Plan by close to 70%. DEC states that some older coal-fired units that are currently planned for retirement might instead be converted to natural gas. However, DEC will still greatly exceed the requirements of the Greenhouse Gas Reduction Plan, even with the possible coal-to-gas conversions.

Consistent with the 2011 IRP Order, the Public Staff recommended that the Commission approve the Cliffside Unit 6 Carbon Neutrality Plan as a reasonable path for DEC's compliance with the carbon emission reduction standards of the air quality permit, but state that it is not approving any individual specific activities or expenditures for any activities shown in the Plan. The Public Staff recommended that DEC continue to provide updates in future IRPs regarding its obligations related to the Cliffside Unit 6 air permit.

The Commission agrees with the Public Staff's recommendation. Therefore, the Commission concludes that the Cliffside Unit 6 Carbon Neutrality Plan is a reasonable path for DEC's compliance with the carbon emission reduction standards of the air quality permit;

[1] Order Granting Certificate of Public Convenience and Necessity with Conditions for Cliffside Unit 6, On March 21, 2007, in Docket No. E-7, Sub 790, at 140.

[2] On February 1, 2013, DEC announced the closure of Riverbend Units 4-7 and Buck Units 5 and 6 in April 2013. These units were listed in Table J.1 as closing by 2015.

however, the Commission notes that this conclusion does not constitute approval of any individual specific activities or expenditures for any activities shown in the Plan.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 17

2012 REPS COMPLIANCE PLANS

All of the electric power suppliers in this proceeding indicated that they will achieve the general and solar requirements in G.S. 62-133.8(b), (c), and (d) for the planning period. They also indicated that their expenses to comply with the REPS in the planning period would not exceed the annual cost caps established in G.S. 62-133.8(h)(3) and (4).

In its REPS compliance plan, DEC stated that because of uncertainty with environmental permit requirements, it has reduced its reliance on biomass for future REPS compliance. DEC noted that it will continue to pursue wind energy, either through REC-only purchases or through energy delivered to its customers in North Carolina to meet the in-state general requirement. However, the Commission notes that continuation of the federal production tax credit is uncertain, and repeal of the credit could limit future wind projects.[1]

DEP's REPS compliance plan indicated that it had implemented its Commercial and Residential SunSense programs to help it comply with the solar set-aside requirement of G.S. 62-133.8(d). The Residential SunSense program, which incentivizes solar PV systems up to 10 kW, was modified in February 2013 to reduce the up-front rebate paid to participants from $1 per watt to $0.50 per watt.

Halifax plans to meet the general REPS requirements for itself and the Town of Enfield through its EE programs, SEPA allocations, and out-of-state wind RECs. In its comments, the Public Staff noted that Halifax did not provide an M&V plan as required in R8-67(b)(1)(iii), and recommended that it file an M&V plan with its next REPS compliance plan.

In its reply comments filed on March 5, 2013, Halifax provided additional details regarding its means of verification for each of its programs, but stated that "given its numbers of members and limited staff any additional requirements for measurement and verification of these programs would not be a cost-effective use of Cooperative resources."[2] Halifax requested that the Commission accept the measures utilized by Halifax as sufficient for each of the EE programs. As the Commission discussed in its May 14, 2012, Order in Docket No. E-100, Sub 113, the Commission recognizes that electric power suppliers that have small customer bases also have low REPS cost caps, and that rigorous M&V protocols may be inappropriate in some cases, with the cost quickly dwarfing the economic value of the energy savings being

[1] Section 407 of the American Taxpayer Relief Act of 2012 (P.L. 112-240, enacted on January 2, 2013) modified the eligibility criteria for the federal production tax credit for energy produced from qualifying renewable energy resources, including wind, by: (1) removing "placed in service" deadlines and replacing them with deadlines that use the beginning of construction as a basis for determining facility eligibility; and (2) extending the deadline for wind energy facilities by one year, from December 31, 2012, to December 31, 2013.

[2] Halifax reply comments at 2.

measured. The Commission notes that Halifax submitted with its 2013 REPS compliance plan (Docket No. E-100, Sub 139) worksheets demonstrating how it calculated the energy savings for each of its EE programs. The Commission finds the level of data provided by Halifax in its 2013 submittal to be appropriate.

Swine and Poultry Waste Set-Asides in G.S. 62-133.8(e) and (f)

Several electric power suppliers indicated in their 2011 REPS compliance plans that they have had difficulty in obtaining RECs to comply with the swine and poultry waste set-asides in G.S. 62-133.8(e) and (f), which require them to meet a portion of their REPS obligations with energy derived from swine waste and poultry waste beginning in 2012. On May 16, 2012, the Commission issued an Order in Docket No. E-100, Sub 113, requiring the electric power suppliers to file an update on their efforts in meeting these compliance requirements. On June 1, 2012, the electric power suppliers filed a Joint Motion seeking to delay the swine and poultry waste set-asides as allowed in G.S. 62-133.8(i)(2). The joint movants claimed that they have had difficulty acquiring RECs to meet the swine and poultry waste set-asides because the technology for waste-to-energy facilities is still in its infancy and will need more time to reach maturity. A number of parties intervened in the docket, including three developers of waste-to-energy facilities, who indicated that they had had difficulty negotiating contracts with some of the electric power suppliers because of the lack of a standard contract form and lack of information on terms and conditions.

On November 29, 2012, the Commission issued an Order eliminating the 2012 swine waste set-aside requirement, delaying by one year the poultry waste set-aside requirement, requiring DEC and DEP to file triennial reports describing the state of their compliance with the set-asides and their negotiations with the developers of swine and poultry waste-to-energy projects, and requiring internet-available information to assist the developers of swine and poultry waste-to-energy projects in getting contract approval and interconnecting facilities.

In its comments, the Public Staff stated that it believes the electric power suppliers will likely continue to have difficulty meeting the swine and poultry waste set-asides even with a one-year delay. The Public Staff concluded that while all electric power suppliers are on course to meet the general and solar REPS requirements for the planning period, they will have difficulty meeting the Commission’s revised swine waste and poultry waste requirements in 2013 and possibly 2014, though they are actively seeking energy and RECs to meet these requirements. In addition, the Public Staff noted that the EMCs and municipalities have submitted REPS compliance plans that satisfy most or all of the filing requirements of Commission Rule R8-67(b). According to the Public Staff, the compliance plans also indicate that the electric power suppliers should be able to meet their REPS obligations during the planning period without nearing or exceeding their cost caps.

The Commission agrees that, with the exception of the swine and poultry waste set-asides, the 2012 REPS compliance plans submitted by the electric power suppliers indicate that they are generally well-positioned to comply with their future REPS obligations. The Commission therefore concludes that the 2012 REPS compliance plans filed in this proceeding by the electric power suppliers are satisfactory and should be approved. The Commission notes that on September 16, 2013, most of the electric power suppliers filed a joint motion requesting to be relieved of their 2013 swine and poultry waste obligations. On September 23, 2013, the Commission issued an Order in Docket No. E-100, Sub 113, scheduling an evidentiary hearing regarding the joint motion.

IT IS, THEREFORE, ORDERED as follows:

1. That this Order shall be adopted as part of the Commission's current analysis and plan for the expansion of facilities to meet future requirements for electricity for North Carolina pursuant to G.S. 62-110.1(c).

2. That the IOUs' 15-year forecasts of native load requirements and other system capacity or firm energy obligations, supply-side and demand-side resources expected to satisfy those loads, and reserve margins are reasonable and are hereby approved.

3. That the 2012 biennial IRP reports filed in this proceeding by the IOUs, NCEMC, Piedmont, Rutherford, EnergyUnited, and Haywood are hereby approved.

4. That the 2012 REPS compliance plans filed in this proceeding by the IOUs, GreenCo, Halifax, and EnergyUnited are hereby approved.

5. That future IRP filings by all IOUs shall continue to include a detailed explanation of the basis and justification for the appropriateness of the level of the respective utility's projected reserve margins.

6. That future IRP filings by all IOUs shall continue to include a copy of the most recently completed FERC Form 715, including all attachments and exhibits.

7. That future IRP filings by all IOUs shall continue to: (1) provide the amount of load and projected load growth for each wholesale customer under contract on a year-by-year basis through the terms of the current contract, segregate actual and projected growth rates of retail and wholesale loads, and explain any difference in actual and projected growth rates between retail and wholesale loads, and (2) for any amount of undesignated load, detail each potential customer's current supply arrangements and explain the basis for the utility's reasonable expectation for serving each such customer.

8. That each IOU shall continue to include a discussion of a variance of 10% or more in projected EE savings from one IRP report to the next.

9. That each IOU shall continue to include a discussion of the status of EE market potential studies or updates in their future IRPs.

10. That all IOUs shall include in future IRPs a full discussion of the drivers of each class' load forecast, including new or changed demand of a particular sector or sub-group.

11. That, pursuant to the Regulatory Conditions imposed in the Merger Order, DEC and DEP shall continue to pursue least-cost integrated resource planning and file separate IRPs until otherwise required or allowed to do so by Commission order or until a combination of the utilities is approved by the Commission.

12. That DEC shall continue to provide updates in future IRPs regarding its obligations related to the Cliffside Unit 6 air permit.

13. That the Cliffside Unit 6 Carbon Neutrality Plan filed by DEC is approved as a reasonable path for DEC's compliance with the carbon emission reduction standards of the air quality permit; provided, however, this approval does not constitute Commission approval of individual specific activities or expenditures for any activities shown in the Plan.

14. That in their future IRP filings, DEP and DNCP shall provide additional details and discussion of projected alternative supply side resources similar to the information provided by DEC.

15. That in future IRPs, DEC and DEP should consider additional resource scenarios that include larger amounts of renewable energy resources similar to DNCP's Renewable Plan, and to the extent those scenarios are not selected, discuss why the scenario was not selected.

16. That, to the extent an IOU selects a preferred resource scenario based on fuel diversity, the IOU should provide additional support for its decision based on the costs and benefits of alternatives to achieve the same goals.

17. That, consistent with the Commission's May 7, 2013 Order in Docket No. M-100, Sub 135, the IOUs shall include with their 2014 IRP submittals verified testimony addressing natural gas issues, as detailed in the body of that Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 14th day of October, 2013.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

mr101413.01

Former Commissioners William T. Culpepper, III and Lucy T. Allen, and present Commissioners Don M. Bailey, Jerry C. Dockham, and James G. Patterson did not participate in this decision.

DOCKET NO. E-100, SUB 138

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Rulemaking Proceeding to Standardize the Indices Used to Measure and Report Electric Utility Service Quality	)))))	ORDER ADOPTING RULE ESTABLISHING ELECTRIC UTILITY SERVICE QUALITY METRICS AND REQUIRING FILING OF QUARTERLY REPORTS AND REQUESTING FURTHER COMMENTS

BY THE COMMISSION: On January 25, 2013, the Commission issued an Order Requesting Comments on Proposed Rule to establish electric utility service quality metrics for all electric public utilities currently subject to the Commission's integrated resource plan filing requirements under Commission Rule R8-60. In its Order, comments were to be filed on or before Monday, February 25, 2013, and reply comments were to be filed on or before March 25, 2013.

BACKGROUND

On June 29, 2012, the Commission issued an Order Approving Merger Subject to Regulatory Conditions and Code of Conduct in Docket Nos. E-2, Sub 998 and E-7, Sub 986 (Merger Docket). In Ordering Paragraph No. 22, the Commission directed "Duke Energy Carolinas, LLC (DEC), Progress Energy Carolinas, Inc. (PEC),[1] and the Public Staff to work with other interested parties to propose within 90 days after the close of the merger a Commission rulemaking to standardize the indices used to measure and report electric utility service quality".

On July 2, 2012, the merger transaction was closed.

On September 28, 2012, in response to a motion by DEC and PEC (the Companies), the Commission issued an order in the Merger Docket extending the time for the Companies to file the proposed rulemaking to November 5, 2012.

On November 5, 2012, the Companies filed a Status Report and Motion for Extension of Time to File Proposed Rulemaking Pursuant to Ordering Paragraph 22 in the Merger Docket requesting that the Commission extend the time to file the proposed rulemaking to November 26, 2012, stating that they had met with the Public Staff to discuss the draft rule. The draft rule consisted of two specific service quality indices: the System Average Interruption Duration Index (SAIDI), which indicates the total duration of interruption for the average customer during a predefined period of time, typically one year; and, the System Average Interruption Frequency Index (SAIFI), which indicates how often the average customer experiences interruptions. A copy of the proposed rule containing the proposed definitions was also provided to Dominion North Carolina Power (DNCP) for its review and comment. In addition, the Companies stated that they believed that the North Carolina Electric Membership Corporation (NCEMC) was also

[1] On April 29, 2013, Progress Energy Carolinas, Inc. became Duke Energy Progress, Inc.

interested in participating in the discussions concerning a proposed rule. The additional time, if granted, was to allow the parties to reach consensus on the proposed rule.

On November 7, 2012, the Commission issued an Order granting the extension of time.

On November 26, 2012, the Companies and the Public Staff (the Parties) filed a Petition, in the above captioned docket, to Standardize Electric Service Quality Indices, in which they proposed a Commission rule formalizing and standardizing the requirements for reporting the reliability of electric utility service by electric public utilities operating in the State. The Parties stated that the proposed rule provided that the electric utilities would report SAIDI and SAIFI data on a quarterly basis. The Parties stated that, in drafting this proposed rule, the Parties referred to the Institute of Electrical and Electronics Engineers (IEEE) Guide for Electric Power Distribution Reliability Indices 1366-2012 (IEEE Standard 1366). The Parties further stated that IEEE Standard 1366presents a set of terms and definitions that are intended to make reporting practices consistent and to enable comparisons between and among the electric public utilities.

The Parties stated that, at this time, there are no formal Commission requirements for reporting the reliability of electric utility service by the electric public utilities operating in the State. The Parties also noted that, after DNCP's review, the Parties and DNCP were unable to reach consensus to apply the proposed rule to all electric public utilities in the State. Also, NCEMC declined to join in proposing this rule to the Commission.

In response to the January 25, 2013 Order, comments were filed jointly by Piedmont Electric Membership Corporation (Piedmont), Rutherford Electric Membership Corporation (Rutherford), and EnergyUnited Electric Membership Corporation (EnergyUnited); NCEMC; and DNCP on February 25, 2013. Joint reply comments were filed by the Companies on April 8, 2013. Also on April 8, 2013, the Public Staff filed a letter in lieu of reply comments.

COMMENTS

<u>NCEMC</u>

NCEMC, on behalf of its member electric membership corporations (EMCs), requested that the Commission revert to the initial version of the draft rule which was to apply solely to the Companies. NCEMC further stated that, "absent some compelling reason to include the EMCs, it seems appropriate to spare EMC member/consumers the cost and inconvenience of additional regulatory burden." NCEMC stated that this rulemaking resulted from the express condition of the merger between DEC and PEC.

NCEMC noted that the purpose of this rulemaking initially was to monitor service reliability, safety, and dependability of the Companies after the merger because of the potential pressure to attain cost savings and earnings growth. NCEMC stated that its members are transmission-dependent load serving entities and rely on the Companies and DNCP as the transmission providers for EMC services territories. NCEMC further commented that the EMCs should be excluded from this rulemaking since there are no service problems or shortfalls in EMC service quality.

Piedmont, Rutherford, and EnergyUnited

Piedmont, Rutherford, and EnergyUnited commented that they summarily agree with the comments filed by NCEMC and that they should be excluded from this rulemaking. Further, Piedmont, Rutherford, and EnergyUnited stated that this rulemaking should not be extended to electric service providers that are not "public utilities." Piedmont, Rutherford, and EnergyUnited stated that their decision to be responsible for procurement of any or all of their respective individual power supply resources, and thereby being subject to the requirement to file an integrated resource plan pursuant to Rule R8-60, is unrelated to issues pertaining to their distribution systems and retail service, such as the measuring and reporting of electric utility quality that is the subject of this docket.

DNCP

DNCP commented that it has provided quarterly service reliability reports to the Commission containing SAIDI and SAIFI index statistics since the year 2000 pursuant to the Commission's Order Approving Merger issued on October 18, 1999, in Docket No. E-22, Sub 380 and its Order Closing Docket and Opening New Docket issued on March 6, 2002, in Docket No. E-22, Subs 380 and 380A. Although DNCP stated that it can provide SAIDI and SAIFI data in accordance with IEEE Standard 1366, it has three recommendations regarding the rulemaking.

First, DNCP recommended that the Commission remove the definitions from the rule that replicate definitions contained in IEEE Standard 1366 and consider, instead, stating in the rule that terms not defined in the rule are defined by IEEE Standard 1366. Therefore, changes to the rule made by the Commission could be done consistent with IEEE Standard 1366 as well as any changes made by the IEEE to IEEE Standard 1366.

Second, DNCP recommended that the Commission allow a utility, where practical and identified by the utility as appropriate, to alter the standards contained in the rule and, by reference, IEEE Standard 1366. DNCP stated that, for example, it defines a sustained interruption as an interruption lasting more than two minutes, whereas a sustained interruption is defined in IEEE standard 1366 as one lasting more than five minutes.

Third, DNCP recommended that the rule should permit individual utilities to select a method to exclude catastrophic events from their calculations of service quality reported as SAIDA and SAIFI data. DNCP commented that it currently excludes catastrophic events from its reporting.

REPLY COMMENTS

The Companies

In reply, the Companies stated they did not agree that the rule should only apply to themselves. The Companies commented that, because DNCP files SAIDI and SAIFI reports, DNCP should be included in the standardization of the reporting requirements. The Companies stated that a rulemaking typically does not apply to one or two entities in a service sector, but rather, to an entire sector. The Companies noted that, in the Merger Order, the Commission did not limit the applicability of the rulemaking to the Companies only.

The Companies commented on DNCP's first recommendation stating they agree that the Commission should remove from the rule those definitions already contained in IEEE Standard 1366 and state that the terms not defined in the rule are defined by the current version of IEEE Standard 1366. The Companies suggested that reports provided pursuant to the rule would be accomplished by the electric public utilities consistent with the current version of IEEE Standard 1366.

The Companies, however, did not agree to DNCP's second recommendation to allow the utilities to use their own definitions where practical and identified as appropriate. The Companies commented that standardization is necessary to allow comparisons on reliability between the electric utilities. As they further stated, if the reporting metrics of these individual utilities differ, the reports will be inconsistent, and any meaningful comparisons between and among the utilities will be impossible.

The Companies also do not agree with DNCP's third recommendation to allow the electric utilities to "permit the individual utilities to select a method to exclude catastrophic events" from the SAIDI and SAIFI reported indices. The Companies stated that IEEE Standard 1366 does not define catastrophic event; without such a standard definition, it would be left to the reporting utilities to define such an event.

In summary, the Companies stated they believe that the definitions in IEEE Standard 1366, as set forth in the revised rule, are sufficient to accomplish the Commission's goal of consistent and comparable reporting by the electric utilities of their SAIDI and SAIFI data. The Companies stated that, in addition to its current quarterly filing requirement of SAIDI and SAIFI indices, DNCP should also be required to file the same data each quarter as other utilities.

<u>The Public Staff</u>

In its letter filed in lieu of reply comments, the Public Staff stated that it had reviewed all of the filed comments and a draft of the joint comments to be filed by the Companies. The Public Staff stated that it concurs with the Companies' joint reply comments and requests that the Commission adopt the proposed rule with the revisions recommended therein.

DISCUSSION AND CONCLUSIONS

On June 26, 2013, Session Law 2013-187 (House Bill 223), entitled An Act Exempting Electric Membership Corporations From Integrated Resource Planning and Service Regulations Requirements Established by the Utilties Commission, Returning Oversight of the Corporations to Their Member Board of Directors, and Clarifying the Authority of the North Carolina Rural Electrification Authority to Receive and Investigate Complaints from Members of Electric Membership Corporations (the Act), was signed into law effective July 1, 2013. Section 2 of the Act exempts EMCs from the requirement to file integrated resource plans with the Commission. The Act further removes EMCs from service regulations requirements established by the Commission and returns oversight of the EMCs to their member boards of directors. Consistent with the purpose and intent of the Act, the Commission, therefore, concludes that the EMCs should be excluded from the service reliability indices reporting requirements in this rulemaking.

With regard to the electric public utilities, the Commission concludes that the adoption of IEEE Standard 1366, as proposed for use in this rulemaking, will provide a reasonable indicator of network service quality among the public utilities providing electric service across the State. Also, the adoption of the proposed rule will provide consistent and comparable information from the electric public utilities concerning the ongoing reliability of their systems.

After careful consideration, the Commission, therefore, concludes that the Companies and DNCP should be required to submit SAIDI and SAIFI data on a quarterly basis for the preceding 12 months within 30 days of the end of each quarter beginning with the quarter ending December 31, 2013. The SAIDI and SAIFI indices are to be reported, as defined, in the attached rule, which adopts IEEE Standard 1366. The Commission finds that the adoption of this rule will provide consistent and comparable publicly available data pertaining to the continued reliability of the electric service provided by the electric public utilities in this State. Lastly, although proposed by the Companies to be included as a new Rule R8-42, which would replace the previously rescinded rule in Article 8, Electric Energy Supply Planning, of Chapter 8 of the Commission's Rules and Regulations, the Commission concludes that the proposed rule more appropriately should be added to Article 7, Power Reliability, which already includes a rule on reporting of service interruptions in bulk electric power supply and related power supply facilities.

The Commission, in addition to addressing network reliability among the electric utilities, is also interested in addressing the adoption of indices relating to customer service satisfaction similar to those required of other utilities subject to the Commission's jurisdiction. As such, the Commission is requesting that the parties in this rulemaking discuss the development of customer service satisfaction indices, such as Average Customer Call Answer Time, Complaint Response Time, New Service Installation Factor, Commission Complaint Rate, etc. The Commission, therefore, finds good cause to request further comments on whether the reporting of such additional service indices should be required by electric public utilities. Discussion of the following questions would be beneficial to the Commission in weighing its decision regarding further rulemaking in this matter: (1) Are the suggested indices measurable and reportable? (2) What is the appropriate basis to establish the target objective for the measurement, historically trended data or on a statistical basis? (3) Should the proposed indices be reported quarterly or on some other interval? (4) Are there other service quality or customer relations factors or indices which should be evaluated and reported to better gauge company performance?

IT IS, THEREFORE, ORDERED as follows:

1. That DEC, PEC, and DNCP shall file with the Commission on a quarterly basis SAIDI and SAIFI data for the preceding 12 months within 30 days of the end of each quarter beginning with the quarter ending December 31, 2013.

2. That Commission Rule R8-40A, Service Reliability Index Reporting, attached hereto as Appendix A, shall be, and is hereby adopted effective as of the date of this Order.

3. That DEC, PEC, DNCP, the North Carolina Attorney General, and the Public Staff are requested to file comments and reply comments on the adoption of further customer indices, as discussed herein. Comments shall be filed on or before January 24, 2014, and reply comments shall be filed on or before February 21, 2014.

4. That the Service Reliability Index Reports shall be filed by the utilities in Docket No. E-100, Sub 138A.

ISSUED BY ORDER OF THE COMMISSION.
This the 25th day of November, 2013.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

ATTACHMENT A

R8-40A Service Reliability Index Reporting

(a) Purpose. The purpose of this Rule is to establish standards for measuring and reporting distribution service reliability by electric public utilities that own and operate electric power distribution systems in North Carolina.

(b) Applicability. This Rule applies to Duke Energy Carolinas, LLC; Duke Energy Progress, Inc.; and Dominion North Carolina Power.

(c) Definitions. Unless otherwise provided for in this Rule, all terms used are as defined by the Institute of Electrical and Electronics Engineers (IEEE) in the most current IEEE Guide for Electric Power Distribution Reliability Indices 1366 (IEEE Standard 1366).

(d) Quarterly Reports.

(1) Each electric public utility shall report service reliability data to the Commission on a quarterly basis. The data reported shall be submitted within 30 days of the end of each quarter and shall reflect SAIDI and SAIFI results for the preceding 12 months.

(2) SAIDI and SAIFI shall be calculated in accordance with IEEE Standard 1366.

(3) The reports shall include: SAIDI, with and without Major Event Days, and SAIFI, with and without Major Event Days.

(4) Interruptions reported shall include all sustained interruptions, except those for Major Event Days.

DOCKET NO. SP-100, SUB 30

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Request for Declaratory Ruling by Clean Energy, LLC	))	ORDER ON REQUEST FOR DECLARATORY RULING

BY THE COMMISSION: On January 17, 2013, in the above captioned proceeding, Clean Energy, LLC (Clean Energy), filed a Request for Declaratory Ruling stating that "[p]otential purchasers of [renewable energy certificates (RECs)] earned by facilities proposed for Clean Energy's Reventure Park have requested additional certainty that RECs earned from the capture and use of waste heat are eligible for triple credit beyond the statements of the Commission in its ruling in Docket No. SP-100, Sub 28." In its filing, Clean Energy requests that the Commission issue an Order with six specific declarations regarding the aforementioned issues.

On January 22, 2013, the Commission issued an Order Requesting Comments, allowing for parties to intervene and file comments and reply comments on Clean Energy's request.

On February 1, 2013, Electricities of North Carolina, Inc., North Carolina Municipal Power Agency Number 1, and North Carolina Eastern Municipal Power Agency (hereinafter collectively referred to as the Power Agencies) filed a petition to intervene in this docket, which was granted by the Commission on February 6, 2013.

Comments were filed by the Public Staff on February 13, 2013, and by the Power Agencies on February 15, 2013. No other parties filed comments in this docket.

In its comments, the Public Staff, supporting Clean Energy's request, stated that "any 'waste heat [used] to produce electricity or useful, measurable thermal or mechanical energy at a retail electric customer's facility' from the first 20 MW of generating capacity should also be eligible for triple credit." Further, the Public Staff agreed that S.L. 2011-279, which amended Section 4 of S.L. 2010-195, "limited the ability of the additional credits to be utilized to meet the requirements of the poultry waste set-aside in G.S. 62-133.8(f) to the first 10 MW of biomass renewable energy facility generation capacity, but it did not affect the overall application of the triple credit provision to the renewable generation from the first 20 MW of biomass renewable energy generation capacity." In conclusion, the Public Staff recommended that the Commission issue an Order stating the six declarations requested by Clean Energy.

In their comments, the Power Agencies addressed each of the six declarations requested by Clean Energy, describing them as consistent with prior Commission Orders; S.L. 2010-195, as amended by S.L. 2011-279; and the intent of the Renewable Energy and Energy Efficiency Portfolio Standard. The Power Agencies recommended that the Commission issue an Order stating the six declarations requested by Clean Energy.

DISCUSSION AND CONCLUSION

On April 18, 2011, in Docket No. SP-100, Sub 28, the Commission issued an Order on Request for Declaratory Ruling, which, among other things, addressed the eligible output, pursuant to S.L. 2010-195 (Senate Bill 886), to which triple credit is applied to any electric power or RECs generated by an eligible facility. In its April 18, 2011 Order, the Commission stated:

> The Commission notes that Senate Bill 886 states simply that "[t]he triple credit shall apply only to the first 20 megawatts of biomass renewable energy facility generation capacity located in all cleanfields renewable energy demonstration parks in the State." The limit, therefore, is on the electric generating capacity of the facility or facilities, not the energy or RECs that may be earned by the facility or facilities. For example, if the BTE Facility were a combined heat and power facility, it could earn RECs associated with both the electric generation and the "waste heat [used] to produce electricity or useful, measurable thermal or mechanical energy at a retail electric customer's facility." As provided in Senate Bill 886, the triple credit is applied to any electric power or RECs generated from renewable energy resources at the biomass renewable energy facility that are purchased by an electric power supplier for the purposes of compliance with G.S. 62-133.8. The Commission agrees with ReVenture, therefore, that, under Senate Bill 886, any electric generating capacity beyond 20 MW located in cleanfields renewable energy demonstration parks in the State are not eligible for the triple credit. However, the Commission is not persuaded that Senate Bill 886 limits the number of RECs that may be earned by the first 20 MW of electric generating capacity to the electric power generated at the facility.

The Commission agrees with Clean Energy, the Public Staff, and the Power Agencies, and finds no reason why its April 18, 2011 Order is not still applicable. S.L. 2011-279 (Senate Bill 484) did not amend any aspect of S.L. 2010-195 with respect to the electric generating capacity that is eligible to earn triple credit. Rather, S.L. 2011-279 simply amended the electric generating capacity from which additional credits are eligible to satisfy the poultry waste set-aside requirement in G.S. 62-133.8(f). S.L. 2011-279 amended S.L. 2010-195 adding the following underlined language:

> The additional credits<u> assigned to the first 10 megawatts of biomass renewable energy facility generation capacity</u> shall be eligible for use to meet the requirements of G.S. 62-133.8(f). The additional credits<u> assigned to the first 10 megawatts of biomass renewable energy facility generation capacity</u> shall first be used to satisfy the requirements of G.S. 62-133.8(f). Only when the requirements of G.S. 62-133.8(f) are met, shall the additional credits<u> assigned to the first 10 megawatts of biomass renewable energy facility generation capacity</u> be utilized to comply with G.S. 62-133.8(b) and (c). The triple credit shall apply only to the first 20 megawatts of biomass renewable energy facility generation capacity located in all cleanfields renewable energy demonstration parks in the State

The effect of this language is that, although the first 20 MW of biomass renewable energy facility generating capacity remain eligible for the triple credit, only the first 10 MW of biomass renewable energy facility generating capacity is eligible to earn additional credits to meet the poultry waste set-aside requirements in G.S. 62-133.8(f). The additional credits from any generating capacity in excess of 10 MW must be utilized to comply with the general REPS requirements in G.S. 62-133.8(b) and (c), rather than the poultry waste set-aside requirement in G.S. 62-133.8(f). Consistent with the Commission's April 18, 2011 Order, the limit is on the electric generating capacity, not the amount of energy or RECs that may be earned, and RECS may be derived from both the electric generation and the waste heat used to produce electricity or useful, measurable thermal or mechanical energy at a retail electric customer's facility.

Based on its review of Clean Energy's request, the comments of the Public Staff and the Power Agencies, prior Commission Orders, and S.L. 2010-195, as amended by S.L. 2011-279, the Commission makes the following conclusions:

1. RECs eligible for triple credit pursuant to S.L. 2010-195, as amended by S.L. 2011-279, may be earned from the electric generation and the thermal energy produced from the capture and use of waste heat at a biomass fueled combined heat and power facility located in a cleanfields renewable energy demonstration park and registered with the Commission as a new renewable energy facility;

2. RECs eligible for triple credit pursuant to Section 4 of S.L. 2010-195, as amended by S.L. 2011-279, will be recorded in NC-RETS as one of two unique fuel types, marked either as originating from the first 10 MW of generating capacity, or as originating from the second 10 MW of generating capacity. If necessary, the allocation method of RECS between the first and second 10 MW of generating capacity will be determined during the registration of a cleanfields renewable energy demonstration park as a new renewable energy facility. Each megawatt-hour and every 3,412,000 British thermal units of useful thermal energy so recorded will equal a single REC of either type;

3. The electric power supplier that purchases either type of REC eligible for triple credit pursuant to Section 4 of S.L. 2010-195, as amended by S.L. 2011-279, for compliance with G.S. 62-133.8 will receive one REC. When the electric power supplier retires that REC, it will receive triple credit, resulting in one general obligation REC and two additional credits;

4. The electric power supplier will use and retire either type of REC eligible for the triple credit pursuant to Section 4 of S.L. 2010-195, as amended by S.L. 2011-279, and the two additional credits in accordance with the NC-RETS Operating Procedures;

5. The additional credits assigned to the first 10 megawatts of biomass renewable energy facility generation capacity are eligible for use to meet the requirements of G.S. 62-133.8(f) and they must first be used to satisfy those requirements. Only when the requirements of G.S. 62‑133.8(f) are met may the additional credits assigned to the first 10 MW of biomass renewable energy facility generation capacity be utilized to comply with G.S. 62-133.8(b) and (c); and

6. Except for the triple credit, all of the provisions of G.S. 62-133.8 and Rule R8-67 will apply equally to the RECs associated with the electric generation and thermal energy produced at a cleanfields renewable energy demonstration park as to RECs associated with energy produced at any other renewable energy facility.

IT IS, THEREFORE, SO ORDERED

ISSUED BY ORDER OF THE COMMISSION.
This the 11th day of March, 2013.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

Pb031113.01

DOCKET NO. P-100, SUB 110

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	ORDER INCREASING THE
Telecommunications Relay Service	)	TELECOMMUNICATIONS RELAY
(TRS), Relay North Carolina	)	SERVICE SURCHARGE

BY THE COMMISSION: On November 16, 2012, the North Carolina Department of Health and Human Services (DHHS) filed a petition requesting that the Commission approve an increase of the monthly Telecommunications Relay Service (TRS) surcharge pursuant to G.S. 62-157(b) and (c) from $0.11 to $0.14. TRS enables an individual with a hearing or speech disability to communicate by telephone with a person without such a disability. G.S. 62-157(b) and (c) directs the Commission to require local service providers to impose a monthly surcharge (set by the Commission) on qualified access lines and fund implementing and operating a relay service and an equipment distribution program, as well as a "reasonable margin for reserve."[1] The relay service and equipment distribution service comprise the Telecommunications Resources Program (TRP) (formerly called Telecommunications Access of North Carolina or TANC), which is administered by the Division of Services for the Deaf and Hard of Hearing, a division of DHHS. G.S. 62-157 provides that the funds from the surcharge on access lines are available to DHHS to operate and promote the service. In addition to funding from access lines, TRP receives funding through a surcharge pursuant to G.S. 62-157(i), which is collected by wireless providers and remitted to the Wireless 911 Board, which, in turn, remits the funds to DHHS. These funds are maintained in the Wireless TRS Fund. The amount of the wireless surcharge is the same as the access line surcharge that is set by the Commission.

The Commission set the current surcharge in a proceeding in 2011. On February 2, 2011, the Commission approved an increase in the surcharge to the current rate of $0.11 per access line.

In June 2012, pursuant to S.L. 2012-142 (the 2012 Budget Bill), Section 10.24(a), the General Assembly amended G.S. 62-157 (d1) to require DHHS to "utilize revenues from the wireless surcharge . . . to support the Division of Services for the Deaf and Hard of Hearing", thereby transferring 100% support of the Division to the TRS funds.

In its petition, DHHS stated that this amendment, coupled with under-realized projections of revenues resulting from the increase to $0.11, has resulted in the current surcharge providing revenues below actual expenditures.

DHHS stated in its petition that the reserve margin, as of the July 2012 budget report, is $2.2 million, below the $6.5 million set by the Commission. In addition, DHHS projects that TRP will experience an annual shortfall of revenues versus expenditures of $2.0 million. Thus, DHHS stated that the current surcharge can no longer support operational expenditures and must be increased to an amount that can sustain operations and restore the $6.5 million reserve.

[1] The current reserve margin of $6.5 million was approved by the Commission on July 7, 2010.

Accordingly, DHHS requests an increase to $0.14 to allow for continued operations and to slowly rebuild the reserve to $6.5 million.

The Public Staff presented this matter at the Commission's Regular Staff Conference on January 28, 2013. The Public Staff stated that it has reviewed the petition and that based on current expenditures and an analysis of projected access line and wireless line growth, the Public Staff believes that the $0.11 surcharge is not sufficient to support the operation of DSDHH, including TRP and the Regional Centers, and rebuild the reserve to the $6.5 million set by the Commission and recommends approval of the increase to $0.14 as requested by DHHS.

Based on the foregoing, and entire record in this matter, the Commission is of the opinion that the TRS surcharge should be increased as requested by DHHS and that notice should be given to customers of this increase.

IT IS, THEREFORE, ORDERED as follows:

1. That the monthly TRS surcharge shall be increased from $0.11 per access line to $0.14 per access line effective for bills issued on or after April 1, 2013. The increase shall be reflected on customers' bills issued on or after April 1, 2013.

2. That the bill message/insert as set forth in Appendix A shall appear on all customers' bills issued in the billing cycle immediately prior to the April 1, 2013 increase.

3. That DHHS shall revise the TRS surcharge remittance form to reflect the increase in the surcharge and shall post the revised form on the Telecommunications Resource Program website so as to make it available for downloading.

ISSUED BY ORDER OF THE COMMISSION.
This the 29th day of January, 2013.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

Pb012913.03

APPENDIX A

NOTICE OF TELECOMMUNICATIONS RELAY SERVICE (TRS) SURCHARGE INCREASE

Effective with telephone bills issued on or after April 1, 2013, the Telecommunications Relay Service (TRS) surcharge is $0.14 per access line, per month. On January 29, 2013, the North Carolina Utilities Commission authorized an increase in the monthly TRS surcharge amount from $0.11 to $0.14 to maintain adequate funding for Division of Services for the Deaf and Hard of Hearing (DSDHH), including the Telecommunications Resource Program (TRP) and the Regional Resource Centers within DSDHH. TRP is a program within the North Carolina

Department of Health and Human Services consisting of a telecommunications relay service that enables persons with hearing, speech, and vision impairments to communicate with others by telephone and an equipment distribution program. Regional Resource Centers provide a wide spectrum of services, including: (1) advocacy, consultation, workshops and training on a wide variety of topics pertaining to hearing loss; (2) communication support; (3) information and referral services; (4) assistance with selection, application for and set-up of equipment, training, and technical assistance as part of the equipment distribution service; and (5) outreach regarding available resources.

DOCKET NO. P-100, SUB 133f

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Lifeline and Link-Up Services Pursuant	)	ORDER ELIMINATING
to Section 254 of the Telecommunications	)	REQUIREMENT FOR LIFELINE
Act of 1996	)	SUBSIDY FUNDED BY THE
	)	STATE INCOME TAX CREDIT

BY THE COMMISSION: In accordance with guidelines established by the Federal Communications Commission (FCC) and orders issued by this Commission in Docket No. P-100, Sub 80[1], incumbent local exchange carriers (ILECs) and other designated eligible telecommunications carriers (ETCs) currently participate in a federal low income subsidy program for telephone service known as Lifeline. Under the current Lifeline program, eligible customers may receive a reduction in their local telephone rates if they have an income that is at or below 135 percent of the federal Poverty Guidelines or participate in at least one assistance program as outlined by the FCC. This reduction is currently funded through a combination of federal and state sources.

ILECs and other designated ETCs that provide subscribers with a reduction in their local service telephone rates are currently reimbursed through a credit against their North Carolina state income tax obligation authorized in G.S. 105-130.39. On July 23, 2013, North Carolina Session Law 2013-316 (House Bill 998), An Act to Simplify the North Carolina Tax Structure and to Reduce Individual and Business Tax Rates, was signed into law. Section 2.1.(b), of House Bill 998 repeals G.S. 105-130.39, effective January 1, 2014. Thus, as of that date, ILECs and other ETCs will no longer receive a credit against their North Carolina state income tax obligation to recover the reduction of the local service telephone rates for Lifeline subscribers.

[1] The subsidy program for local service rates began as the "Interstate Subscriber Line Charge Waiver Mechanism" under the federal lifeline assistance program in Docket No. P-100, Sub 80 and was enacted by Commission Order on February 24, 1986. The Commission in its Order Requiring Expanded Lifeline and Link-Up Services, dated November 5, 1997, established Docket No. P-100, Sub 133f to address Lifeline (and Link-Up) issues pursuant to the FCC's Universal Service Order. Since that time, revisions and amendments to the Lifeline (and Link-Up) program have been promulgated by Commission Order in Docket No. P-100, Sub133f.

On July 29, 2013, Session Law 2013-363 (House Bill 112), An Act to Make Technical, Clarifying, and Other Modifications to the Current Operations and Capital Improvements Appropriations Act of 2013 and to Related Legislation, was signed into law. In pertinent part, Section 11.1 of House Bill 112 amended G.S. 62-140(a) to add new language to read:

> If the State repeals any State funding mechanism for a reduction in the local telephone rates for low-income residential consumers, the Commission shall take appropriate action to eliminate any requirement for the reduced rate funded by the repealed State funding mechanism. For the purposes of this section, a State funding mechanism for a reduction in the local telephone rates includes a tax credit allowed for the public utility to recover the reduction in rates.

House Bill 112, thus, authorizes the Commission to take appropriate actions to eliminate any requirement for reduced rates for low income residential customers which is funded by the now repealed G.S. 105-130.39.

On August 30, 2013, the Commission issued its Order Requesting Comments. In the Order, the Commission requested initial comments from the Public Staff, ILECs, designated ETCs, and any other party to the docket by no later than October 1, 2013 and reply comments by no later than October 15, 2013 on appropriate actions to be taken by the Commission as a result of these enactments.

On September 30, 2013, the Public Staff filed its comments.

On October 1, 2013, the North Carolina Telecommunications Industry Association, Inc., (NCTIA)[1] filed comments.

No reply comments have been filed.

DISCUSSION

In its comments, the Public Staff observed that the concept of universal service has been a major policy goal of the FCC and this Commission since the mid-1980s. In addition, the Public Staff noted that section 254(b)(5) of the federal Telecommunications Act of 1996 states: “there should be specific, predictable and sufficient Federal and State mechanisms to preserve and advance universal service. Lifeline service has been the mechanism adopted on the federal and state level for providing universal service support to low-income consumers.

[1] NCTIA regulated ILEC members include AT&T North Carolina, CenturyLink, Citizens Telephone Company, d/b/a Comporium Communications, Ellerbe Telephone Company, North State Telephone Company, d/b/a North State Communications, Town of Pineville d/b/a Pineville Telephone Company, the TDS Telecom Companies, Frontier Communications of the Carolinas Inc., Windstream North Carolina, LLC, Windstream Concord Telephone, Inc., Windstream Lexcom Communications, Inc, and Windstream Communications, Inc. Members of the NCTIA not regulated by the Commission include Atlantic Telephone Membership Corporation, Randolph Telephone Membership Corporation, Skyline Telephone Membership Corporation, Star Telephone Membership Corporation, Surry Telephone Membership Corporation, Tri-County Telephone Membership Corporation, Wilkes Telecommunications and Yadkin Valley Telephone Membership Corporation.

The Public Staff stated that Lifeline service was implemented in North Carolina in 1996 in accordance with guidelines established by the FCC. Lifeline subscribers in North Carolina currently receive a monthly credit on their bills of up to $12.75. Telephone companies providing Lifeline service currently receive federal universal service support in the amount of $9.25 per Lifeline subscriber per month and State support in the amount of $3.50 per month per Lifeline subscriber in the form of a state income tax credit pursuant to G.S. 105-130.39. The Public Staff also noted that "[a]s a result of the enactment of House Bill 998 and House Bill 112, respectively, the Commission must eliminate the requirement that providers of local telephone service offer low-income residential subscribers a monthly bill credit of $3.50 per subscriber funded by the State tax credit pursuant to G.S. 105-130.39".

The Public Staff further observed that the Lifeline program has provided benefits to North Carolina by increasing the number of subscribers with access to telephone service[1], that changes to the Lifeline program rules during the last 24 months have significantly reduced the number of subscribers taking advantage of the reduced rates, that many Lifeline subscribers now obtain service through non-traditional providers that do not participate in the State Lifeline program, and that it was uncertain of the impact that these changes would have on the continued provision of services to low income subscribers. The Public Staff thereafter concluded that it could not find any clear evidence that eliminating the $3.50 State credit for all Lifeline subscribers would unduly jeopardize the provision of universal service to low income subscribers. The Public Staff nevertheless recommended that the Commission require the Lifeline/Link-Up Task Force to monitor the Lifeline program for evidence that State Lifeline support should be reinstituted by creating and funding a State universal service fund.

In its comments, the NCTIA recommended that the Commission take the following actions:

1. Formally eliminate as of January 1, 2014, any requirement that an ILEC or ETC provide that portion of the Lifeline low income subsidy/reduced rate for local service currently funded by the repealed State tax credit mechanism;

2. Revisit any rule, regulation or Order issued in any docket concerning or relating to providing Lifeline subscribers with any State reduction in their local telephone rates, and to formally eliminate any related obligation an ILEC or an ETC may have; and,

3. To otherwise revisit any requirement implicated by the adoption of Session Law 2013-316 and take any and all other action necessary to eliminate any requirement for provision of the reduced rate funded by the repealed State funding mechanism.

After carefully considering the comments of the parties and the actions of the General Assembly, the Commission concludes that:

[1] A companion program, Link-Up Carolina, which is now only available to subscribers residing on tribal lands, provides subscriber discounts to the service connection fee and is funded entirely through federal mechanisms.

1. Any Commission imposed requirement included in any order, rule or regulation that providers of local telephone service offer low-income residential subscribers a monthly bill credit of $3.50 per subscriber funded by the State tax credit pursuant to G.S. 105-130.39 shall be null and void as of January 1, 2014; and,

2. The Lifeline/Link-Up Task Force should be required to monitor the Lifeline program for evidence that State Lifeline support should be reinstituted and to report such to the Commission if it so determines.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 28th day of October, 2013.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

Pb102813.01

DOCKET NO. P-100, SUB 170

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Tariff Filings Made by Local Exchange Carriers in Compliance with the Federal Communications Commission's Connect America Fund Order	)	ORDER GRANTING THE PUBLIC STAFF'S MOTION WITH CLARIFICATION

BY THE COMMISSION: On May 3, 2013, the Public Staff filed a Motion on Filing of Information Regarding July 1, 2013 Access Rate Changes.

In its Motion, the Public Staff requested that the Commission order the incumbent local exchange carriers (ILECs) to file revised tariffs and that certain competing local providers (CLPs) file notarized affidavits regarding the rate revisions necessary to comply with implementation of the provisions set forth in Part 51, Subparts H and J of the Federal Communications Commission's (FCC's) November 18, 2011 Universal Service Fund (USF) / Intercarrier Compensation (ICC) Transformation Order by no later than June 10, 2013.

The Public Staff further noted that it has reviewed last year's responses and compiled a list of carriers as reflected in Appendix A to its Motion that the Public Staff believes should submit responses. The Public Staff also provided a list of carriers as reflected in Appendix B to its Motion that the Public Staff believes would not need to file unless the carrier's status has changed from last year.

On May 6, 2013, the Commission issued an Order Requesting Comments on the Public Staff's Motion.

Initial comments were filed on May 13, 2013 by the North Carolina Telecommunications Industry Association (NCTIA)[1]. Reply comments were filed on May 15, 2013 by the Public Staff.

INITIAL COMMENTS

The NCTIA stated that it supports the Public Staff's Motion. The NCTIA specifically noted that it supports the Public Staff's recommendation that CLPs providing intrastate switched access services need only submit an affidavit from an authorized person with sufficient knowledge of the facts to demonstrate compliance with the FCC's rules for transitional intrastate switched access rates. The NCTIA stated that it wished to address two areas of the Public Staff's Motion which require clarification: (1) the effective date of revised intrastate switched access service tariffs; and (2) the type of documentation ILECs must submit to demonstrate parity.

First, the NCTIA asserted that the FCC has granted a limited waiver of 47 C.F.R. §§ 69.3(a), 51.705, 51.907, and 51.909 and has established an effective date for the July 2013 annual revised intrastate switched access service tariffs of July 2, 2013. The NCTIA noted that the Public Staff's Motion identifies July 1, 2013 as the effective date for the revised intrastate switched access rates. Therefore, the NCTIA requested that the Commission set an effective date of July 2, 2013, in compliance with the FCC's directive. The NCTIA further noted that this approach is consistent with the Commission's Order in 2012 making those access tariff changes effective July 3, 2012. Finally, the NCTIA recommended that the Commission allow any carrier that would prefer to implement new rates and rate structures on July 1, 2013 to do so.

Second, the NCTIA noted that the Public Staff's Motion proposes that ILECs not conducting a restructuring of their intrastate switched access rates be required to provide adequate documentation indicating the proposed intrastate access rates are at parity with interstate rates. The NCTIA requested clarification that ILECs not restructuring their intrastate switched access rates be permitted to provide a link to their interstate switched access tariff to show parity between ILEC intrastate and interstate switched access rates. The NCTIA stated that, similarly, ILECs restructuring only their terminating intrastate switched access rates should also be permitted to provide a link to their interstate switched access tariff rather than providing worksheets to show that intrastate rates equal interstate rates. The NCTIA maintained that in

[1] The NCTIA regulated members include AT&T North Carolina, CenturyLink, Citizens Telephone d/b/a Comporium Communications, Ellerbe Telephone Company, Frontier Communications of the Carolinas Inc., North State Communications, Pineville Telephone Company, TDS Telecom, Windstream North Carolina, LLC, Windstream Concord Telephone, Inc., Windstream Lexcom Communications, Inc., and Windstream Communications, Inc. Members of the NCTIA not regulated by the Commission include Atlantic Telephone Membership Corporation, Randolph Telephone Membership Corporation, Skyline Telephone Membership Corporation, Star Telephone Membership Corporation, Surry Telephone Membership Corporation, Tri-County Telephone Membership Corporation, Wilkes Telephone Membership Corporation, and Yadkin Valley Telephone Membership Corporation.

both of these instances, reference to the interstate tariff would permit the Public Staff to verify rate parity and compliance with the FCC's rules and that any further documentation is unnecessary.

REPLY COMMENTS

The Public Staff recommended, in regard to the NCTIA's first request for clarification, that the Commission set an effective date for the filing of tariffs and affidavits of no later than July 2, 2013. The Public Staff further stated that it had no objection to the NCTIA's second requested clarification.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

The Commission finds it appropriate to grant the Public Staff's Motion, however, with two clarifications:

(1) the effective date for the July 2013 annual revised intrastate switched access service tariffs and affidavits shall be no later than July 2, 2013; and

(2) ILECs not restructuring their intrastate switched access rates shall be permitted to provide a link to their interstate switched access tariff to show parity between ILEC intrastate and interstate switched access rates. ILECs restructuring only their terminating intrastate switched access rates shall be permitted to provide a link to their interstate switched access tariff rather than providing worksheets to show that intrastate rates equal interstate rates.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 20th day of May, 2013.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

bp052013.01

DOCKET NO. T-100, SUB 90

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Generic Docket to Investigate Several Concerns	)	ORDER RULING ON CERTAIN
Expressed by Outstanding Service Corp., d/b/a	)	INSURANCE ISSUES AND
John's Moving & Storage	)	REFERRING REMAINING ISSUES
	)	TO WORKING GROUP

BY THE COMMISSION: Docket No. T-100, Sub 90 is a generic docket that the Commission opened for the purpose of addressing certain issues that initially arose in Docket Nos. T-100, Sub 49 and Sub 69. In particular, in the Docket Nos. T-100, Sub 49 and Sub 69, on August 8, 2011, the Public Staff – North Carolina Utilities Commission (Public Staff) filed a motion to replace the informational booklet in the Commission's Maximum Rate Tariff No. 1 (MRT).

On October 5, 2011, the Commission issued an Order Requesting Comments regarding the Public Staff's August 8, 2011 motion. Initial comments were filed with the Commission on or before November 8, 2011 by the North Carolina Movers Association, Inc. (NCMA), and the following five Commission-certificated household goods (HHG) movers: City Transfer & Storage Co. (City Transfer); James G. Dunnagan, d/b/a Dunnagan's Moving & Storage (Dunnagan's Moving); Horne Moving Systems, Inc. (Horne Moving); Outstanding Service Corp., d/b/a John's Moving & Storage (John's Moving); and Johnson TV Service Center, Inc., d/b/a Steele & Vaughn Moving (Steele & Vaughn). Reply comments were filed with the Commission on November 29, 2011 by the Public Staff.

On May 30, 2012, the Commission issued its Order Amending Informational Booklet. On page 12 of that Order, the Commission stated:

> In regard to the other comments offered by John's Moving, aside from those addressed above, the Commission is of the opinion that these remaining matters which include the levels of cargo insurance, warehouse/storage-in-transit protections for the public, and proof of workers' compensation insurance, which is administered by the North Carolina Industrial Commission, are not matters currently under consideration by the Commission. Furthermore, although such matters may possibly be worthy of study, the Commission is of the opinion that these matters should not be considered in ruling on the Public Staff's motion. Consequently, the Commission finds that these other matters are beyond the scope of this proceeding.

Subsequently, in Docket No. T-100, Sub 90, on January 18, 2013, the Commission issued an Order Requesting Comments on the aforesaid John's Moving matters that were considered by the Commission to be beyond the scope of the aforesaid MRT informational booklet proceeding. The Commission sought comments on six issues, as set forth in its January 18, 2013 Order. Those six issues are set forth below; they are highlighted by italics and underlining. The Order also provided that such comments should include any information that the commenter believes is relevant to the Commission's consideration of these issues and any further related matters, including the prior comments filed on October 21, 2011 by John's Moving in Docket Nos. T-100, Sub 49 and 69, as set forth in the Appendix A, attached to the January 18, 2013 Order issued in Docket Nos. T-100, Sub 49 and Sub 69. That same Appendix A is also attached to this present Order as Appendix A for convenience of reference.

In the present docket, initial comments were filed with the Commission on or before February 15, 2013 by the Public Staff, the NCMA, Horne Moving, and Ray Moving and Storage Inc. (Ray Moving). Reply comments were filed with the Commission on March 7, 2013 by the NCMA. In addition, it is noted that Dunnagan's Moving also filed initial comments on February 18, 2013, but subsequently filed a request on February 26, 2013 seeking to withdraw its comments; and the only comments from John's Moving were those which had been filed on October 21, 2011 in Docket Nos. T-100, Sub 49 and 69 as referenced above.

ISSUE NO. 1 – DEPRECIATED VALUE PROTECTION (DVP)

In the comments presented in Appendix A, attached to this Order, John's Moving argued that the valuation option of DVP should be eliminated from the MRT because it is seldom used and because it confuses consumers and distracts them from the primary valuation options. As a result, the Commission requested comments on the following issue:

1. *The MRT provides for three types of valuation, which are Basic Value Protection (BVP), Depreciated Value Protection (DVP), and Full Value Protection (FVP). The type of valuation selected by a customer establishes the total value of a customer's shipment in case of catastrophic loss and also governs how the mover will resolve a customer's claim for loss of or damage to individual items.*

What are the advantages or disadvantages of offering DVP valuation? Describe the issues, if any, that HHG movers may have encountered settling claims under DVP protection? Generally, on an annual basis, what percentage of customers typically select (or default) to DVP valuation? Should DVP valuation continue to be available as an option for valuation? If not, what additional type of valuation, if any, should be adopted to replace it? In addition, since the DVP valuation is the current default valuation when a shipper fails to select a type of valuation, what should be established as the new default valuation protection, if DVP were to be eliminated from the MRT?

COMMENTS – ISSUE NO. 1

> **Ray Moving:** Whereas Depreciated Value Protection appears to be a viable option to offer consumers for valuation coverage, it is seldom misunderstood and rarely used. The consumer wants it with or without and nothing in between. Interstate moves dropped this option years ago with no backlash. The option that is offered now on interstate moves is deductibles on Full Value protection and this has been well received is extremely popular. By offering deductibles, the consumer benefits from full coverage and affordability.

Horne Moving: Depreciated Value Protection should be eliminated as it is seldom used. Military and Interstate shipments no longer offer this option. A better option for the consumer is Full Value protection with deductibles.

NCMA: Valuation is one of the most confusing aspects of the move process for both shippers and movers. Even though the NCUC mandates the use of the booklet Moving 101, shippers don't always read the booklet. Shippers operate under the presumption that the mover broke it, the mover has to fix it. However, when the shipper chooses a level of protection other than Full Value Protection [FVP], the mover has a lesser level of liability and does not have to repair or replace the item damaged.

Depreciated Value Protection is becoming extinct in the household goods shipments. The implementation is not understood well by both the public and the carriers. While the depreciation guide established by the American Moving and Storage Association is a good tool to use in settling depreciated claims, it does not take into consideration extraordinary wear and tear. The carriers don't know how to explain this type of coverage and very seldom do shippers request it.

The Surface Transportation Board [STB] (the federal government agency that deals with household goods valuation for consumer moves) eliminated Depreciated Value Protection in 2002. In 2012, they required movers to redesign the bills of lading to explain valuation in more detail. They have made full value protection the default level of protection. The shipper has to sign a waiver in order to receive $.60 per lb per article. The mover has to provide the shipper with the mover's maximum liability for $.60 per lb per article coverage. (For example, on a 10,000# shipment, the mover's maximum liability is $6,000). *See standard Uniform Household Goods Bill of Lading for interstate moves included.*

Carriers are also allowed to offer deductibles on the full value protection. This option allows the shipper to assume liability for part of their shipment, while having full value protection to protect them in case of larger amounts of damages. Movers traditionally offer $250 and $500 deductibles to their customers, along with the no deductible option. The STB requires the FVP be subject to a minimum of $6.00 per lb, as opposed to the $4.00 per lb that North Carolina requires. $4.00 per lb was enacted in North Carolina in 2001. The deductibles help keep the cost of FVP protection affordable to the shippers.

The Government Service Administration did away with DVP so long ago that we are unable to locate the exact date. FVP is required, with no deductibles. The Department of Defense did away with DVP in 2008 and made FVP the only level of protection that movers can offer. Of course, the government, not the shipper is paying for the protection on these types of shipments.

Depreciated Value Protection is a level of protection that has outlived its usefulness. It was developed to give consumers a choice besides Basic Valuation over 30 years ago. Full Value Protection with deductibles would serve the public much better.

Public Staff: DVP benefits shippers by offering them better coverage than Basic Value Protection (BVP) at a reasonable cost; it is especially beneficial to the shipper when the items being shipped are relatively new. The valuation revenue is a benefit to the carrier if the move is damage free but not if there is a claim. For example, assume that for a carrier to replace a two-year old, 100-pound sofa included in a 5,000-pound shipment with a similar one would cost the carrier $500. The *AMSA Joint Military/Industry Table of Weights and Depreciation Guide (AMSA Guide)* shows a depreciation schedule of 10% each of the first two years. The carrier's maximum liability in this instance under DVP would be $400 ($500 less $50 for 1st year and $50 for 2nd year). The shipper would have paid $31.50 (5,000lbs. x $1.25 = $6,250, rounded up to $6,300 x 50 cents per $100 of value).

Very few moves are performed under DVP. From 2006 to 2011, the percentage of moves performed under DVP averaged 2.81%, with a high of 3.67 % in 2010 and a low of 2.34% in 2006. However, determining the age of damaged or lost items can be difficult. Shippers do not always keep receipts or accurate information on the acquisition of items, which makes it difficult to accurately calculate reimbursement cost when using the *AMSA Guide*. Shippers may also have acquired the items as used rather than new.

Because DVP is the default valuation if the shipper does not select one, the shipper has to pay for this protection before any claims can be settled. This can be difficult for shippers to understand. The Public Staff has encountered DVP as the default only on rare occasions; most certificated carriers properly complete the paperwork.

DVP is not user friendly, not economically feasible for the carrier, and generally not the industry norm. Shippers moving under the strict guidelines of the military are no longer offered DVP, and the federal government does not offer it to shippers for interstate moves. To eliminate it as an option in North Carolina would be to conform to the moving industry practices elsewhere. A replacement default could be determined after weighing the positives and negatives of using Basic Value Protection or a form of Full Value Protection (FVP) with deductibles as a default.

NCMA's Reply: The NCMA agrees with the Public Staff that Full Value Protection with deductibles, along with the elimination of Depreciated Value Protection would better serve the public. We would be glad to work with the Commission to establish appropriate values and pricing for said coverage, if the Commission decides to change the valuation options.

DISCUSSION AND CONCLUSIONS – ISSUE NO. 1

Presently, the MRT requires that household goods movers/carriers offer shippers/customers/consumers three types of valuation. Customers are allowed to choose Basic Value Protection (BVP), Depreciated Value Protection (DVP), or Full Value Protection (FVP) valuation. None of these three types of valuation, including FVP, involve any deductibles. DVP valuation is the default valuation in the event a customer does not explicitly chose a valuation option.

The Commission's informational booklet, Moving 101 – A North Carolina Consumer's Guide, (Moving 101 Booklet), which the Commission requires movers to provide to all potential customers, describes the three types of valuation and pricing as follows:

> **Basic Value Protection - No Charge:** The mover's maximum liability will be 60¢ per pound based upon the weight of any lost or damaged items, regardless of its actual value. For example, damage to your refrigerator weighing 400 pounds would result in a maximum claim settlement of $240. Basic Value Protection provides minimal protection, and it is possible that settlement of any claim under this level of valuation will not be satisfactory to you. Under this type of valuation, for example, if the total weight of your shipment is 8,000 pounds, then the total value of your entire shipment is established to be $4,800.
>
> **Depreciated Value Protection - 50¢ Per $100 of Value:** The minimum value of the shipment will be $1.25 times the weight of the shipment. However, you have the right to declare that your shipment has a greater value and pay for that increased protection. When submitting a claim, you need to provide the replacement cost and the age of the lost or damaged items. You may ask your mover for the source of its depreciation rates. Many movers use the depreciation guide supplied by the American Moving and Storage Association. For example, damage to a seven-year old, $200 end table depreciated at a rate of 7% per year results in a depreciated value of $102. Movers have the options of paying you the depreciated value, repairing the item, or paying the repair cost. Under this type of valuation, for example, if the total weight of your shipment is 8,000 pounds, then the total value of your entire shipment is established to be $10,000 and the charge for that level of protection would be $50. However, if you decided that your shipment has a greater value, maybe $15,000 rather than the calculated minimum of $10,000, you could establish that your shipment value is $15,000 and the charge for that level of protection would be $75.
>
> **Full Value Protection - 75¢ per $100 of Value:** The minimum value of the shipment will be $4.00 times the weight of the shipment. However, you have the right to declare that your shipment has a greater value and pay for that increased protection. If items are lost, the mover will have the options of replacing them with articles of like kind and quality or paying the replacement cost as determined by current market value. If items are damaged, the mover will have the same options, plus the additional options of repairing the items or paying the repair

> cost. All damaged items that are either replaced or reimbursed at full-market value become the property of the mover. Under this type of valuation, for example, if the total weight of your shipment is 8,000 pounds, then the total value of your entire shipment is established to be $32,000 and the charge for that level of protection would be $240. However, if you decided that your shipment has a greater value, maybe $45,000 rather than the calculated minimum of $32,000, you could establish that your shipment value is $45,000 and the charge for that level of protection would be $337.50.

In this proceeding, the commenting parties are all of the opinion that the Commission should eliminate the DVP valuation option. The commenters observed that the household goods moving industry has moved away from DVP valuation and toward FVP valuation with deductibles. They recommended that the Commission adopt a FVP valuation option with deductibles. In particular, the NCMA proposed that the Commission adopt FVP valuation choices that would include the establishment of deductible options of $250, $500, or no deductible. The NCMA suggested that it be allowed to work with the Commission to develop appropriate values and pricing for FVP valuation if the Commission decides to change the present options for valuation.

The Commission understands that DVP is rarely used, in fact, as observed by the Public Staff from 2006 to 2011, the percentage of moves performed under DVP valuation averaged 2.81%. Further, the Commission recognizes that determining the costs and age of damaged or lost items can be difficult and subjective; the shipper needs to be able to provide the replacement cost and the age of the lost or damaged items, which may be difficult as shippers may not have receipts or other accurate tangible information that would adequately document the cost of such items and the date of original acquisition or it may be that such items were purchased used rather than new with little or no supporting documentation. Furthermore, the DVP has been eliminated by several federal government agencies as a valuation option, specifically, the General Service Administration, the Surface Transportation Board, and the Department of Defense have all stopped allowing DVP to be offered by movers as a valuation option.

Based upon the foregoing, the Commission is of the opinion that the DVP issue should be referred to the Public Staff, the NCMA, and other interested parties including any Commission-certificated household goods movers (collectively referenced as the Working Group) for analysis and the development of recommendations to be provided to the Commission for consideration. The Working Group is requested to:

(a) Develop a new FVP valuation option with appropriate deductible values and pricing;
(b) Determine a replacement default valuation option after weighing the pros and cons of using either BVP or the new FVP valuation option;
(c) Develop any necessary revisions in the MRT and the Moving 101 Booklet to reflect the Working Group’s changes to the valuation options; and
(d) Recommend the appropriate time period and/or date(s) for such proposed changes to be implemented.

The Commission is hereby requesting that the Public Staff organize, convene, and facilitate the activities/technical workshops of the Working Group, as needed, to address these matters and other issues addressed hereinafter, including any related issues, in order to develop and provide recommendations to the Commission. The Working Group should report its recommendations on these and other matters, as discussed elsewhere herein under Issue Nos. 2-4, to the Commission within 120 days after the issuance of this Order.

ISSUE NO. 2 – CARGO INSURANCE

In the comments presented in Appendix A, attached to this Order, John's Moving expressed concern over instances in which a customer establishes a total value of their shipment that is greater than the cargo insurance coverage for which the mover is insured. As a result, the Commission requested comments on the following issue:

2. *A Commission-certified HHG mover is required to have $50,000 of cargo insurance coverage for loss of or damage to a customer's shipment. In the event a customer selects a level of FVP valuation that exceeds the mover's current insurance coverage and its ability to pay if a total loss of customer's shipment should occur, should the mover be required to explicitly and directly inform customers of that fact? If so, what procedure should be implemented to allow a customer the opportunity to become fully informed prior to the move and prior to his/her selection of valuation protection?*

COMMENTS – ISSUE NO. 2

Ray Moving: If a shipment requires more than $50,000 coverage, the mover's insurance carrier can provide a rider for that particular shipment. This could be handled on a case by case basis and not increase mover's overhead which would have to be passed on to the consumer.

Horne Moving: Any moving company can obtain a rider from their carrier for any shipment that requires more than the $50,000 coverage. I understand that less than 8% of moves request full value and less than that request coverage of over $50,000. This would seem unnecessary based on those percentages.

NCMA: Movers need to be educated on how to handle this type of valuation request. It is discussed in the MRT seminar and the carriers are told to contact their insurance company to get a rider to give that specific shipper the additional coverage they have requested for his shipment. However, since less than 8% of the moves have full value protection and even less would declare over $50,000, this would be an unnecessary step to perform on a very small number of moves.

Public Staff: The Public Staff has not received any complaints or damage claims against certificated carriers in which inadequate cargo insurance was an issue. However, the Public Staff is aware of one instance in which a shipper had declared a value of $400,000 under FVP and the carrier only had the minimal

$50,000 coverage. The carrier was able to obtain a rider to her insurance policy to cover this particular move.

It may be appropriate for the industry to better educate its members about the potential cost to them personally and their businesses if they do not have enough cargo insurance. It may also be appropriate for the Commission to consider increasing the minimal level of required coverage, bearing in mind that cargo insurance is very expensive and increasing the level of coverage could be a barrier to obtaining a certificate of exemption.

The level of cargo insurance held by the carrier should not determine the type of valuation or the level of valuation selected by the shipper. It is the carrier's responsibility to obtain whatever additional cargo insurance may be selected by the shipper to serve his or her best interest. Requiring the carrier to provide a copy of a Certificate of Insurance (COI) showing the carrier's supporting insurance policies (i.e., cargo, vehicle or general liability) may be an option if requested by the shipper. The Public Staff understands that carriers are often required to provide such proof of insurance on commercial or office moves.

NCMA's Reply: The NCMA will be educating their membership on how they may have inadequate cargo insurance coverage for some valuation requests. However, not all certificated carriers are members of the NCMA and we have no way to educate them about their potential shortfall in coverage. Both the Commission and the Public Staff send out monthly notices to all carriers and would be better equipped to notify all carriers about this matter.

DISCUSSION AND CONCLUSIONS – ISSUE NO. 2

In selecting a valuation option the customer establishes: (1) the total value of their shipment; (2) how a mover will resolve their claim for loss or damage to individual items; and (3) how a mover will resolve their claim for catastrophic loss or damage to all of their items. Valuation is not insurance. Valuation is an agreement between a customer and a mover as to the total value of the customer's shipment. Insurance is an agreement between a mover and an insurance provider.

The Commission requires its certificated movers to have at least $50,000 of cargo insurance coverage for loss of or damage to a customer's shipment. At issue here is how to address instances in which a customer establishes a total valuation of their shipment to be greater than $50,000, or more generally, an amount greater than the mover's cargo insurance coverage.

Horne Moving and the NCMA observed that fewer than 8% of moves have FVP and even fewer than that involve moves where shippers request coverage or declare valuations that are in excess of $50,000 for the total value of their shipment. Both the NCMA and the Public Staff remarked that the household goods movers need to become better educated and informed to understand the potential cost to them in the event they do not have enough cargo insurance to cover the customer's valuation request. The Public Staff cautioned against the Commission increasing the minimum $50,000 cargo insurance coverage that movers are required to possess explaining that cargo insurance is expensive and that an increase in the required minimum insurance coverage could be a barrier for movers in obtaining a certificate of exemption to transport household goods. All of the commenters maintained that a mover can and should obtain additional cargo insurance, on a case-by-case basis, in the form of a rider to their insurance policy for any particular move when the customer establishes the total value of their shipment to be in excess of the mover's cargo insurance coverage.

Based upon the foregoing, the Commission finds and concludes that the storage issue should be referred to the aforesaid Working Group, as previously described herein, for analysis and the development of recommendations. The Working Group is requested to:

(a) Determine whether the Commission should maintain or change the current requirement that a mover have at least $50,000 of cargo insurance coverage at all times;
(b) Determine whether the Commission should adopt a new requirement that for any particular move, a mover must have cargo insurance coverage in at least an amount equal to the total value of the shipment as determined by the customer when the customer selects a valuation option;
(c) In the event that the Working Group agrees that a mover should be required to have cargo insurance coverage in an amount at least equal to the total value of the shipment, as determined by the customer when the customer selects a valuation option, determine whether the mover could pass through the cost of the additional insurance to the customer if a mover accordingly has to purchase additional cargo insurance for a particular move and, if so, how and to what extent could the mover do this, or if not, how and to what extent should the mover be allowed to do so;
(d) Develop any necessary revisions in the MRT and the Moving 101 Booklet, if required, to reflect the Working Group's proposed changes to the cargo insurance requirements; and
(e) Recommend the appropriate time period and/or date(s) for any such proposed changes to be implemented.

The Working Group should report its recommendations on these and other matters, as discussed elsewhere herein, to the Commission within 120 days after the issuance of this Order.

ISSUE NOS. 3 AND 4 – STORAGE

In the comments presented in Appendix A, attached to this Order, John's Moving expressed concerns about moving company warehouses where there is inadequate or no insurance coverage on the warehouse contents and about problems that may arise with the storage of customers' household goods in public self-storage facilities. As a result, the Commission requested comments on the following issues:

3. *Should the Commission require HHG movers to have insurance to cover the loss of or damage to a customer's property while stored in a warehouse? If so, what type of insurance and what amount of insurance coverage should be required? To what extent and how should the customer* *be informed of such coverage? Should the insurance coverage vary depending upon whether it is short-term storage-in-transit for a period of 180 days or less, or long-term (permanent) storage, more than 180 days? Are there other related issues which the Commission should consider?*

4. *Should HHG movers be required to routinely inform customers of the physical location and address for where their property is being stored? If so, how should the mover provide such information to the customer, i.e., what procedures should be implemented to keep the customer informed?*

COMMENTS – ISSUE NOS. 3 AND 4

Ray Moving: 3. Do all movers have warehouses for storage? This seems hard to enforce across the board if a mover doesn't have a warehouse and had to produce coverage on something it doesn't have.

4. A physical address for a consumer's storage whereabouts is a reasonable request and could be provided on the bill of lading and/or on the monthly storage bill.

Horne Moving: 3. Since all moving companies do not have warehouses or provide SIT, this would be hard to enforce.

4. Movers should provide a physical address of their company to the consumer. The consumer could visit that location if they need to. Warehouses are often not at the same physical address as the office.

NCMA: 3. Since the NCUC currently does not know which carriers have warehouses and perform SIT, the requirement to have insurance to cover property while stored in a warehouse would be hard for the Commission to enforce. While the Commission does ask for the location of the terminal where the mover is operating on the Certificate of Exemption application, the Commission does not ask if the mover has a warehouse and whether they will be offering storage. Also, the annual report does not break out storage revenue. The Commission presently does not regulate permanent storage at this time. Banks and/or landlords require that warehouses be insured.

4. HHGs movers should be required to let customer know their physical address of their company. Their address is already required on the bill of lading that they have given the customer.

Public Staff: ISSUES 3 AND 4. Household goods are stored as either storage-in-transit (SIT) or permanent storage. The Commission has jurisdiction over SIT but not permanent storage. Shipments held less than 180 days are considered SIT; once the 180 days have expired, the shipment converts to permanent storage. If a carrier brings a shipment into a warehouse knowing that the shipment will be there more than 180 days, the shipment is considered permanent storage from the outset.

The Public Staff believes that a carrier offering SIT should have control of the space in which the shipment will be stored. Currently, the MRT Rule 48(A) allows the holding of a shipment in the warehouse of the carrier or its agent, who may place shipments in public mini-storage facilities in its own name and receive the SIT revenues from the shipper. In such instances, the carrier would not have control over the physical environment in which the shipment is stored. To fully protect the shipper, the carrier should be required to have control over the warehousing where the shipment will be stored, either by ownership or by long-term lease, and to have warehouseman's insurance to compensate the shipper for any loss or damage while the shipment is in storage.

The MRT contains documents that carriers are required to give to shippers, such as billing documents, the brochure, details of valuation, and others. A form containing information regarding SIT may be useful to address questions relevant to SIT. The address of the warehouse and information regarding warehouseman's insurance could be included on that form.

The Commission may also wish to consider the rates for SIT. All SIT shipments are rated based upon weight and distance. If a shipment is transported into SIT from 35 miles or less, MRT Item 14 rates apply. Currently, that rate is $12.45 per cwt [for shipment weighing 4,000 to 7,999 pounds] If the same shipment is transported from 36 miles or greater, the rate in Section III applies, which is currently $29.65 per cwt [for distance of 36-50 miles], or more than twice as much. An analysis of the rates for SIT shipments may be appropriate.

NCMA's Reply: 3 and 4. The NCMA agrees with the Public Staff that a carrier offering SIT should have control of the space in which the shipment will be stored. We would have no objection to a form for carriers to give those shippers who require SIT, which would include the address of their warehouse. The NCMA also agrees with the Public Staff that an analysis of the rates for pick-up and delivery of SIT shipments would be appropriate.

DISCUSSION AND CONCLUSIONS – ISSUE NOS. 3 AND 4

Ray Moving, Horne Moving, and the NCMA commented that since all movers do not have warehouses or provide SIT, it would be difficult for the Commission to enforce a requirement that movers should have insurance to cover loss or damage to customers' possessions while such property is being stored.

The Public Staff explained that household goods are stored as either SIT or permanent storage; the Commission has jurisdiction over SIT but not permanent storage. Shipments held less than 180 days are considered SIT; once the 180 days have expired, the shipment converts to permanent storage. If a carrier brings a shipment into a warehouse knowing that the shipment will be there more than 180 days, the shipment is considered permanent storage from the outset. Currently, MRT Rule 48(A) provides that the SIT of shipments covered by the MRT is the holding of the shipment in the warehouse of the carrier or its agent for storage and the carrier may designate any warehouse to serve as its agent. The Public Staff observed that the carrier's agent may place shipments in public mini-storage facilities in its own name and receive the SIT revenues from the shipper. In such instances, the carrier would not have control over the physical environment in which the shipment is stored.

The Public Staff suggested that the Commission should change the present requirements of the MRT to require that carriers offering SIT should have control over the warehousing where the shipment will be stored, either by ownership or by long-term lease, and to have warehouseman's insurance to compensate the shipper for any loss or damage to customers' possessions while such shipment is in storage. The Public Staff also proposed the development of a document/form that the carrier should give to a customer who requires SIT that would provide useful information regarding SIT, including the specific warehouse storage address where the customer's shipment will be stored and information regarding the mover's insurance coverage for loss or damage to customer's possessions while such shipment is in storage. Lastly, the Public Staff remarked that an analysis of the rates for SIT shipments may be appropriate. However, the Public Staff did not offer any recommendations or suggestions on how the rates for SIT may need to be modified.

In its reply comments, the NCMA agreed with the Public Staff that a carrier offering SIT should have control of the space in which the shipment will be stored; that a document/form addressing storage of customers' shipments should be developed for carriers to give those shippers who require SIT; and that an analysis of the rates for pick-up and delivery of SIT shipments would be appropriate.

The Commission agrees with the Public Staff and the NCMA that the carrier offering SIT should have control of the space in which the shipment will be stored. Such control should be accomplished through the carrier's ownership of the facility or by long-term lease arrangement. Further, as recommended by the Public Staff, the Commission believes that it is appropriate to require the carrier to have warehouseman's insurance coverage in-force to compensate the customer for loss or damage that may occur while the shipment is in SIT status.

The Commission believes that it is in the best interest of both the mover and the customer, who requires the storage-in-transit of its shipment, to definitely be fully informed as to the type of storage facility, the physical location and address of the storage facility, and the mover's insurance coverage for loss or damage to customer's possessions while such shipment is in SIT status. As proposed by the Public Staff and the NCMA, the Commission agrees that a document/form should be provided to a customer who requires SIT that will present useful information regarding SIT, including the specific warehouse storage address where customer's shipment will be stored and information regarding the mover's insurance coverage for loss or damage to customer's possessions while such shipment is in storage.

As previously mentioned, the Public Staff has suggested that the SIT rates should be studied and the NCMA agreed that an analysis of the rates for pick-up and delivery of SIT shipments is appropriate; otherwise, they provided no other recommendations regarding rates.

Based upon the foregoing, the Commission finds and concludes that the storage issue should be referred to the aforesaid Working Group, as previously described herein, for analysis and the development of recommendations. The Working Group is requested to:

(a) Develop SIT shipment insurance requirements for when a customer's possessions are placed in a storage facility owned by the mover;
(b) Develop SIT shipment insurance requirements for when a customer's possessions are placed in a storage facility not owned by the mover (e.g., a public mini-storage facility);
(c) Determine, if the Commission were to adopt any such new SIT insurance requirements, whether the mover could/should pass through the cost of the additional insurance to the customer, and if so, how and to what extent could/should the mover do this;
(d) Develop an SIT information document/form for movers to complete and provide to customers who require SIT;
(e) Review and develop any necessary revisions in the MRT rates for pick-up and delivery of SIT shipments;
(f) Develop any other revisions in the MRT and the Moving 101 Booklet, if required, to reflect the Working Group's proposed changes to storage requirements; and
(g) Recommend the appropriate time period and/or date(s) for any such proposed changes to be implemented.

The Working Group should report its recommendations on these and other matters, as discussed elsewhere herein, to the Commission within 120 days after the issuance of this Order.

ISSUE NO. 5 – INSURANCE CERTIFICATES

In the comments presented in Appendix A, attached to this Order, John's Moving proposed that every time a mover provides an estimate to a customer, the Commission should require that the mover also provide to the customer a current certificate of insurance. John's Moving maintained that with such a requirement customers would be able to differentiate and distinguish between well-insured and not-so-well-insured movers. As a result, the Commission requested comments on the following issue:

5. *Should HHG movers be required to provide current insurance certificate(s) to customers with every estimate? Would this raise any confidentiality concerns or other issues?*

COMMENTS – ISSUE NO. 5

Ray Moving: Providing a certificate of insurance on every estimate seems a little unreasonable. First of all, it's an estimate and not a booked move and providing this would seem unnecessary when the move hasn't been booked yet. Secondly, a lot of movers provide estimates over the phone and this would be a difficult task to perform. If a consumer needs a certificate of insurance, they can request one from the mover.

Horne Moving: Movers should not be required to provide current insurance certificates for every estimate. This would be, in fact, impossible to do since not every estimate has to be written. Most movers are happy to provide one upon request from any consumer that books a move.

NCMA: HHG movers should not be required to provide current insurance certificates on every estimate. Written estimates are not mandatory for moves within North Carolina. The NCUC does a good job of keeping up with the required coverage for certified carriers. Since 60% of the moves performed (in 2009) did not have a written estimate done, this would be an onerous burden that does not benefit the majority of shippers. Certificates of Insurance are always provided for any shipper that requests them.

Public Staff: COIs are issued by insurance agents and show a "Certificate Holder," which is typically the person requesting the certificate. The COIs required by the Commission for applications and annual reports must show the Commission's information as the certificate holder to be accepted as proof of insurance. If a shipper wants a COI from the carrier, the carrier's insurance agent will have to supply it; the COI should show that particular shipper as the certificate holder. Because policies can lapse, a COI that is not issued contemporaneously with the move might not reflect current information. Carriers should be required to provide a copy of the COI showing cargo, vehicle, and general liability coverage at the shipper's request with the shipper as the certificate holder. As previously stated, carriers are often required to provide proof of insurance on commercial or office moves.

NCMA's Reply: The NCMA agrees with the Public Staff that Certificates of Insurance should be provided upon shipper's request only.

DISCUSSION AND CONCLUSIONS – ISSUE NO. 5

Ray Moving, Horne Moving, and the NCMA commented that they do not favor the Commission requiring movers to provide certificates of insurance to customers with every estimate. They argued that being required to provide certificates of insurance to customers with every estimate would be particularly burdensome when an estimate is provided by a mover to a customer via telephone rather than in writing. Further, the NCMA explained that written estimates are not mandatory for moves within North Carolina and observed that, in 2009, approximately 60% of the moves performed did not have a written estimate done. Ray Moving, Horne Moving, and the NCMA stated that movers readily provide customers with certificates of insurance upon request.

The Public Staff commented that movers should be required to provide a copy of a certificate of insurance showing cargo, vehicle, and general liability insurance coverage at the customer's request and with the customer being indicated as the certificate holder on the certificate of insurance. The NCMA agreed with the Public Staff that certificates of insurance should be provided only upon request by the customer.

The Commission understands that written estimates are not mandatory for moves within North Carolina; that quite often moves are performed with no written estimates as they were not requested; that an estimate for a move is not a booked move; and that quite often movers provide estimates over the phone, rather than in writing. Consequently, the Commission agrees with the commenters that movers should not be required to provide a certificate of insurance to customers with every estimate. The Commission also agrees that certificates of insurance, with all the types of insurance required by the Commission indicated, should only be required to be provided to a customer upon request by the customer if a move is booked.

The Public Staff also suggested that if a customer requests a certificate of insurance from a mover, then the mover should contact its insurance agent and request that a certificate of insurance be provided and that such certificate should indicate the specific customer as the certificate holder. The NCMA did not explicitly provide any reply comments on that aspect of the Public Staff's proposal. The Commission finds and concludes that if a customer requests a certificate of insurance from a mover then a certificate of insurance should be provided by the mover to a customer with the certificate indicating "Customer" as the certificate holder. However, a mover, if it chooses, may provide a customer a certificate of insurance that indicates the customer's specific name as the certificate holder; but, this should not be required.

ISSUE NO. 6 – WORKERS' COMPENSATION INSURANCE

In the comments presented in Appendix A, attached to this Order, John's Moving argued that that the Commission should require movers to have workers' compensation insurance. John's Moving asserted that with such a requirement customers would be protected if a moving company employee is injured on their property. As a result, the Commission requested comments on the following issue:

6. *Should HHG movers be required to provide verification to the Commission that they have workers' compensation insurance as required by the North Carolina Workers' Compensation Act, which is administered by the North Carolina Industrial Commission? If so, what procedures should be implemented to ensure that movers routinely provide updated information to the Commission? What level of oversight by the Utilities Commission is appropriate?*

COMMENTS – ISSUE NO. 6

> **Ray Moving:** Today's consumer is concerned primarily about cost and not coverage. How many consumers ask for proof of worker's comp coverage from landscapers, gutter cleaners, and tree cutters? Requiring for workers compensation coverage is a reasonable request, however it would difficult to require when smaller companies are not required to have this coverage.

Horne Moving: Movers should not be required to provide verification of worker's compensation coverage for every shipment. Most movers are happy to provide proof of this upon request from any consumer that books a move.

NCMA: Worker's Compensation coverage should be included in the Certificate of Insurance required on the annual report every year. While those companies who have three [*recte* two] or less employees are not required to have worker's compensation, the majority of the certificated carriers do not follow under that guideline. There could be a statement included in the annual report for those carriers to state that they are not required to have Worker's Compensation.

However, the Industrial Commission also states that "An employer is not relieved of its liability under the Act by calling its employees "independent contractors." Even if the employer refers to its workers as independent contractors and issues a Form 1099 for tax purposes, the Industrial Commission may still find that the workers were in fact employees, based upon its analysis of several factors, including but not limited to the degree of control exercised by the employer over the details of the work." Most employers think that just because they only pay by Form 1099 that they are exempt from worker's compensation. That is not always true. The State of North Carolina is starting to look hard at those individuals who receive their compensation on a Form 1099 and those companies that issue a large number of Form 1099.

On moves within North Carolina, homeowners are assuming liability for workers that they don't know they even have, if the moving company doesn't have worker's compensation insurance. If a moving company does not have worker's compensation and an employee gets injured at a shipper's house, the employee could file against the shipper's homeowner's policy for the damages incurred. This is an unfair liability to the shippers.

Proof of Worker's Compensation or a statement that the carrier is not required to have Worker's Compensation is a reasonable request and needs to be included on the annual report.

Public Staff: Workers' Compensation Insurance is required under G.S. 97-93 and G.S. 97-94; and penalties for failure to procure the necessary insurance may be accessed by the North Carolina Industrial Commission. Self-insurance is overseen by the North Carolina Department of Insurance. In addition, not all businesses are required to have workers' compensation, because it is based upon the number of employees. The definition of "employee" also can be problematic in the case of household goods movers. While it would be reassuring to have proof that carriers have the appropriate workers' compensation coverage in effect, Commission oversight in the form of a COI may require more knowledge and expertise than staff can provide. Other alternatives may be more appropriate.

> **NCMA's Reply:** The NCMA still feels that proof of Worker's Compensation on the Certificate of Insurance provided with the annual report or a statement that the carrier is not required to have Worker's Compensation is a reasonable request. We would be glad to comment on the other alternatives the Public Staff mentioned in their comments, if said alternatives were described.

DISCUSSION AND CONCLUSIONS – ISSUE NO. 6

Ray Moving stated that requiring workers' compensation coverage is a reasonable request. However, it observed that it would be difficult to require when there are small companies that are not required to have such coverage.

Horne Moving commented that movers should not be required to provide verification of workers' compensation coverage for every shipment, but it could be provided upon request to a shipper who books a move.

The NCMA commented that it favors the Commission requiring movers to include in their annual reports every year either proof that they have workers' compensation insurance or a statement explaining why they are not required to have such insurance. However, the NCMA did not offer any explanation or reason as to why it was of the opinion that such a requirement was necessary or what such a requirement could reasonably be expected to accomplish that was not now being accomplished by the NC Industrial Commission's administration, including enforcement, of the NC Workers' Compensation Act (Act).

The Public Staff cautioned that Commission oversight in the present regard may require more knowledge and expertise than the Public Staff can provide. The Public Staff further commented that other alternatives may be more appropriate, but the Public Staff did not provide any such alternatives.

In consideration of the foregoing and the entire information of record, the Commission is of the opinion that it should not require movers to include in their annual reports either proof that they have workers' compensation insurance or a statement explaining why they are not required to have such insurance.

The Commission has reached the foregoing conclusion, in large measure, based upon the fact (1) that the NC Industrial Commission is currently responsible for administering the Act, including enforcement, and no party has persuasively shown that such administration is deficient or otherwise in need of supplementation and/or duplication by the Commission and (2) that, if such a requirement were to be implemented, its administration would likely be a noteworthy undertaking requiring the allocation of significant Commission resources, including resources that, as indicated by the Public Staff, may not be (or are not) currently available to the Commission. Moreover, even if the necessary resources were, or were to become, available to the Commission, it is not at all clear to the Commission that the allocation of such resources to the present purpose would be warranted, as no party to the proceeding has identified any expected benefit to be derived from implementation of the instant requirement; that is, other than the Public Staff's having acknowledged that the verification in question would be "reassuring."

However, it does not appear to the Commission, all things considered, that such a benefit should be found compelling.

IT IS, THEREFORE, ORDERED as follows:

1. That the Public Staff, the NCMA, and other interested parties including any Commission-certificated household goods movers (collectively referenced as the Working Group) shall develop a new FVP valuation option and address the other matters outlined by the Commission in its conclusions concerning Issue No. 1 – DVP, as set forth elsewhere herein. The Working Group shall report its recommendations on these matters to the Commission within 120 days after the issuance date of this Order.

2. That the Working Group shall determine whether the Commission should maintain or change the current requirement that a mover have at least $50,000 of cargo insurance coverage and address the other matters outlined by the Commission in its conclusions concerning Issue No. 2 – cargo insurance, as set forth elsewhere herein. The Working Group shall report its recommendations on these matters to the Commission within 120 days after the issuance date of this Order.

3. That the Working Group shall develop SIT shipment insurance requirements and address the other matters outlined by the Commission in its conclusions concerning Issue Nos. 3 and 4 – storage, as set forth elsewhere herein. The Working Group shall report its recommendations on these matters to the Commission within 120 days after the issuance date of this Order.

4. That a certificate of insurance, with all the types of insurance required by the Commission indicated, and with "Customer" indicated as the certificate holder, is required to be provided by a mover to a customer upon request by the customer if the move is booked.

5. That copies of this Order shall be served by the Chief Clerk's Office to all Commission-certifcated household goods movers, the Public Staff, the NCMA, and the Attorney General.

ISSUED BY ORDER OF THE COMMISSION.
This the 31st day of December, 2013.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

APPENDIX A

The following quoted narrative is an excerpt from the comments filed on October 21, 2011 by Outstanding Service Corp., d/b/a John's Moving & Storage in Docket Nos. T-100, Sub 49 and 69:

> The value of HHG under DVP is quite subjective. One of the definitions for "depreciate" from Webster's is as an intransitive verb: "to fall in value". "Depreciate" can refer to a reduction in actual cash value, a reduction in "book value" as an accounting/taxation function along with other less relevant meanings. Many view the depreciated value of household goods to mean the actual cash value. What is the depreciated value of a used car? Consider that the IRS offers several different methods for depreciating a car for tax purposes; most people would consider the depreciated value of a car to mean actual cash value. AMSA's Depreciation Guide shows that upholstered furniture depreciates at 10% per year to a maximum of 75% depreciation. What if a 1 year old sofa is covered with cigarette burns and has been used regularly as a litter box by kitty before we ever move it? Is it still worth 90% of the replacement cost? Wouldn't its depreciated value be determined by the actual "fair market value" rather than the replacement cost reduced by an arbitrary percentage? Fair Market value is defined by The International Glossary of Business Valuation Standards as "The price, expressed in terms of cash equivalents, at which property would change hands between a hypothetical willing and able buyer and a hypothetical willing and able seller, acting at arm's length in an open and unrestricted market, when neither is under compulsion to buy or sell and when both have reasonable knowledge of the relevant facts."
>
> Also, consider the relationship between the required minimum coverage amounts for FVP and DVP. A shipper is only required to purchase 31% as much coverage under DVP compared to FVP ($4.00 X .31 = $1.25) at 1/3 less cost. Doesn't that seem to indicate that the authors of the MRT believe that used household goods are on average only worth 31% (or less considering the reduced cost of coverage) as much as new (replacement value) household goods? How is that reconciled with an end table losing 7% of its value each year? For this to make sense the average end table we move has to be 9.9 years old and the average sofa must be nearly fully depreciated.
>
> I was informed recently that only 3% of shippers in NC even choose DVP. I believe that DVP is a rarely used, subjective option that only serves to confuse consumers and distract them from the primary valuation options. I personally believe that it is an option that should be removed from the tariff.
>
> Finally, there are a few issues that I believe should be considered by the commission prior to any action on this brochure. In the name of educating

the consumer, full disclosure and mitigating the risks to the moving public, please consider the following scenarios:

1. A mover in NC is only required to have $50,000 cargo insurance. He can sell a shipper an unlimited amount of Full Value Protection. The consumer assumes that since it is a licensed mover following the rules for FVP that they are protected. A shipper chooses $400,000 FVP. Let's assume that the mover has no equity in their business. If the truck rolls into a ditch and catches on fire, the shipper gets $50,000 from the insurance company and an apology from the mover. The mover goes belly up. The shipper paid $3,000 for this coverage; 8 times the cost of the coverage the shipper *really* received. How is this not considered fraud?

2. A mover has 10 shipments in his warehouse, each with $40,000 FVP. The shippers are content knowing that they purchase valuation from a certificated NC mover. The mover has no insurance on the contents of his warehouse as it is not required by the NCUC. The building has an electrical fire over the weekend and burns to the ground (no requirement for fire suppression or fire alarms). All 10 families lose all of their worldly possessions and get $0.00 from the mover. No laws were broken; the mover files for bankruptcy and walks away from the situation.

3. A shipper learns of the licensing requirements in NC and seeks out and hires a certificated mover because of the perceived protection provided. As the movers carry the dresser down the stairs the man on the bottom slips and ends up in a heap at the bottom of the stairs with the dresser. His injuries are significant and he is permanently disabled. The moving company has no workers compensation insurance (although it is required, no one verifies it is in place) and goes out of business. The injured man's attorney sues the homeowner as the injury happened on their property.

4. A mover moves an unsuspecting shipper's property into "their" warehouse. In reality, it is a self storage unit the mover rented. The shipper is confident knowing that their property is with a certificated mover and assumes that it is on the movers premises. The mover starts falling behind on his bills. He stops paying the bill at the self storage unit. The self storage company sends auction notices to *the mover* (the only contact they have for the shipment). The mover fails to pay and the shipment is sold to the highest bidder at auction.

The public is under the false impression that when they hire a licensed mover, purchase FVP and/or move into "the mover's" storage facility that their interests are protected. It is a reasonable assumption on their part.

Many movers even refer to valuation as insurance; it is no wonder that the consumers are confused. The shipper has a right to know if there is anything to back up the amount of valuation they are purchasing or if it is just an empty promise.

It seems that at a minimum, movers should be required by the commission to provide a current insurance certificate to the shipper with every estimate. How is a shipper to differentiate between a well insured mover and one that is largely under insured/uninsured? The $100 savings in the estimate comes with a level of risk that would make even a hardened gambler cringe. How many movers tell the shipper “we’re fully insured”? Also, movers should be required to advise shippers of the physical location and address where their property is being stored. I believe that it’s only fair.

As a practical matter, I believe there should be some requirement (verified by the NCUC much the same as cargo insurance is) for proof of insurance for warehouse contents & workers compensation insurance. Additionally there should be a requirement for disclosure to the shipper when the level of FVP they select is well above the movers insurance and ability to pay in the event of a total loss.

DOCKET NO. E-7, SUB 1029

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Petition of Duke Energy Carolinas, LLC for an Accounting Order to Defer Certain Capital and Operating Costs Incurred for the Advanced Clean Coal Cliffside Unit 6 Steam Generating Plant, the Dan River Natural Gas Combined Cycle Generating Plant, and the Capacity-Related Modifications at the McGuire Nuclear Generating Plant	))))))))	ORDER APPROVING IN PART AND DENYING IN PART REQUEST FOR DEFERRAL ACCOUNTING

BY THE COMMISSION: On February 4, 2013, Duke Energy Carolinas, LLC (Duke, DEC, or the Company) filed a petition, in the above-captioned docket, requesting that the Commission issue an accounting order for regulatory accounting purposes authorizing the Company to defer in a regulatory asset account certain post-in-service costs being incurred in connection with (1) the Advanced Clean Coal Cliffside Unit 6 Steam Generating Plant (Cliffside), (2) the Dan River Natural Gas Combined Cycle Generating Plant (Dan River), and (3) the McGuire Unit 1 and Unit 2 capacity-related modifications (McGuire Uprates).

Duke further requested that the Commission enter an order approving this deferral request as soon as possible, but by no later than March 31, 2013, as the Company wishes to reflect the impact of the deferral in its quarterly financial reports for the first quarter of 2013.

On February 6, 2013, the Commission entered an Order Requesting Comments. Such Order required the Public Staff ─ North Carolina Utilities Commission (Public Staff) and permitted other interested parties to submit comments regarding the petition by no later than February 28, 2013. Said Order also allowed all parties to file reply comments on or before March 7, 2013.

The Public Staff filed its comments on February 28, 2013. On March 7, 2013, Duke filed reply comments. No other comments or reply comments were filed.

DUKE'S PETITION

The costs that Duke is seeking to defer are the plant-related incremental cost of capital, the incremental depreciation expense, and the incremental non-fuel operation and maintenance (O&M) expenses that are being incurred from the in-service dates of the present plant additions and modifications to the time the annual costs of these facilities are reflected in electric rates. On a NC retail basis, the Company calculates the incremental cost of capital to be approximately $95 million, the incremental depreciation expense to be approximately $52 million, and the incremental non-fuel O&M expenses to be approximately $4 million. The following table shows such costs by plant addition.

DEFERRED COST (000s)

Incremental Cost:	**Cliffside Unit 6**	**Dan River CC**	**McGuire Uprates**	**Total**
Cost of Capital	**$45,016**	**$39,442**	**$10,964**	**$95,422**
Depreciation Expense	**37,514**	**11,618**	**2,751**	**51,883**
Non-fuel O&M expenses	**3,383**	**534**	**0**	**3,917**
Total Deferred Cost	**$85,913**	**$51,594**	**$13,715**	**$151,222**

According to Duke, these incremental costs

> . . . will be submitted as a cost component of electric rates in the Company's upcoming rate case in Docket No. E-7, Sub 1026 (the "2013 Rate Case"), which the Company is filing contemporaneously with this deferred cost petition. The Company has calculated the estimates above assuming new rates reflecting the ongoing annual costs of these additions as effective October 1, 2013. The deferred costs above include estimates of the costs to be included in plant in-service. The deferred costs to be recorded on the Company's accounting records will be based on actual costs and the effective date of rates stemming from the Commission's Order in Docket No. E-7, Sub 1026.
>
> In the 2013 Rate Case, the Company is seeking an increase in its electric base rates to reflect, among other things, the cost of capital on the capital expenditures, depreciation expense, property taxes and the annual incremental operating and maintenance expenses ("O&M") costs [sic] of Cliffside, Dan River and the McGuire Uprates. That application also includes a levelized amount to amortize and recover over a period of five years, the costs deferred related to this Petition and accumulated in the regulatory asset account.

Duke commented that the unrecovered plant cost of these assets is approximately $1.7 billion on a total-company basis and $1.2 billion on a NC retail basis. As indicated above, the potential adverse impact to the Company's NC retail earnings associated with these asset additions, absent deferral, is approximately $151 million. In terms of return on equity (ROE), such amount equates to approximately 170 basis points. Therefore, according to Duke, the Company will suffer a material decline in its 2013 earnings unless the Company is permitted to defer all of the costs associated with the additions of Cliffside, Dan River, and the McGuire Uprates.

According to Duke,

> [t]he capital cost of Cliffside is approximately $1.9 billion ($1.3 billion on a North Carolina retail basis). The total costs associated with Cliffside to be deferred is based on its in-service date of December 30, 2012, through the date the capital costs of Cliffside and the incremental operating costs of Cliffside are

reflected in base rates. The capital costs of Cliffside to be deferred, however, are reduced since current rates already reflect recovery of the annual capital cost on approximately $716 million of the North Carolina retail portion of the cost to build Cliffside . . . .

The capital cost of Dan River is estimated to be approximately $673 million ($469 million on a North Carolina retail basis). The total costs associated with Dan River to be deferred is based on the date Dan River was placed in service on December 10, 2012 through the date the capital costs of Dan River and the operating costs of Dan River are reflected in base rates . . . .

[The Company] has incurred significant capital costs on [sic] modifying both Units of the McGuire Nuclear Generating Plant in order to increase the maximum net dependable capability (“MNDC”) of the McGuire Nuclear Plant. The total project costs related to this deferred cost petition is $194 million ($135 million on a North Carolina retail basis). The project costs related to McGuire Unit 2 were placed in service after the McGuire Unit 2 re-refueling outage in the fall of 2012. The project costs related to McGuire Unit 1 are to be placed in service after the McGuire Unit 1 re-fueling outage in the spring of 2013.

The Company explained that the McGuire refurbishments were composed of three projects,

McGuire Nuclear Station [MNS] Unit 1 & Unit 2 High Pressure [HP] Turbine Performance Upgrade: This project will replace the existing HP Turbine components with Siemens’ upgraded HP Turbine technology. With the HP Turbine performance upgrades in place, Siemens’ guaranteed output increase is 11.1 MWe/unit with an expected increase of 12.8 MWe/unit. The maximum estimated output increase per unit is 14.0 MWe.

McGuire Nuclear Station Unit 1 and 2 Measurement Uncertainty Recapture (“MUR”) Power Uprate: This uprate is associated with the Nuclear Regulatory Commission’s (“NRC”) final rule in the Federal Register (65 FR 34913), which modified Appendix K to NRC regulations related to core thermal power and permissible assumptions for performing loss of cooling and emergency core cooling system analyses. The primary benefit of this regulatory change is the ability to implement a power uprate, thereby increasing power generation capacity. The Appendix K power uprate is also identified as MUR Power Uprate. This uprate will allow an increase in thermal power of approximately 1.7 percent. [Footnote omitted.]

McGuire Nuclear Station Unit 2 – Main Generators Stator Refurbishment Project: The Main Generators for both MNS Units have several material condition issues related to the normal aging of this equipment. Refurbishment of the Main Generator stators will restore nameplate capability - - an uprate to current capability. The deferred cost the Company is seeking in this petition is only the

> cost related to the capital cost of the main generator stator for Unit 2 at McGuire, which was placed in service after the fall 2012 re-fueling outage. The main generator stator for Unit 1 at McGuire will be replaced in the fall 2014 re-fueling outage.

[Paragraph Nos. are excluded from quotations throughout this document.]

Duke observed that, in its 2013 Rate Case, it is proposing to recover the deferred costs over a multi-year period, which would mitigate the ultimate rate impact of this deferral, if approved by the Commission.

Additionally, the Company commented that

> [t]he Commission has allowed the Company to defer the depreciation and operating costs of the facilities described herein in its *Order Approving Settlement Agreement and Closing Investigation* in Docket No. E-7, Sub 1017, dated December 12, 2012 ("Investigation Order"). The Company has provided this Application to request all of the costs ─ including cost of capital ─ be approved for deferral.

The Company argued that approval of this deferral request would also be consistent with prior precedent, particularly with respect to Commission decisions in Docket No. E-7, Subs 487 and 999. Regarding Sub 999, Duke pointed out that the detrimental impact to the Company's ROE, had the Commission not allowed the deferral, would have been 29 basis points; whereas, in this instance, the detrimental impact of not receiving approval would be approximately 170 basis points.

In conclusion, the Company stated that

> [t]he outstanding capital investment in Cliffside, Dan River and the significant capacity-related modifications at the McGuire Nuclear Station of over $1.7 billion is financially significant and constitutes an extraordinary item of cost. Therefore, authorizing deferral of all of the incremental costs relating to placing in service the Cliffside and Dan River generating plants and the significant capacity-related modifications at the McGuire Nuclear Generating Plant are important to the maintenance of the Company's credit quality and financial integrity and will avoid a significant deterioration in its 2013 level of earnings. Commission approval to defer these costs is appropriate, reasonable, and consistent with prior Commission action.

PUBLIC STAFF'S COMMENTS

According to the Public Staff, in response to a Public Staff data request, Duke indicated, among other things, that the MUR project for both McGuire units is now estimated to be completed no earlier than September 2013, and therefore is no longer part of the deferral request.

The Public Staff commented that

DEC asserts that it is authorized to defer the depreciation and operating costs of the facilities described in the Petition pursuant to the Commission's December 12, 2012, *Order Approving Settlement Agreement and Closing Investigation* in Docket No. E-7, Sub 1017 (*Sub 1017 Order*),[1] and that it has filed the Petition to request that all costs – including capital costs – be approved for deferral. DEC further asserts that the requested deferral is consistent with prior deferrals approved by the Commission, including the deferral of post-in-service costs related to the Buck Natural Gas Combined Cycle Generating Plant (Buck) and the Bridgewater Hydro Generating Plant (Bridgewater) in Docket No. E-7, Sub 999, except that the basis point impact on ROE of the deferral requested in the Petition is even greater than the 29 basis point impact of the Buck and Bridgewater deferrals. Thus, it appears to the Public Staff that to be allowed pursuant to the *Sub 1017 Order*, the costs to be deferred must be related to "new generation" and they must be either depreciation or O&M costs. Otherwise, the deferral request must be evaluated under the principles the Commission has historically applied to such requests.

[Footnotes in quotes throughout this document have been renumbered to accommodate sequential numbering.]

As stated by the Commission in Duke Energy Carolinas, LLC, 99 N.C.U.C. 204, 226, Docket No. E-7, Sub 874 (2009),

> Such [deferral] requests, by necessity, have been considered on a case-by-case basis; and have been approved only in those instances where there was a clear and convincing showing that the costs in question were of an unusual and/or extraordinary nature and that, absent deferral, would have a material impact on the company's financial condition.

The costs DEC seeks to defer related to Cliffside 6 and Dan River unquestionably fall into this category. Moreover, prior to entering into the Settlement Agreement in Docket No. E-7, Sub 1017, the Public Staff made a commitment to DEC that it would not oppose the deferral of incremental capital costs, depreciation expense,

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[1] The pertinent language from the *Sub 1017 Order* reads:

> Duke will defer filing a general rate case by Duke Energy Carolinas, LLC (DEC), in North Carolina until February 2013, with the understanding that DEC will be allowed to defer the depreciation and operating costs of new generation incurred from the commercial operation of such new generation until the effective date of new base rates.

> and O&M costs related to Cliffside 6 and Dan River.[1] For these reasons, the Public Staff recommends that the Petition be granted as to all of the costs related to Cliffside 6 and Dan River for which deferral accounting is requested.

With regard to deferral of costs related to the McGuire Uprates, the Public Staff argued that

> the modifications described in the Petition that increase the MNDC of the McGuire Units 1 and 2 do not appear to be the kind of new generation that is normally the subject of deferral requests – for instance, Buck, Bridgewater, Cliffside 6, and Dan River – and to which they are being equated in the Petition. In recent years, power uprates have become a relatively common strategy used by utilities to increase the power levels of their nuclear plants,[2] but that does not make them new generating plants. Moreover, the Unit 2 generator stator refurbishment, which accounts for the bulk of the costs related to the McGuire Uprates, will only restore the nameplate capability of the unit. Indeed, at page 12, lines 20-22 of his prefiled direct testimony in Docket No. E-7, Sub 1026, Company witness Jamil states regarding the stator refurbishment: "This effort addressed normal operation degradation of critical components and eliminated the risk of end-of-life equipment failure ensuring continued reliability of operation." Unless the Commission determines that these uprates constitute new generation as contemplated in the *Sub 1017 Order*, this portion of the deferral request must be evaluated independently. Even if the Commission determines that the uprates are new generation, the *Sub 1017 Order* would apply only to depreciation.

According to the Public Staff, if deferral accounting treatment is not authorized for the cost of capital and depreciation expense related to each of the McGuire uprate projects, the impacts on DEC's ROE would be as follows:[3]

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[1] The Public Staff also committed not to oppose the extension of the Buck and Bridgewater deferrals until the date the Company is authorized to begin reflecting costs related to those plants in rates established in its then upcoming general rate case. The June 20, 2012, *Order Approving Deferral Accounting* in Docket No. E-7, Sub 999, provides that the deferrals will cease on the date the Company is authorized to begin reflecting the costs in rates or June 30, 2013, whichever is earlier.

[2] According to a June 15, 2012, Status Report on Power Uprates prepared by the NRC staff, four power uprates [have been approved] since May 25, 2011, including an MUR uprate at Shearon Harris Unit 1. The staff's May 25, 2011, Status Report on Power Uprates stated that the NRC had approved 10 plant-specific uprates since the previous update and that the staff was currently reviewing 11 uprates and expected licensees to submit an additional 34 uprate applications over the next five years. According to the Report, of the ten uprates approved between May 2010 and May 2011, eight were MUR uprates and two were extended power uprates or EPUs. EPUs usually require major equipment modifications such as the turbine and stator replacements that are the subject of the Petition in this docket. Status Reports on Power Uprates can be accessed at http://www.nrc.gov/reactors/operating/licensing/power-uprates.html.

[3] The basis-point impacts as presented by the Public Staff on a project-specific basis total 15 basis points; whereas, the basis points, as presented thereafter, on a disaggregated project-specific basis total 14.2 basis points. Presumably, the foregoing difference results from issues with rounding.

Generator Stator - Unit 2	10 basis points
HP Turbine - Unit 2	3 basis points
HP Turbine - Unit 1	2 basis points

The Public Staff calculated the basis point impacts of the cost of capital and depreciation components of the deferred costs for each of the projects to be as follows:

Generator Stator – Unit 2	Cost of Capital,	8 basis points
	Depreciation,	2 basis points
HP Turbine – Unit 2	Cost of Capital,	2 basis points
	Depreciation,	1 basis point
HP Turbine – Unit 1	Cost of Capital,	1 basis point
	Depreciation,	0.2 basis points

In consideration of the foregoing, the Public Staff argued that,

> [a]s shown above, the total ROE impact of the McGuire Uprates, absent deferral, is significantly less than the impacts of recent deferrals requested by DEC and authorized by the Commission, namely, costs associated with the Allen scrubbers and the acquisition of Saluda River EMC's interest in the Catawba Nuclear Station in Docket No. E-7, Sub 874 (estimated 67 and 47 basis points, respectively), and costs associated with the Cliffside scrubber in Docket No. E-7, Sub 866 (estimated 110 basis points). The 29 basis point total impact of the Buck and Bridgewater deferrals in Docket No. E-7, Sub 999, while considerably smaller, was almost twice . . . the earnings impact of the McGuire Uprates, absent deferral. Thus, the Public Staff believes the materiality of the impact of the McGuire Uprates on DEC's earnings, absent deferral, is highly questionable.

In concluding its argument, the Public Staff requested that the Commission consider the foregoing comments in its deliberations in this docket. However, the Public Staff did not take a definitive position, or make a definitive recommendation, as to whether or not the Commission should grant Duke's deferral request with respect to the McGuire Uprates.

DUKE'S REPLY COMMENTS

In its Reply Comments, Duke noted that the Public Staff had recommended that the Company's Petition be granted as to all of the costs related to Cliffside and Dan River for which deferral accounting had been requested, but that the Public Staff had questioned the appropriateness of the deferral of costs related to the McGuire Uprates.

Duke argued that

> [t]he Public Staff's argument misconstrues the language of the *Sub 1017 Order*. The *Sub 1017 Order* refers to the deferral of costs related to "new generation," which, contrary to the Public Staff's contention, is not limited to "new generating

plants." Because the modifications at the McGuire Nuclear Station have resulted in increased generating capacity at that facility, these power uprates constitute "new generation." The Public Staff has not referenced, and Duke Energy Carolinas has not been able to locate, any Commission precedent where the definition of "new generation" has been limited to the addition of a new plant or unit. In fact, the Commission's treatment of the McGuire Uprates is consistent with its treatment of the types of "new generation" that have historically been the subject of deferral requests. Here, Duke Energy Carolinas has included new generating capacity derived from uprates at its nuclear stations, including McGuire, as a cost-effective source of *incremental* capacity in each of its Integrated Resource Plans ("IRPs") filed with the Commission since 2008.[1] *See, e.g.*, Table 8.D on p. 98 of the Company's 2012 IRP, filed in Docket No. E-100, Sub 137. It reasonably follows that "new generation," as contemplated under the *Sub 1017 Order*, can be derived from modifications to an existing plant which results in increased generating capacity, as is the case with the McGuire Uprates.

Therefore, the McGuire Uprates constitute "new generation" and under the *Sub 1017 Order*, the Company is allowed to defer the depreciation costs associated with these projects.

Moreover, deferral of all costs related to the McGuire Uprates ─ including both depreciation and capital costs ─ should be allowed because it is consistent with Commission precedent.

Deferral requests have been considered by the Commission "on a case-by-case basis; and have been approved only in those instances where there was a clear and convincing showing that the costs in question were of an unusual and/or extraordinary nature and that, absent deferral, would have a material impact on the company's financial condition." *Order Approving Deferral Accounting*, issued March 31, 2009 in Docket No. E-7, Sub 874, at p. 25.

Duke commented that

[t]he Public Staff argues that "the materiality of the impact of the McGuire Uprates on DEC's earnings, absent deferral, is highly questionable." (Comments ¶ 9.) The Public Staff, does not directly oppose the Company's deferral request on this basis, but asks the Commission to consider the fact that the impact of the McGuire Uprates is "significantly less" than the impact of other recent deferrals approved by the Commission. (*Id.*)

The updated $170 million ($119 million on a North Carolina retail basis) capital investment in capacity-related modifications at the McGuire Nuclear Station is financially significant and constitutes an extraordinary item of cost.

[1] See IRPs filed in Docket No. E-100, Subs 118, 124, 128, and 137, respectively. The Company's 2012 biennial IRP remains pending before the Commission in Docket No. E-100, Sub 137, but each prior plan listed above, which included incremental nuclear capacity from uprates, has been approved as reasonable for planning.

Deferral of the incremental costs associated with this project is appropriate because the McGuire Uprates are "not a simple, regularly occurring, inconsequential event, but rather [are] a major, non-routine matter of considerable complexity and major significance." *Order Approving Deferral Accounting*, issued June 20, 2012 in Docket No. E-7, Sub 999, at p. 18.

Moreover, authorizing deferral of the incremental costs associated with the McGuire Uprates is important to the maintenance of the Company's credit quality and financial integrity. If the Commission does not approve deferral of the $12.4 million in costs related to the McGuire Uprates, the Company will experience a 14 basis point reduction to its earned ROE.

The Commission has expressly recognized the financial consequences the Company identifies in its Petition as valid criteria for deferral:

> in assessing the appropriateness of cost-deferral requests, the Commission has, historically, based its decision in large measure on the impact that the costs would have on the level of earnings currently being achieved by the company . . . current economic conditions; the Company's need for new investment capital; and the impact that the Commission's decision will have on the future availability and cost of such capital are also relevant to the appropriate resolution of matters of this nature. Additionally, whether the company has requested, or is contemplating requesting, a general rate increase and the timing, or the proposed timing, of the filing of such a request is also pertinent.

Order Approving Deferral Accounting with Conditions, issued March 31, 2009 in Docket No. E-7, Sub 874, at pp. 25-26. After setting out these criteria, the Commission applied them to the Company's Allen scrubber and Saluda acquisition deferral requests and found that the financial consequences and the fact that the Company was planning to file a rate case in the near term warranted deferral. *See id*. at p. 26.

Here, the Company has filed a general rate case that is currently pending in Docket No. E-7, Sub 1026. Furthermore, in its most recent earnings surveillance report filed with the Commission, Duke Energy Carolinas reported earnings less than the ROE approved by the Commission in the Company's last general rate case. Currently, the Company is under-earning, continues to experience further earnings erosion as new plant is added, and would experience an additional 14 basis point reduction to its earned ROE, if deferral accounting for the McGuire Uprates is not approved in this Docket. Therefore, authorizing deferral of incremental costs associated with the McGuire Uprates is essential to the maintenance of the Company's credit quality and financial integrity.

In conclusion, Duke asserted that the Company's request was reasonable and supported by Commission precedent.

DISCUSSION AND CONCLUSIONS

Duke has requested that the Commission issue an accounting order for regulatory accounting purposes authorizing the Company to defer in a regulatory asset account certain post-in-service costs being incurred in connection with Cliffside, Dan River, and the McGuire Uprates. The proposed deferral period is from the plant in-service dates to the time the annual costs of these plant additions and modifications are reflected in the Company's base rates in connection with its pending application for a general rate increase, in Docket No. E-7, Sub 1026.

The estimated deferred costs are based on in-service dates for Cliffside and Dan River of December 30, 2012, and December 10, 2012, respectively. With respect to McGuire, the HP turbine replacement at Unit 2 was placed into service after the Unit 2 fall 2012 refueling outage; the HP turbine replacement at Unit 1 is to be placed into service after the Unit 1 spring 2013 refueling outage; and the main generator stator for Unit 2 was placed in service after the fall 2012 refueling outage.

On a total-company basis, the total unrecovered plant costs are approximately $1.7 billion. Such costs on a NC retail basis are $1.2 billion

The plant-specific incremental costs, in the amount of $149.9 million on a NC retail basis, for which the Company is seeking deferral, are as follows: Cliffside ─ $85.9 million, Dan River ─ $51.6 million, and McGuire Uprates ─ $12.4 million.[1] According to the petition, should Duke's request not be approved, the detrimental impact to the Company's NC retail ROE would be approximately 170 basis points. Such detrimental impact would appear to become approximately 169 basis points after taking into account the effect of the McGuire MUR project having been eliminated from the Company's deferral request. (See Footnote No. 6.)

Cliffside and Dan River

Regarding Cliffside and Dan River, for reasons as explained hereinabove, Duke and the Public Staff have agreed that it would be appropriate for the Commission to approve the Company's deferral request with respect to the incremental costs associated with these plant facilities. The Commission, therefore, so finds and concludes.

[1] Regarding the MUR project for both McGuire units, the Public Staff, in its comments, stated that Duke had indicated that such modifications are now expected to be completed no earlier than September 2013, and, therefore, are no longer part of the deferral request. Although the Company has not amended its petition, per se, to explicitly reflect exclusion of the MUR project, its reply comments appear to corroborate the Public Staff's assertion, as the Company indicated therein that the NC retail cost it seeks to defer with respect to the McGuire Uprates is $12.4 million, and not the $13.7 million as originally requested.

McGuire Uprates

As indicated above, on a NC retail basis, the total McGuire plant-specific incremental costs, for which the Company is seeking deferral, is $12.4 million. According to the Public Staff ─ based upon information provided by Duke ─ such amount consists of approximately $2.5 million in depreciation expense, which equates to approximately three ROE basis points, and $9.9 million in cost of capital, which equates to approximately 11 ROE basis points.

The Public Staff did not take a position as to whether the McGuire deferral should be approved, but rather questioned the appropriateness of the Commission's doing so. In particular, the Public Staff argued that, under the Sub 1017 Order,[1] the costs to be deferred must be related to "new generation" and must be either depreciation or O&M costs, otherwise the deferral request must be evaluated under principles the Commission has historically applied to such requests.

In response, the Company commented that the Public Staff had not referenced, and Duke could not locate, any Commission precedent where the definition of "new generation" had been limited to the addition of a new plant or unit. Moreover, because the modifications at McGuire have resulted in increased generating capacity at that facility, Duke argued that such power uprates constitute "new generation." Duke further asserted that the Company has previously identified uprates of the present nature as a cost-effective source of incremental capacity in each of its Integrated Resource Plans filed with the Commission. Accordingly, Duke averred that, under the Sub 1017 Order, the Company is allowed to defer the depreciation expense associated with the McGuire projects.

For purposes of this proceeding, the Commission agrees with Duke that the increased capacity associated with the McGuire Uprates does, or at least should be construed to, represent "new capacity," under the Sub 1017 Order. Consequently, the Commission finds and concludes that Duke should be allowed to defer the $2.5 million in depreciation expense associated with the McGuire Uprates.

Duke further argued that deferral of all costs associated with the McGuire Uprates ─ including both depreciation and capital costs ─ should be allowed because to do so would be consistent with Commission precedent.

Regarding Commission precedent, it is undisputed that the appropriateness of deferral requests should be considered on a case-by-case basis, based upon the circumstances and/or events present in each instance. In determining whether to allow such requests, the Commission has consistently and appropriately based its decision on whether, absent deferral, the costs in question would have a material impact on the company's financial condition, and in particular, the company's achieved level of earnings. Also, as indicated above, current economic conditions, the impact that the Commission's decision will have on the future availability and cost of capital, the company's need for new capital, and whether the company has requested or is contemplating requesting a general rate increase and the timing, or the proposed timing, of the filing of such a request are also factors to be considered.

[1] Id. at Footnote No. 1.

Regarding the Commission's current-level-of-earnings criteria, according to the Company's 2012 fourth-quarter earnings surveillance report (NCUC ES-1 report) submitted to the Commission, Duke actually realized an ROE of 10.41%, for the 12-month period ending December 31, 2012. Such report also set forth the following supplementary information, or contained information from which the following information could be derived:

(a) If it had not been for unfavorable weather, Duke's 10.41% realized ROE would be increased by 64 basis points, on a pro forma basis, to 11.05%.

(b) If it had not been for "a one-time credit related to the rate case as a result of the re-establishment of regulatory assets related to Duke's Voluntary Opportunity Plan and pension costs . . ." [Emphasis added.] Duke's 10.41% realized ROE would be decreased by 78 basis points, on a pro forma basis, to 9.63%.

(c) Although not mentioned in the report in terms of basis-point impact, costs incurred to achieve the Duke/Cinergy and the Duke/PEC mergers decreased the level of earnings that would have otherwise been achieved, for the 12-month period ending December 31, 2012, by approximately 12 basis points and 93 basis points, respectively. Further, although not mentioned in the report, if it were to be assumed that the costs-to-achieve the Duke/PEC merger were an extraordinary nonrecurring one-time charge or that ratepayers should not be required to bear such costs without a clear and convincing showing by the Company that ratepayers had received a like amount of offsetting benefits, Duke's 10.41% realized ROE would be increased by up to 93 basis points,[1] on a pro forma basis, to 11.34%.

There is one additional matter of significance related to Duke's current level of earnings ─ or more specifically its 10.41% realized ROE for the 12-month period ending December 31, 2012 ─ that needs to be addressed. Such matter is discussed below.

On January 27, 2012, in Docket No. E-7, Sub 989, the Company was granted a general rate increase of approximately $309 million, on an annual basis. The rate increase was effective for service rendered on and after February 1, 2012. Therefore, it would appear that the full effect of the rate increase was not included in the Company's earnings for 2012. Assuming that the additional revenue from the rate increase would be realized uniformly on a month-to-month basis, it would appear that earnings associated with approximately one-twelfth of the $309 million rate increase were not included in the Company's realized ROE of 10.41%, for the 12-month period ending December 31, 2012.[2] The pro forma impact of including such earnings would be to increase the 10.41% realized ROE by 27 basis points, on a pro forma basis, to 10.68%.

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[1] This effect would be decreased, to some extent, by the impact of deferral and amortization of the costs-to-achieve, if determined to be appropriate.

[2] The foregoing would appear to be a conservative estimate, as the period for which the rate increase was not in effect ─ January 2012 ─ would appear to be a period when kWh sales are, typically, higher relative to certain other months.

Regarding Duke's current level of earnings, there is one final matter that is worthy of mention. Although the record is silent in the following regard, some portion of the McGuire costs for which the Company is now seeking deferral would appear to have been charged against income in 2012. Therefore, the 10.41% ROE actually realized by Duke, for the 12-month period ending December 31, 2012, has been reduced, to some extent, by costs that the Company now seeks, ex post facto, to defer and recover. Such amount would appear to be undeterminable from the record as it presently exists.

Regarding the matter of current economic conditions, the Commission is of the opinion that, for present purposes, such conditions have been appropriately incorporated into ─ and are revealed by ─ the cost of common equity capital or, stated alternatively, the ROE of 10.20% recently granted Virginia Electric and Power Company, *d/b/a* Dominion North Carolina Power (Dominion), in Docket No. E-22, Sub 479,[1] and by the 10.20% ROE agreed to by the Stipulating Parties, in Docket No. E-2, Sub 1023.[2]

Regarding Duke's assertion that approval of the McGuire-related deferral request was essential to the maintenance of the Company's credit quality and financial integrity, the Company offered no specific reason or objective factual analysis in support of its contention. The Commission, therefore, does not find the Company's argument persuasive, particularly in view of the Company's current jurisdictional financial standing, including the results of its operation for fiscal year 2012. Consequently, the Commission is of the opinion that this argument should be given only minimal weight for purposes of this proceeding.

Regarding other arguments offered by Duke in support of its request, which have not been specifically addressed above, the Commission does not consider such arguments to be significantly relevant and/or persuasive. Therefore, the Commission is of the opinion that those arguments too should be given only minimal weight for purposes of this proceeding.

As noted in the past, in fulfilling its responsibilities, the Commission has, historically, employed the use of deferral accounting sparingly, requiring instead that costs be charged against revenue realized during the accounting period in which the attendant costs were actually incurred. Importantly, deferral has been allowed only in those instances where there has been a clear and convincing showing that the costs in question, among other things, would have a materially detrimental impact on the company's financial condition, absent deferral.

In consideration of the foregoing, the Commission is of the opinion that the circumstances in this case do not warrant approval of the Company's deferral request with respect to the McGuire-related cost of capital in the amount of $9.9 million, as the Company has not clearly and convincingly shown that, absent deferral, it will suffer materially adverse consequences such that its financial condition would be significantly and inappropriately impaired.

[1] Order Granting General Rate Increase (December 12, 2012).

[2] Progress Energy Carolinas, Inc. (PEC), Application for a General Rate Increase, Agreement and Stipulation of Settlement, filed February 28, 2013.

The Commission, therefore, finds and concludes that Duke's deferral request with respect to the cost-of-capital component of the McGuire Uprates should be denied. In reaching this conclusion, the Commission has based its decision primarily upon

(1) The basis-point impact of the costs in question (11 basis points) relative to the Company's realized ROE (10.41%) for the 12-month period ending December 31, 2012;

(2) The fact that Duke's realized ROE for the 12-month period ending December 31, 2012 was 10.41%, even though the full amount of the rate increase granted in Docket No. E-7, Sub 989 was not included in the Company's earnings for that fiscal year;

(3) The fact that the ROE recently granted Dominion and that more recently agreed to by the Stipulating Parties ─ in the matter of PEC's pending application for a general rate increase ─ was 10.20%; and, consequently,

(4) The fact that Duke's realized ROE of 10.41% for fiscal year 2012 would appear to be robust and, arguably, in excess of its current cost of common equity capital, based upon the 10.20% ROE recently allowed and/or agreed upon, as referenced above.

SUMMARY OF CONCLUSIONS

In summary, concurrent with the filing of an application for a general rate increase, Duke, on February 4, 2013, in this docket ─ Sub 1029, filed a request for authority to defer costs of $151.2 million associated with plant facilities it had recently or would soon place in service (Cliffside, Dan River, and McGuire Uprates). Such amount was subsequently revised to $149.9 million. Duke and the Public Staff have agreed, and the Commission has concluded that $137.5 million of the deferral request ─ related to Cliffside and Dan River ─ should be approved.

The remainder of Duke's deferral request related to McGuire. As originally filed, that portion of the request was stated to be $13.7 million. Such amount was subsequently revised to $12.4 million. Of that amount, the Commission has concluded that deferral of depreciation expense in the amount of $2.5 million should be approved and that the $9.9 million cost-of-capital component of the McGuire-related deferral should be denied.

Therefore, with regard to the $149.9 million total deferral request, the Commission has concluded that $140 million should be approved or, stated alternatively, that $9.9 million should be denied.

IT IS, THEREFORE, ORDERED as follows:

1. That Duke's request to defer all incremental costs associated with the addition of Cliffside and Dan River and the incremental depreciation expense associated with the addition of the McGuire Uprates to utility plant in service is reasonable and appropriate and, therefore, as such, shall be, and is hereby, approved.

2. That the period of deferral shall be from the in-service dates of the present plant additions and modifications to the time the annual costs of such facilities are reflected in electric rates approved by the Commission in connection with Duke's pending application for a general rate increase, in Docket No. E-7, Sub 1026.

3. That this decision shall be, and is hereby, entered without prejudice as to the amount of the deferred costs to be allowed for ratemaking purposes, if such costs are included in future rate filings.

4. That Duke's deferral request with respect to the McGuire-related cost-of-capital component of such request, shall be, and is hereby, denied.

ISSUED BY ORDER OF THE COMMISSION.
This the 3rd day of April, 2013.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

Commissioner Bryan E. Beatty did not participate.

Dh032613.01

DOCKET NO. E-2, SUB 1031

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Duke Energy Progress, Inc. Pursuant to G.S. 62-133.2 and Commission Rule R8-55 Regarding Fuel and Fuel-Related Cost Adjustments for Electric Utilities	))))))	ORDER APPROVING FUEL CHARGE ADJUSTMENT

HEARD: Tuesday, September 17, 2013, at 9:30 a.m. in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman Edward S. Finley, Jr., Presiding, Commissioner Bryan E. Beatty, Commissioner Susan W. Rabon, Commissioner ToNola D. Brown-Bland, Commissioner Jerry C. Dockham and Commissioner James G. Patterson

APPEARANCES:

For Duke Energy Progress, Inc.:

Brian L. Franklin, Associate General Counsel, Duke Energy Corporation 550 South Tryon Street, DEC 45A/PO Box 1321, Charlotte, North Carolina 28201

and

Robert W. Kaylor, Esq., Law Office of Robert W. Kaylor, P.A., 353 Six Forks Road, Suite 260, Raleigh, North Carolina 27609

For the Using and Consuming Public:

Antoinette R. Wike, Chief Counsel, Public Staff, North Carolina Utilities Commission, 430 N. Salisbury Street, 4326 MSC, Raleigh, North Carolina 27699-4326

For North Carolina Sustainable Energy Association:

Michael Youth, Esq., 1111 Haynes Street, Suite 109, Raleigh, North Carolina 27604

BY THE COMMISSION: On June 12, 2013, Duke Energy Progress, Inc. ("Duke Energy Progress," "DEP," or the "Company"), filed an Application pursuant to G.S. 62-133.2 and Commission Rule R8-55 regarding fuel and fuel-related cost adjustments for electric utilities, along with the testimony and exhibits of Sharon S. Babcock, Sasha J. Weintraub, Joseph A. Miller, Jr., Regis T. Repko, and David C. Culp.

On June 14, 2013, Carolina Industrial Group for Fair Utility Rates II ("CIGFUR II") filed a petition to intervene. On June 18, 2013, North Carolina Sustainable Energy Association ("NCSEA") filed a petition to intervene. On June 28, 2013, Carolina Utility Customers Association, Inc. ("CUCA") filed a petition to intervene. These petitions to intervene were allowed in Orders dated June 24, 2013 and July 3, 2013.

On June 25, 2013, the Commission issued an Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice. That Order provided that the direct testimony of intervenors should be filed on August 30, 2013, that rebuttal testimony should be filed on September 11, 2013, and that a hearing on this matter would be conducted on September 17, 2013.

The intervention of the Public Staff is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

On August 29, 2013, the Public Staff filed a motion for extension of time to file testimony, and on August 30, 2013, the Commission granted the motion, extending the time for filing Public Staff and intervenor testimony to September 6, 2013, and for filing rebuttal testimony to September 13, 2013.

On September 3, 2013, DEP filed affidavits of publication indicating that public notice had been provided in accordance with the Commission's procedural order.

On September 6, 2013, the Company filed the supplemental testimony and revised and supplemental exhibits of Sharon S. Babcock. On that same date, the Public Staff filed the testimony of James G. Hoard and the affidavits of Randy T. Edwards, Kennie D. Ellis, and John R. Hinton. No other party filed testimony, exhibits, or affidavits.

On September 10, 2013, the Company filed a Motion for Witnesses to be Excused from Appearance at Evidentiary Hearing, and on September 13, 2013, the Commission issued an Order excusing the appearances of the Company's witnesses David C. Culp, Joseph A. Miller, Jr., and Regis T. Repko at the evidentiary hearing.

The case came on for hearing as scheduled on September 17, 2013. The prefiled testimony and affidavits and exhibits of DEP's and the Public Staff's witnesses were received into evidence. No other party presented witnesses, and no public witnesses appeared at the hearing.

On October 17, 2013, NCSEA filed a letter in lieu of a post hearing brief. In the letter, NCSEA stated that it did not challenge DEP's cost recovery application, but requested that the Commission incorporate into its order in this proceeding DEP's commitment to file an updated fuel procurement practices report by December 31, 2013, that includes its proposed natural gas hedging strategy.

On October 24, 2013, the Public Staff and DEP filed a motion requesting an extension of time to file briefs and proposed orders to November 1, 2013. On that same date, the Commission entered an Order granting the motion.

The Public Staff and DEP filed a joint proposed order on November 1, 2013.

Based upon the Company's verified Application, the testimony and exhibits received into evidence at the hearing, and the record as a whole, the Commission makes the following:

FINDINGS OF FACT AND CONCLUSIONS

1. Duke Energy Progress is a duly organized corporation existing under the laws of the State of North Carolina and is engaged in the business of developing, generating, transmitting, distributing, and selling electric power to the public in North Carolina, and is subject to the jurisdiction of the North Carolina Utilities Commission as a public utility. Duke Energy Progress is lawfully before this Commission based upon its Application filed pursuant to G.S. 62-133.2.

2. The test period for purposes of this proceeding is the 12 months ended March 31, 2013 ("test period").

3. In its Application and direct testimony, as revised in its supplemental testimony, DEP requested a total decrease of $42,520,348 to its North Carolina retail revenue requirement associated with fuel and fuel-related costs, excluding gross receipts tax and regulatory fee. The fuel cost factors requested by DEP included Experience Modification Factor ("EMF") riders that take into account fuel underrecoveries and overrecoveries experienced during the test period and the four months following the test period (April – July 2013), with an overall overrecovery of $10,922,481. Interest applicable to the $10,922,481 overrecovery was $2,547,974.

4. The Commission finds and concludes that the Company's baseload plants were managed prudently and efficiently so as to minimize fuel and fuel-related costs.

5. The Commission finds and concludes that the Company's fuel and reagent procurement and power purchasing practices during the test period were reasonable and prudent.

6. The Company's treatment of its share of the pre-merger fuel savings transferred to it from Duke Energy Carolinas, LLC ("DEC") reflects the amount contemplated in the Commission's Order in the DEC fuel cost recovery proceeding in Docket No. E-7, Sub 1033, is consistent with the treatment of post-merger fuel savings related to the merger of Duke Energy Corporation and Progress Energy, Inc., ("Merger"), and is thus reasonable and appropriate. In general, the validity of all Merger fuel-related savings shall remain subject to future Commission determination.

7. The test period per book system sales are 56,022,353 MWh. The test period per book system generation (net of station use and joint owner generation) and purchased power is 62,426,933 MWh and is categorized as follows:

Net Generation Type	MWh
Coal	18,901,576
Oil	82,809
Gas	11,564,664
Nuclear	24,523,041
Hydro – Conventional	661,976
Renewable Purchased Power	1,375,485
Other Purchased Power	5,317,382
Total Net Generation	62,426,933

8. The nuclear capacity factor appropriate for use in this proceeding is 95.7%.

9. The N.C. retail test period sales, adjusted for customer growth and weather, for use in calculating the EMF are 37,026,644 MWh. The adjusted N.C. retail customer class MWh sales are as follows:

N.C. Retail Customer Class	Adjusted MWh Sales
Residential	15,094,444
Small General Service	1,807,767
Medium General Service	10,866,330
Large General Service	8,812,849
Lighting	445,255
Total	37,026,644[1]

10. The projected billing period sales for use in this proceeding are 58,302,840 MWh on a system basis and 37,656,341 MWh on a N.C. retail basis. The projected billing period N.C. retail customer class MWh sales are as follows:

N.C. Retail Customer Class	Projected MWh Sales
Residential	15,450,381
Small General Service	1,927,403
Medium General Service	11,219,433
Large General Service	8,611,892
Lighting	447,233
Total	37,656,341[2]

11. The projected billing period system generation and purchased power for use in this proceeding in accordance with projected billing period system sales is 65,510,925 MWh and is categorized as follows:

[1] Rounding difference of 1.
[2] Rounding difference of 1.

Generation Type	MWh
Coal	11,186,528
Gas CT and CC	20,547,226
Nuclear	25,575,440
Hydro	629,565
Purchased Power	7,572,166
Total	65,510,925

12. The appropriate fuel and fuel-related prices and expenses for use in this proceeding are as follows:

A. The coal fuel price (including Joint Owners generation) is $38.995/MWh.
B. The gas CT and CC fuel price is $40.477/MWh.
C. The appropriate ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions (collectively, Reagents) expense is $43,471,831.
D. The total nuclear fuel price (including Joint Owners generation) is $7.591/MWh.
E. The total purchase power price (including the impact of JDA Savings Shared) is $40.152.
F. The adjustment to exclude the cost of mitigation sales is $(35,142,900).
G. Fuel expense recovered through intersystem sales is $(110,616,476).

13. The projected fuel costs for the North Carolina retail jurisdiction for use in this proceeding are $1,080,205,261. Consistent with G.S. 62-133.2(a2), the annual increase in the aggregate amount of fuel-related expenses associated with non-capacity purchased power costs, qualifying facility capacity costs, and renewable energy costs did not exceed two percent of DEP's total North Carolina jurisdictional gross revenues for 2012. In determining whether purchased power costs included in DEP's proposed rates should be limited pursuant to subsection (a2), DEP performed its evaluation excluding the costs directly related to joint dispatch agreement transactions between DEP and DEC, which are providing merger savings to DEP's North Carolina retail customers. The Commission finds that the exclusion of these costs from the calculation of the annual increase in the aggregate amount of fuel-related expenses associated with non-capacity purchased power costs is just and reasonable.

14. The Company's North Carolina retail jurisdictional fuel expense overcollection for purposes of the EMF was $10,922,481, including an overrecovery for the months of April 2012 to July 2013 of $2,400,151, and adjustments of: $6,314,340 related to renewable purchased power, $7,416 "all other fuel cost" allocator correction, $38,081 Kenansville adjustment, and $2,162,493 reclassification of shared pre-merger savings from the projected component of the rate to the EMF component. The EMF interest expense is $2,547,974. The Company's N.C. retail fuel and fuel-related expense over/(under)collection amounts were $(6,064,020) for the residential customer class, $599,965 for the small general service customer class, $3,884,867 for the medium general service class, $9,678,359 for the large general service customer class, and

$2,823,311 for the lighting customer class, for a total over collection of $10,922,481[1]. The related interest amounts for the customer classes are: $0 for the residential customer class, $89,995 for the small general service customer class, $582,730 for the medium general service customer class, $1,451,753 for the large general service customer class, and $423,496 for the lighting customer class.

15. Consistent with DEP's testimony, the decrease in customer class fuel and fuel-related cost factors from the amounts approved in Docket No. E-2, Sub 1018 should be allocated between the rate classes on a uniform percentage basis, using the uniform bill adjustment methodology that was approved by the Commission in Docket No. E-2, Sub 1018.

16. The appropriate prospective fuel cost factors for this proceeding for each of DEP's rate classes, excluding gross receipts tax ("GRT") and regulatory fee, are as follows: 2.822¢/kWh for the Residential class; 2.912¢/kWh for the Small General Service Class; 2.859¢/kWh for the Medium General Service class; 2.922¢/kWh for the Large General Service class; and 3.768¢ /kWh for the Lighting class.

17. The appropriate increment/(decrement) EMFs established in this proceeding, excluding GRT and the regulatory fee, are as follows: 0.040¢/kWh for the Residential class; (0.033)¢/kWh for the Small General Service class; (0.036)¢/kWh for the Medium General Service class; (0.110)¢/kWh for the Large General Service class; and (0.634)¢/kWh for the Lighting class.

18. The appropriate EMF interest decrements established in this proceeding, excluding GRT and the regulatory fee, are as follows: 0.000¢/kWh for the Residential class; (0.005)¢/kWh for the Small General Service class; (0.005)¢/kWh for the Medium General Service class; (0.016)¢/kWh for the Large General Service class; and (0.095)¢/kWh for the Lighting class.

19. The total net fuel and fuel-related costs factors for this proceeding for each of DEP's rate classes, excluding GRT and regulatory fee, are as follows: 2.862¢/kWh for the Residential class; 2.874¢/kWh for the Small General Service Class; 2.818¢/kWh for the Medium General Service class; 2.796¢/kWh for the Large General Service class; and 3.039¢ /kWh for the Lighting class.

20. The base fuel rate established in Docket E-2, Sub 1023 will be restated by the following cost amounts for each of DEP's rate classes, excluding GRT and regulatory fee: (0.014)¢/kWh for the Residential class; (0.015)¢/kWh for the Small General Service Class; (0.011)¢/kWh for the Medium General Service class; (0.009)¢/kWh for the Large General Service class; and (0.030)¢/kWh for the Lighting class. The restated base fuel factors, excluding GRT and regulatory fee are as follows: 3.016¢/kWh for the Residential class; 3.005¢/kWh for the Small General Service Class; 2.924¢/kWh for the Medium General Service class; 2.960¢/kWh for the Large General Service class; and 3.662¢/kWh for the Lighting class.

[1] Rounding difference of 1.

21. The non-fuel base rate established in Docket E-2, Sub 1023 will be adjusted by the following base rate riders for each of DEP's rate classes, excluding GRT and regulatory fee: 0.014 ¢/kWh for the Residential class; 0.015 ¢/kWh for the Small General Service Class; 0.011 ¢/kWh for the Medium General Service class; 0.009 ¢/kWh for the Large General Service class; and 0.030 ¢ /kWh for the Lighting class.

22. In its computation of fuel and fuel-related cost over- and under-collections in future monthly fuel reports, DEP shall reflect dead freight and similar coal transportation charges associated with plants that are no longer operating over a period of three months instead of reflecting the entire amount in the month in which the charges were incurred.

23. DEP shall evaluate its hedging strategy and file the results of the evaluation in conjunction with the filing of the proposed hedging strategy of DEC in Docket No. E-100, Sub 47A.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

This finding of fact is essentially informational, procedural, and jurisdictional in nature and is uncontroverted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

G.S. 62-133.2(c) sets out the verified, annualized information that each electric utility is required to furnish to the Commission in an annual fuel and fuel-related cost adjustment proceeding for a historical 12-month test period. In Commission Rule R8-55(b), the Commission has prescribed the 12 months ending March 31st as the test period for DEP. The Company's filing was based on the 12 months ended March 31, 2013. However, for purposes of calculating EMF billing factors, and as permitted by G.S. 62-133.2(d), the Company updated the test year to include the period April through July 2013 in its supplemental filing.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

The evidence for this finding of fact is found in the Application, the direct and supplemental testimony of Company witness Babcock, and the entire record in this proceeding. This finding and conclusion is not contested by any party.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The evidence for this finding of fact is found in the testimony of Company witnesses Repko and Miller, and the affidavit of Public Staff witness Ellis.

Commission Rule R8-55(d)(1) provides that capacity factors for nuclear production facilities will be normalized based generally on the national average for nuclear production facilities as reflected in the most recent North American Electric Reliability Corporation ("NERC") Generating Availability Report, adjusted to reflect the unique, inherent characteristics of the utility facilities and any unusual events. Company witness Repko testified that the

Company's four nuclear units, one unit at Harris Nuclear Station ("Harris"), one unit at Robinson Nuclear Station ("Robinson"), and two units at Brunswick Nuclear Station ("Brunswick"), operated at a system average capacity factor of 92.3% during the test period. This capacity factor exceeded the five-year industry weighted average capacity factor of 90.2% for the period 2007-2011 for average comparable units on a capacity-rated basis, as reported by NERC in its latest Generating Availability Report.

Company witness Repko testified that Brunswick Unit 2 set a 2012 annual net generation record of 7,987,810 MW hours ("MWh"), a mark which bests Brunswick's previous net generation record of 7,854,238 MWh, set in 2008. Harris completed a breaker-to-breaker run of 525 days leading into the spring refueling and maintenance outage that began on April 21, 2012, and marked a milestone in May 2012 with 25 years of reliable operation. The Company added approximately 50 MW of capacity during the spring 2012 refueling and maintenance outages at Harris and Robinson as part of a continuing uprate effort.

Witness Repko explained that DEP has realized measurable improvement with its efforts to maintain good nuclear generation performance. At Brunswick, for example, DEP's implemented emergency diesel generator improvements have reduced the unplanned unavailability by approximately 60%, and main steam improvements have reduced leakage and vulnerabilities that result in significant outage work. Additionally, work management efforts have lowered critical component maintenance backlogs to industry top quartile levels. Witness Repko also testified that Robinson achieved upward movement in the Institute of Nuclear Power Operations' performance index, moving from 4th quartile to the industry median, with the opportunity to improve further leading into the fall outage season. As of the filing of the Application, Robinson had operated continuously for over 430 days. Witness Repko testified that these examples represent improvements of both DEP's equipment and operator performance.

Witness Repko also stated that in general, refueling requirements, maintenance requirements, prudent maintenance practices, and NRC operating requirements impact the availability of DEP's nuclear system. Prior to a planned outage, DEP develops a detailed schedule for the outage and for major tasks to be performed including sub-schedules for particular activities. Additionally, witness Repko testified that DEP is very self-critical regarding each outage project and, using hindsight, identifies every potential cause of a forced or extended outage or incident and applies lessons learned to ensure continuous improvement.

Witness Repko testified that there was a refueling and maintenance outage underway on Brunswick Unit 1 leading into the test period that required just under a 20-day extension. The extension was most notably due to completing jet pump plug installation, tool failures with vessel visual inspection activities, and major rebuild work on the main steam isolation valves. Other major work completed during the Unit 1 outage at Brunswick included installation of an alternate decay heat removal system and significant electrical system reliability improvements, including switchyard and grid breaker, insulator, and relay upgrades.

Witness Repko also testified that the refueling and maintenance outage for Unit 1 at Harris began in April 2012 and required an additional day for nozzle repairs due to indications detected during the vessel head inspection performed within the outage. Activities completed also included replacement of the high pressure turbine, the main transformer, and the turbine lube oil cooler and piping.

Witness Repko further testified that Brunswick Unit 2 ended the test period during a refueling and maintenance outage that began in March 2013. He explained that key improvement activities included in the outage were replacement of the auxiliary transformer and two safety-related transformers, installation of an alternate decay heat system for spent fuel and decay heat removal, installation of a drywell camera for monitoring on-line leakage, and implementation of a variable frequency drive software upgrade to improve reliability.

Company witness Miller testified concerning the performance of DEP's fossil/hydro assets. He testified that the primary objective of the Company's fossil/hydro generation department is to safely provide reliable and cost-effective electricity to DEP's customers, and that it achieves this objective by focusing on a number of key areas. He stated that environmental compliance is a "first principle", and that DEP achieves compliance with all applicable environmental regulations and maintains station equipment and systems in a cost-effective manner to ensure reliability. The Company also takes action in a timely manner to implement work plans and projects that enhance the safety and performance of systems, equipment, and personnel, consistent with providing low-cost power for its customers.

Company witness Miller also testified that during the test period, the coal-fired units achieved a fleet-wide availability factor of 90.1% for the review period, and 97% during the 2012 summer peak months. He further testified that the hydroelectric fleet had outstanding operational performance during the test period, with a system availability factor of 97.7%. This availability measure is not affected by the manner in which the unit is dispatched, but is impacted by the amount of unit outage time. Additionally, witness Miller noted that the Company's large combustion turbine units were available as needed with a starting reliability of 99%.

Concerning significant planned outages occurring at the Company's fossil and hydroelectric facilities during the test period, Company witness Miller testified that in general, planned maintenance outages for all fossil and larger hydroelectric units are scheduled for the spring and fall to maximize the units' availability during periods of peak demand. During the test period, most of these units had at least one small planned outage to inspect and repair critical equipment or for the final tie-in of new environmental control equipment.

Public Staff witness Ellis testified that based on his review, it appears that DEP's proposed fuel and fuel-related cost factors and EMF, as revised in witness Babcock's supplemental testimony, are based on adjusted and reasonable costs that were prudently incurred under efficient management and economic operations.

Based upon the evidence in the record, the Commission concludes that DEP managed its baseload plants prudently and efficiently so as to minimize fuel and fuel-related costs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

Commission Rule R8-52(b) requires each electric utility to file a Fuel Procurement Practices Report at least once every 10 years and each time the utility's fuel procurement practices change. The Company's updated fuel procurement practices were filed with the Commission in Docket No. E-100, Sub 47A in June 2005, and were in effect throughout the 12 months ending March 31, 2013. In addition, the Company files monthly reports of its fuel and fuel-related costs pursuant to Commission Rule R8-52(a). Further evidence for this finding of fact is found in the testimony of Company witnesses Babcock, Weintraub, Miller, and Culp. Additionally, Public Staff witness Hinton addressed the Company's natural gas hedging strategy during the test period.

Company witness Babcock testified that DEP's fuel procurement strategies that mitigate volatility in supply costs are a key factor in DEP's ability to maintain lower fuel and fuel-related rates. Other key factors include DEP's diverse generating portfolio mix of nuclear, coal, natural gas, and hydro; lower natural gas prices; the capacity factors of its nuclear fleet; the combination of DEP's and DEC's respective skills in procuring, transporting, managing and blending fuels and procuring reagents; and the increased and broader purchasing ability of the combined Company as well as the joint dispatch of DEP's and DEC's generation resources.

Company witness Weintraub described DEP's fossil fuel procurement practices, set forth in Weintraub Exhibit 1. Those practices include computing near and long-term consumption forecasts, determining and designing inventory targets, inviting proposals from all qualified suppliers, awarding contracts based on the lowest evaluated offer, monitoring delivered coal volume and quality against contract commitments, and conducting short-term and spot purchases to supplement term supply.

According to witness Weintraub, the Company's average delivered coal cost per ton increased less than 1.0%, from $91.04 per ton from the prior test period to $91.36 per ton in the test period. The Company's transportation costs increased approximately 3.0%, from $27.94 per ton in the period test period to $28.77 per ton in the test period. He testified that coal markets continue to be in a state of flux due to a number of factors, including (1) recent U.S. Environmental Protection Agency regulations for power plants that result in utilities retiring or modifying plants, which lowers total domestic steam coal demand, and can result in some plants shifting coal sources to different basins; (2) continuing growth in global demand for both steam and metallurgical coal, which makes coal exports increasingly attractive to U.S. coal producers; (3) continued low gas prices combined with installation of new combined cycle generation by utilities, especially in the Southeast, which also lowers overall coal demand; and (4) increasingly stringent safety regulations for mining operations, which result in higher costs and lower productivity. Witness Weintraub stated that due to increasingly lower power prices, the retirement of DEP coal stations, and the addition of natural gas-fueled combined cycles, coal burn projections for 2013 and forward are forecasted to be lower than historical volumes. As an example of the impact, the actual coal burn for DEP's stations in 2012 was just over 9,700,000 tons, approximately 30% less than the average coal burn over the prior five-year period of over 12,400,000 tons. Based on the low coal burns in 2012, as well as the downward projection for coal burns in 2013 as compared to the amount of coal under contract for delivery in 2013, the Company expects coal inventories to be above target levels during 2013. According to witness Weintraub, if the Company experiences mild weather and continued low purchased power prices, there likely will be further upward pressure on coal inventories. He also testified that combining coal and transportation costs, DEP projects average delivered coal costs of approximately $92.85 per ton for the billing period.

Company witness Weintraub also testified that DEP continues to maintain a comprehensive coal procurement strategy that has proven successful over many years in limiting average annual coal price increases and maintaining average coal costs at or well below those seen in the marketplace. Aspects of this procurement strategy include having the appropriate mix of contract and spot purchases, staggering contract expirations which thereby limit exposure to market price changes, diversifying coal sourcing as economics warrant, and pursuing contract extension options that provide flexibility to extend terms within a particular price band.

The Company expects to address forward year coal requirements later this year with any potential competitively bid purchases, if made, taking into account projected coal burns, as well as coal inventory levels. The Company currently is considering alternatives to help mitigate inventory levels, including negotiating contract shipment deferrals/buy-outs and evaluating coal resell market opportunities. Due to lower coal demand for most of the U.S., however, either of these options would likely be difficult to achieve without paying additional costs to the supplier or incurring sales at potential losses.

Company witness Weintraub testified that the Company's natural gas consumption is expected to continue to increase. The Company consumed approximately 91 billion cubic feet ("Bcf") of natural gas in the test period, compared to approximately 72 Bcf in the prior test period. This increase was driven by the downward trend in the natural gas prices as well as the operation of the second combined cycle power block at the Richmond facilities. For the billing period, DEP's current forecasted natural gas consumption is approximately 158 Bcf. This forecast is based on current natural gas prices which are forecasted to remain low.

Witness Weintraub also testified that the development of shale gas has created a fundamental shift in the nation's natural gas market. Shale gas is natural gas that is trapped within shale formations, and which can provide an abundant source of petroleum and natural gas. Within recent years, improvements in production technologies have allowed greater access to the natural gas trapped in these formations, and has resulted in increased reserves that can produce natural gas supply more quickly and economically. Given continued production increases, natural gas prices continue to remain at lower levels. The Company's average price of gas purchased for the test period was $5.11 per Million British Thermal Units ("MMBtu"), compared to $5.49 per MMBtu during the prior test period.

Witness Weintraub testified that the Company has been executing a natural gas hedging strategy for the last several years in order to mitigate the price volatility of natural gas. The strategy incorporates a "dollar-cost averaging" approach of hedging that financially "locks-in" natural gas prices at a fixed price. Public Staff witness Hinton noted that the Company had requested recovery of $70 million from its North Carolina retail customers for the net cost of its natural gas hedging program, compared to $50 million requested in last year's fuel proceeding, Docket No. E-2, Sub 1018. While he believed that DEP's hedging activities were reasonable for the present proceeding, witness Hinton stated that he also believed the increase in sources of supply and reductions in price volatility since the 2010 fuel case warranted an additional reduction in the term structure of the Company's hedges from 24 months to 12 months as well as a reduction in the percentage of natural gas volumes hedged.

In response to questions from counsel for NCSEA, both witness Weintraub and witness Hinton agreed that entering into shorter term hedges of hedging fewer volumes when the Company's natural gas consumption is increasing would reduce costs to ratepayers in the short-term but increase their exposure to price increases in the future. Both witnesses, however, emphasized that the purpose of hedging is to mitigate or smooth out the effects of price volatility, and neither advocated entering into long-term hedges now when prices are at an all-time low because of speculation that prices may go up. Witness Hinton also emphasized that natural gas price volatility has decreased over time and continues to decrease. He explained that with the diversity of supply points for natural gas, particularly shale gas, there are fewer disruptions in supply and therefore fewer price spikes. In short, the landscape has changed and with it the trade-off between reducing costs to ratepayers and increasing exposure of ratepayers to price volatility.

Consistent with the Commission's Order in the 2013 DEC fuel case in Docket No. E-7, Sub 1033, Witness Weintraub recommended that the Commission evaluate DEP's hedging strategy when it is filed in Docket No. E-100, Sub 47A by the end of 2013.

G.S. 62-133.2(a1)(2) permits DEP to recover the cost of "ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions" (referred to by DEP's witnesses as "reagents"). Company witness Miller testified that DEP has installed pollution control equipment on coal-fired units in order to meet various current federal, state, and local reduction requirements for NO_x and SO_2 emissions. Each of these technologies requires the presence and consumption of specific chemicals which act as reagents in order for the chemical reactions to occur that greatly reduce the nitrogen oxide ("NO_x") or sulfur dioxide ("SO_2") emissions. The SCR technology that DEP currently operates uses ammonia or, in the case of Ashville, urea, which is converted to ammonia for NO_x removal, and the scrubber technology employed by DEP uses crushed limestone for SO_2 removal. Organic acid (often referred to as "DBA" or "dibasic acid") can also be used with the scrubber technology for additional SO_2 removal. In addition, DEP also uses magnesium hydroxide and calcium carbonate to mitigate increased sulfur trioxide ("SO_3") and reduce slag formation in the boiler, which if allowed to build, can significantly impair plant generation. This use of magnesium hydroxide and calcium carbonate allows DEP to meet increasing environmental standards and manage boiler slag formation in a cost efficient manner.

Company witness Miller further testified that DEP is testing the use of other emission-reducing chemicals, including, calcium bromide, activated carbon, and re-emission chemicals, in order to meet present and future state and federal emission requirements. New advancements in the environmental control arena provide DEP with new and improved emission-reducing chemical opportunities (such as the aforementioned chemicals) that it can use to comply with increasing federal and state environmental obligations. In order to meet these obligations in the least cost manner while continuing to provide reliable electric generation to its customers, DEP continually tests these new and improving emissions-reducing chemicals at its coal-fired plants with the hopes of eventually using them to more efficiently reduce emissions.

Company witness Miller testified that the Company's objectives in procuring emission-reducing chemicals and managing the resulting by-products are to provide the stations with the most effective total cost solution for operation of the unit, understand the technical capabilities of the equipment, assess emission-reducing chemical input and by-product output over the long-term, analyze the markets for those chemicals and by-products, and look for leverage opportunities with the chemical purchases and by-product sales contracts between stations and with other Duke Energy subsidiary operations.

Company witness Culp testified as to DEP's nuclear fuel procurement practices, which involve computing near and long-term consumption forecasts, establishing nuclear system inventory levels, projecting required annual fuel purchases, requesting proposals from qualified suppliers, negotiating a portfolio of spot and long-term contracts from diverse sources of supply, assessing spot market opportunities, and monitoring deliveries against contract commitments. Company witness Culp explained that for uranium concentrates as well as conversion and enrichment services, long-term contracts are used extensively in the industry to cover forward requirements and ensure security of supply. The typical initial delivery under new long-term contracts has grown to several years after contract execution because many proven, reliable producers have sold their near-term capacity. For this reason, DEP relies extensively on long-term contracts to cover the largest portion of its forward requirements. By staggering long-term contracts over time for these components of the nuclear fuel cycle, the Company's purchases within a given year consist of a blend of contract prices negotiated at many different periods in the markets, which has the effect of smoothing out the Company's exposure to price volatility. Diversifying fuel suppliers reduces the Company's exposure to possible disruptions from any single source of supply. Due to the technical complexities of changing fabrication services suppliers, DEP generally sources these services to a single domestic supplier on a plant-by-plant basis, using multi-year contracts.

G.S. 62-133.2(a1)(4), (5), (6) , and (7) permit the recovery of the cost of non-capacity power purchases subject to economic dispatch; capacity costs of power purchases associated with qualifying facilities subject to economic dispatch; certain costs associated with power purchases from renewable energy facilities; and the fuel costs of other power purchases. Company witness Weintraub testified that DEP and DEC consider the latest forecasted fuel prices, outages at the generating units based on planned maintenance and refueling schedules, forced outages at generating units based on historical trends, generating unit performance parameters, and expected market conditions associated with power purchases and off-system sales opportunities in order to determine the most economic and reliable means of serving their customers.

No other party presented or elicited testimony contesting the Company's fuel and reagent procurement and power purchasing practices. Based upon the fuel procurement practices report, the evidence in the record, and the absence of any direct testimony to the contrary, the Commission concludes that these practices were reasonable and prudent during the test period.

Consistent with the Commission's Order in the 2013 DEC fuel case in Docket No. E-7, Sub 1033 ("DEC Fuel Order"), the Commission concludes that DEP shall evaluate its natural gas hedging strategy in conjunction with evaluation of DEC's proposed hedging strategy and shall file a report in Docket No. E-100, Sub 47A by the end of 2013. The Commission further concludes that in this evaluation, DEP shall consider changes to the term and volume of hedges discussed in the testimony of witness Hinton.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence supporting this finding of fact and conclusion is contained in the testimony of Company witnesses Weintraub and Babcock and Public Staff witness Hoard.

Company witness Weintraub testified about the Joint Dispatch Agreement ("JDA"), which is an agreement between DEP and DEC where DEC acts as the Joint Dispatcher for DEC's and DEP's power supply resources. The JDA has allowed DEP's and DEC's generation resources to be dispatched as a single system to meet the two utilities' retail and firm wholesale customers' requirements at the lowest possible cost. As a result, the joint dispatch process allows DEP and DEC to serve their retail and wholesale native load customers more efficiently and economically than they can on a stand-alone basis.

Witness Weintraub testified that the JDA provides a methodology for calculating the savings generated by the joint dispatch process and for equitably allocating the savings between DEP and DEC. The joint dispatch savings automatically flow through to the Companies' retail customers through their fuel clauses. For native load wholesale customers, the joint dispatch savings are passed through as permitted by the applicable wholesale contracts. Under the joint dispatch process, the energy costs attributable to each utility's native load are the costs actually incurred by the utility for energy allocated to native load service, adjusted by the cost allocation payments calculated by the Joint Dispatcher, which are treated as purchases and sales between the Companies. As a result, the energy cost totals ultimately incurred by DEP and DEC to serve their respective native loads will be equal to the stand-alone costs they would have incurred but for the joint dispatch arrangement, less each utility's share of the joint dispatch savings.

In her supplemental testimony, Company witness Babcock explained that DEP made an adjustment to reflect interest on January 2012 to June 2012 pre-Merger savings in the EMFs. She stated that the pre-Merger savings adjustment to the EMF calculation in the DEC fuel case in Docket No. E-7, Sub 1033 puts DEC and its ratepayers in the position they would have been in if the Merger had closed in January 2012. A corresponding adjustment to the EMF calculation in the DEP fuel case puts DEP and its ratepayers in the position they would have been in if the Merger had closed in January 2012. Together, these adjustments put Duke Energy Corporation and the utilities' ratepayers in the same position they would have been in if the Merger had closed in January 2012.

Public Staff witness Hoard explained that pursuant to the Commission's June 29, 2012 Order, in Docket No. E-2, Sub 998 and E-7, Sub 986 (the "Merger Order"), the North Carolina retail customers of DEP and DEC (the "Utilities") have been guaranteed receipt of their allocable share of $686.8 million in fuel and fuel-related cost savings resulting from the Merger over a five-year period through the annual fuel charge proceedings of the Utilities. The five-year period may be extended by 18 months if ratepayers have not received their allocable share of the guaranteed savings at the end of the five-year period and the decline in natural gas prices has resulted in the delivery of less coal to certain DEC coal-fired plants. In addition, DEP and DEC are required to file monthly reports of tracked fuel savings with their Monthly Fuel Reports filed under Commission Rule R8-52. These reports of tracked fuel savings must show fuel savings broken down by the following categories: (a) total system, (b) DEP, (c) DEP North Carolina retail, (d) DEC, and (e) DEC North Carolina retail. If at the end of the guaranteed savings period the North Carolina retail customers of the Utilities have not received their allocable shares of the guaranteed fuel savings, the remaining amount shall be reflected as an adjustment in the first fuel cost proceedings of DEP and DEC following the end of the guaranteed savings period.

Witness Hoard provided the following Table 1 that shows details of the fuel savings through the end of the test period that have been reported by the Utilities:

TABLE 1

	DE Carolinas	DE Progress	Combined
Joint Dispatch	$ 14,124,150	$ 14,869,522	$ 28,993,672
Coal Blending	32,489,234	-	32,489,234
Coal Procurement	3,092,799	4,187,092	7,279,891
Coal Transportation	3,909,153	3,262,739	7,171,892
Reagent Procurement & Transportation	596,973	810,664	1,407,637
Natural Gas Capacity	11,006,008	-	11,006,008
Natural Gas Trading	323,586	-	323,586
	$ 65,541,903	**$ 23,130,017**	**$ 88,671,920**

The combined amounts shown in column (c) above are the sum of the savings that originated in each utility. These fuel savings are reflected in the actual expenses reported by the originating utility; the amount of the combined fuel savings is allocated between DEP and DEC each month based on the Utilities' relative MWh generation. As a result, an accounting entry has been recorded each month since the Merger closed to transfer savings that exceed the allocated share of the originating utility to the other utility. Witness Hoard also provided the following Table 2 that shows the amount of fuel savings that were transferred by DEC to DEP during the test period.

Table 2
Duke Energy
Progress

Item	Gross Amount	Allocated Share	Transferred
	(a)	(b)	(c)
Joint Dispatch	$ 14,869,522	$11,108,588	$3,760,934
Coal Blending	-	9,186,161	(9,186,161)
Coal Procurement	4,187,092	2,835,744	1,351,348
Coal Transportation	3,262,739	2,956,185	306,554
Reagent Procurement & Transportation	810,664	674,165	136,499
Natural Gas Capacity	-	4,181,230	(4,181,230)
Natural Gas Trading	-	126,754	(126,754)
	$ 23,130,017	**$ 31,068,826**	**$(7,938,809)**

The total amount shown in column (c) is the difference between the gross amount originating with DEP and its allocated share of combined savings. Witness Hoard explained that the Coal Blending, Coal Procurement, and Coal Transportation fuel savings amounts transferred between DEP and DEC are reflected in the Steam Generation section, Account 4560DEP, of Monthly Fuel Report Schedule 2, page 1 of 2. According to witness Hoard, all of the Coal Blending savings originate in DEC, because they result from the implementation of coal blending at the DEC coal-fired plants. DEP, which implemented coal blending at its coal-fired plants in 2006, already has considerable experience with coal blending. Because DEP fully implemented coal blending before the Merger, there are no Merger-related coal blending savings for the DEP coal-fired plants. DEC, however, began some coal blending activities at its Marshall Steam Plant prior to the Merger, so the Utilities have excluded a portion of these savings from the computation of Merger-related Coal Blending savings. The Coal Procurement and Coal Transportation savings result from renegotiated and new contracts that the Utilities have entered into with coal and coal transportation services providers, and thus savings originate in both Utilities.

Similarly, witness Hoard explained, the Reagent Procurement and Transportation savings amounts result from renegotiated and new contracts that the Utilities have entered into with reagent and reagent transportation services providers. The net Reagent Procurement and Transportation savings amount transferred to DEC of $136,499 is reflected as a credit to Account 50200PS – Reagent Procurement Merger Savings on Schedule 2, page 1 of 2, of the Monthly Fuel Report. All of the savings related to coal and reagent procurement and transportation reported through March 31, 2013, result from contract negotiations and renegotiations with fuel supply and transportation vendors that were premised upon the Merger, but undertaken by the Utilities prior to its closing.

Witness Hoard explained that the Natural Gas Supply and Capacity savings amount is composed of savings on purchases of gas supply, pipeline capacity costs, and purchases of oil.

Monthly Fuel Report Schedule 2, Account 05473200 reflects $4,181,230 for the transfer of savings from DEC to DEP.

Witness Hoard further explained that the Avoided Trading Desk savings amount is a non-fuel and fuel-related cost item that is reflected on the Monthly Fuel Report, Schedule 2, page 2 of 2, in Account 05472100. Due to the Merger, only one natural gas trading desk is needed by the Utilities. As a result, the Utilities have avoided the personnel and related costs for a second trading desk that would have been needed had the Utilities not merged. The Avoided Trading Desk savings have been counted towards the fuel savings guarantee, but do not flow through the fuel clause.

Witness Hoard testified that Company witness Babcock reflected an adjustment to her EMF computation for pre-Merger savings that DEC believes should be shared with DEP. DEC reflected the transfer of these savings from DEC to DEP in fuel and fuel-related expenses as part of its recent fuel case. The North Carolina retail amount of these savings, which total $2,162,493, is reflected on Babcock Revised Exhibit 3, pages 1 through 6, and increases the overcollection that Company witness Babcock has reflected in the EMF computation for the test period. The computation of this amount is shown on Babcock Workpaper 12.

Witness Hoard stated that both Utilities benefit from the Merger fuel-related savings, and the Company's proposal to share pre-Merger fuel savings between the two Utilities is consistent with the treatment of post-Merger fuel savings. In the DEC 2013 Fuel Order, the Commission approved DEC's proposal to share the pre-merger fuel savings with DEP, subject to the condition that DEP reflects the full offsetting amount in its upcoming fuel proceeding. Witness Hoard stated that the treatment proposed by DEP in this proceeding is consistent with the DEC 2013 Fuel Order.

Witness Hoard noted that the Public Staff has reviewed the tracked fuel savings computations but has not yet confirmed the validity of the amounts. He stated that the Public Staff will continue to review these fuel savings with due diligence. The Public Staff recommended that should the Commission approve adjustments to the cumulative amount of reported fuel savings in a future proceeding, the Commission should address the accounting and ratemaking treatment of the adjustments at that time.

Based on the evidence presented, the Commission finds and concludes that DEP's proposal to receive its share of pre-Merger fuel savings between itself and DEC is consistent with the treatment of post-Merger fuel savings related to the Merger and is thus reasonable and appropriate. In general, the cumulative amount of and accounting and ratemaking treatment of all Merger-related fuel and fuel-related cost savings shall remain subject to future Commission determination as described in the Merger Order.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence supporting this finding and conclusion is found in the testimony and exhibits of Company witness Babcock.

According to the exhibits sponsored by Company witness Babcock, the test period per book system sales were 56,022,353 MWh and test period per book system generation and purchased power was 62,426,933 MWh. The test period per book generation and purchased power is categorized as follows (Babcock Exhibit 6, Schedules 1, 3 and 5):

Net Generation Type	MWh
Coal	18,901,576
Oil	82,809
Gas	11,564,664
Nuclear	24,523,041
Hydro – Conventional	661,976
Renewable Purchased Power	1,375,485
Other Purchased Power	5,317,382
Total Net Generation	62,426,933

The evidence presented regarding the operation and performance of the Company's generation facilities is discussed in the Evidence and Conclusions for Finding of Fact No. 4.

No party took issue with the portions of witness Babcock's exhibits setting forth per books N.C. retail sales, generation by fuel type, and purchased power. Therefore, based on the evidence presented and noting the absence of evidence presented to the contrary, the Commission concludes that the per books levels of test period system sales of 56,022,353 MWh and system generation and purchase power of 62,426,933 MWh are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence supporting this finding of fact is found in the testimony and exhibits of Company witnesses Babcock and Repko, and the affidavit of Public Staff witnesses Ellis.

Commission Rule R8-55(d)(1) provides that capacity factors for nuclear production facilities will be normalized based generally on the national average for nuclear production facilities as reflected in the most recent NERC Generating Availability Report, adjusted to reflect the unique, inherent characteristics of the utility's facilities and any unusual events. The Company proposed using a 95.7% capacity factor in this proceeding based on the operational history of the Company's nuclear units, and the number of planned outage days scheduled during the 2013-2014 billing period. This proposed capacity factor exceeds the five-year industry weighted average capacity factor of 90.2% for the period 2007-2011 for average comparable units on a capacity-rated basis, as reported by NERC in its latest Generating Availability Report. Public Staff witness Ellis did not dispute the Company's proposed use of a 95.7% capacity factor.

Based upon the requirements of Commission Rule R8-55(d)(1), the historical and reasonably expected performance of the DEP system, and the fact that the Public Staff did not dispute the Company's proposed capacity factor, the Commission concludes that the 95.7%

nuclear capacity factor, and its associated generation of 25,575,440 MWh, are reasonable and appropriate for determining the appropriate fuel costs in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 9-11

The evidence supporting these findings of fact is found in the testimony and exhibits of Company witness Babcock, and the affidavits of Public Staff witnesses Ellis and Edwards. On Babcock Revised Exhibit 4, Company witness Babcock set forth the test year per books North Carolina retail sales of 36,857,232 MWh, comprised of Residential class sales of 14,971,380 MWh, Small General Service class sales of 1,800,189 MWh, Medium General Service class sales of 10,844,677 MWh, Large General Service class sales of 8,796,613 MWh, and Lighting class sales of 444,373 MWh. Witness Babcock made an increment adjustment to per book North Carolina retail sales of 106,211 MWh for customer growth and an increment adjustment of 63,202[1] MWh for weather normalization, broken down as follows:

N.C. Retail Customer Class	Customer Growth	Weather Normalization
Residential	69,562	53,501
Small General Service	6,197	1,381
Medium General Service	13,333	8,319
Large General Service	16,236	0
Lighting	883	0
Total	106,211	63,201

Based on these adjustments, witness Babcock calculated an adjusted test year N.C. retail sales level of 37,026,644 MWh (Babcock Revised Exhibit 4) for use in calculating the proposed EMF rates by customer class, broken down as follows and utilized as shown in Babcock Revised Exhibit 4:

N.C. Retail Customer Class	Adjusted MWh Sales
Residential	15,094,444[2]
Small General Service	1,807,767
Medium General Service	10,866,330[3]
Large General Service	8,812,849
Lighting	445,255[4]
Total	37,026,644[5]

Witness Babcock used projected billing period system sales, generation, and purchased power to calculate the proposed prospective component of the fuel rate. The projected system sales level used, as set forth on Babcock Revised Exhibit 2, Schedule 1, Page 1 is

[1] Rounding difference of 1.
[2] Rounding difference of 1.
[3] Rounding difference of 1.
[4] Rounding difference of 1.
[5] Rounding difference of 1.

58,302,840 MWh. The projected level of generation and purchased power used was 65,510,925 MWh (calculated using the 95.7% capacity factor found reasonable and appropriate above), and was broken down by witness Babcock as follows, as set forth on that same schedule:

Generation Type	MWh
Coal	11,186,528
Gas CT and CC	20,547,226
Nuclear	25,575,440
Hydro	629,565
Purchased Power	7,572,166
Total	65,510,925

Per Babcock Revised Exhibit 2, Schedule 1, Page 1, the difference of (7,208,084) MWh between projected billing period system generation and purchased power and projected billing period system sales consists of the adjustment to exclude mitigation sales of (922,000) MWh, fuel expenses recovered through intersystem sales of (3,139,037) MWh, and line losses and Company use of (3,147,047) MWh. The total projected system fuel and fuel-related expense derived in part from the use of these generation and purchased power amounts was utilized to calculate the prospective period fuel and fuel-related cost factors recommended by the Company and the Public Staff.

Company witness Babcock also presented the projected billing period N.C. retail Residential, Small General Service, Medium General Service, Large General Service, and Lighting MWh sales (Babcock Workpaper 4). The Company projects billing period North Carolina retail MWh sales to be as follows:

N.C. Retail Customer Class	Projected MWh Sales
Residential	15,450,381
Small General Service	1,927,403
Medium General Service	11,219,433
Large General Service	8,611,892
Lighting	447,233
Total	37,656,341[1]

These class totals were used in Babcock Revised Exhibit 2, Schedule 1, Page 3 in calculating the total fuel and fuel-related cost factors for each customer class.

Public Staff witness Ellis testified that based on his review, it appears that DEP's proposed fuel and fuel-related cost factors and EMFs, as revised in witness Babcock's supplemental testimony, are based on adjusted and reasonable costs. Public Staff witness Edwards recommended EMF increment/(decrement) billing factors calculated by using the adjusted test year North Carolina retail sales level of 37,026,644 MWh and the associated

[1] Rounding difference of 1.

customer class MWh sales amounts recommended by the Company. No other party presented any evidence challenging the amounts presented by the Company.

Based on the evidence presented by the Company, the Public Staff's acceptance of the amounts presented by the Company, and noting the absence of evidence presented to the contrary, the Commission concludes that the projected and normalized levels of sales, generation, and purchased power set forth in the Company's revised exhibits are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSION FOR FINDING OF FACT NO. 12

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witnesses Babcock, Culp, and Weintraub, and the affidavit of Public Staff witness Ellis.

Company witness Babcock recommended fuel and fuel-related prices and expenses as follows:

A. The coal fuel price (including Joint Owners generation) is $38.995/MWh.
B. The gas CT and CC fuel price is $40.477/MWh.
C. The appropriate ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions (collectively, Reagents) expense is $43,471,831.
D. The total nuclear fuel price (including Joint Owners generation) is $7.591/MWh.
E. The total purchase power price (including the impact of JDA Savings Shared) is $40.152/MWh.
F. The adjustment to exclude the cost of mitigation sales is $(35,142,900).
G. Fuel expense recovered through intersystem sales is $(110,616,476).

These amounts are set forth on or derived from Babcock Revised Exhibit 2, Schedule 1, Page 1. The total adjusted system fuel and fuel-related expense in part from the use of these amounts is utilized to calculate the prospective fuel factors recommended by the Company and the Public Staff.

Company witness Culp testified that the average nuclear fuel expense is expected to increase from 0.599¢ per kWh incurred in the test period to approximately 0.759¢ per kWh in the billing period. He testified that although costs of certain components of nuclear fuel are expected to increase in future years, nuclear fuel costs on a cents per kWh basis will likely continue to be a fraction of the cents per kWh cost of fossil fuel.

Company witness Weintraub testified that combining coal and transportation costs, the Company projects average delivered coal costs of approximately $92.85 per ton for the billing period, which represents a 1.6% increase compared to the test period actual cost. He also testified that the current forward prices for natural gas reflect the continued increase in competitively priced supply with an average delivered price of $4.75 per MMBtu through the billing period.

Public Staff witness Ellis testified that, based on upon his review, it appears that DEP's proposed fuel and fuel-related cost factors as revised in witness Babcock's testimony are based on adjusted and reasonable costs.

No other party presented evidence on the level of DEP's fuel prices and expenses.

Based upon the evidence in the record as to the appropriate fuel prices and expenses, the Commission concludes that the fuel prices recommended by Company witness Babcock and accepted by the Public Staff are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witness Babcock and the affidavit of Public Staff witness Ellis.

Consistent with G.S. 62-133.2(a2), witness Babcock demonstrated that the annual increase in the aggregate amount of fuel-related expenses associated with non-capacity purchased power costs, qualifying facility capacity costs, and renewable energy costs does not exceed two percent of DEP's total North Carolina jurisdictional gross revenues for 2012.[1]

Babcock Revised Exhibit 2, Schedule 1, page 3 of 3 provides that the projected fuel costs for the North Carolina retail jurisdiction for use in this proceeding are $1,080,205,261 (consisting of $16,778,446 of renewable and cogeneration power capacity costs, $1,057,640,924 of other fuel costs, and line losses of $5,785,891), calculated by using the sales, generation, pricing, and other amounts addressed in the various Findings of Fact discussed in this Order. Public Staff witness Ellis testified that DEP's proposed fuel and fuel-related cost factors were based on adjusted and reasonable costs.

Aside from the Company and the Public Staff, no other party presented or elicited testimony contesting the Company's projected fuel costs for the North Carolina retail jurisdiction. Based upon the evidence in the record and the absence of any direct testimony to the contrary, the Commission concludes that the Company's projected total fuel cost for the North Carolina retail jurisdiction of $1,080,205,261 is reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 14-19

The evidence supporting these findings of fact is found in the testimony and exhibits of Company witness Babcock and the affidavits of Public Staff witnesses Ellis and Edwards.

Company witness Babcock presented DEP's original fuel and fuel-related expense overcollection and prospective fuel cost factors. Company witness Babcock's supplemental testimony sets forth the projected fuel costs, the amount of over/(under)collection for purposes of the EMF, the method for allocating the increase in fuel costs, the composite fuel cost factors, and the EMFs along with schedules reflecting the stipulated adjustments. Public Staff witness Ellis

[1] See Babcock Workpaper 8.
[2] Rounding difference of 1.

recommended the approval of the prospective and EMF components and total fuel factors (excluding GRT and regulatory fee) set forth in Company witness Babcock's supplemental testimony.

Public Staff witness Edwards testified that the $10,922,481 overrecovery and related interest amount of $2,547,974 are reasonable, broken down as follows:

N.C. Retail Customer Class	Test Period Over/(Under)recovery	Interest
Residential	$(6,064,020)	$ 0
Small General Service	599,965	89,995
Medium General Service	3,884,867	582,730
Large General Service	9,678,359	1,451,753
Lighting	2,823,311	423,496
Total	$10,922,481[2]	$2,547,974

As a result of these amounts, Public Staff witness Edwards recommended the following EMF and EMF interest increment/(decrement) billing factors:

N.C. Retail Customer Class	EMF Increment/ (Decrement) (cents/kWh)	EMF Interest Increment/ (Decrement) (cents/kWh)
Residential	0.040	0.000
Small General Service	(0.033)	(0.005)
Medium General Service	(0.036)	(0.005)
Large General Service	(0.110)	(0.016)
Lighting	(0.634)	(0.095)

These factors are also set forth on Babcock Revised Exhibit 3, pages 1 through 6, and Babcock Revised Exhibit 1.

The Commission concludes that the EMF and EMF interest increment/(decrement) billing factors set forth in the testimony of Public Staff witness Edwards are reasonable and appropriate for use in this proceeding. Company witness Babcock calculated the Company's proposed fuel and fuel-related cost factors using a uniform bill adjustment method. Company witness Babcock's testimony provides that the decrease in fuel costs from the amounts approved in Docket No. E-2, Sub 1031 should be allocated between the rate classes on a uniform percentage basis, using the uniform bill adjustment methodology utilized in past DEP fuel cases approved by the Commission. No party opposed the use of this allocation method.

Based upon the testimony and exhibits in the record, the Commission concludes that DEP's projected fuel cost of $1,080,205,261 for the North Carolina retail jurisdiction is reasonable for use in this proceeding. The Commission also concludes that (1) DEP's EMFs proposed in this proceeding, excluding GRT and the regulatory fee, (2) DEP's prospective fuel cost factors proposed in this proceeding for each of DEP's rate classes, and (3) DEP's EMF interest decrements proposed in this proceeding, excluding GRT and the regulatory fee, are all appropriate. Additionally, the Commission concludes that DEP's decrease in fuel costs from the amounts approved in Docket No. E-2, Sub 1018 should be allocated between the rate classes on a uniform percentage basis, using the uniform bill adjustment methodology approved by the Commission in DEP's past fuel cases.

Tables 3, 4 and 5, and 6, shown in Appendix A pages 1 to 4, summarize the impact of the rates in this case compared with the rates approved in Docket No. E-2, Sub 998, Sub 1018 and E-2, Sub 1023. Table 3, Appendix A page 1 reflects the current Net Billed Rate, which includes the merger fuel-related savings rider approved in Docket No. E-2, Sub 998 (to expire November 30, 2013). Table 4, Appendix A page 2 shows the calculation of the restated base fuel rate in columns (a), (b) and (c). Table 4 also shows the base fuel rate increment as calculated on the restated base fuel rate and the EMF and EMF interest increments (decrements) (columns e, f and g, respectively). The billed rate shown in Table 4 column (g) is calculated by adding the restated base fuel rate, the increment at the restated base fuel rate plus the EMF and EMF interest. Table 5, Appendix A page 3 reflects the increment, EMF and EMF interest from Table 4 calculated to include GRT and regulatory fee (to be reflected in Rider BA). Table 6, Appendix A page 4 shows the net rate change difference by customer class from the Docket E-2, Sub 1023 net billed rate (which includes the merger fuel-related savings rider set to expire November 30, 2013) to the Docket E-2, Sub 1031 billed rate (the merger fuel-related savings are inherent in the rate so the merger fuel-related savings rider is no longer necessary).

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 20-21

The evidence supporting these findings of fact is found in the testimony and exhibits of Company witness Babcock, and the testimony of Public Staff witnesses Hoard.

Company witness Babcock stated that DEP's originally proposed rates included avoided cost amounts associated with the purchases of power from renewable energy facilities as provided under G.S. 62-133.2(a1)(6) for which DEP had not also purchased the associated renewable energy certificates ("RECs") for use in compliance with G.S.62-133.8. After it had filed its initial fuel and fuel-related cost recovery application, DEP concluded that the inclusion of avoided cost in its fuel rates should be limited to only those megawatt hours of renewable energy purchased for which it had purchased the associated RECs. As a result, DEP made adjustments to its actual fuel costs for purposes of computing EMF amounts for April 2012 through July 2013, such that the fuel and fuel-related costs include avoided cost amounts only to the extent that the energy purchased has been generated by a renewable fuel source and the renewable attribute (e.g., the REC) is also being purchased. Company witness Babcock testified that for any megawatt hours of renewable energy purchased for which DEP purchased only the energy and not the REC, DEP included in its costs the actual fuel costs, if any, provided by the energy supplier as would be allowed under G.S. 62-133.2(a1)(7). The EMF adjustments made by DEP are limited to the cost of transactions with only five renewable energy suppliers. In addition, DEP made a similar adjustment to its forecasted fuel and fuel-related costs to remove such amounts that should not be included in fuel and fuel-related costs.

As a result, Company witness Babcock testified that the DEP base fuel factors established in Docket No. E-2, Sub 1023 include certain fuel and fuel-related costs as described above that DEP has since determined should not be considered fuel and fuel-related, but instead should be considered non-fuel costs that should be recovered through its base rates. Therefore, DEP requested that the base fuel factors established in Docket No. E-2, Sub 1023 be restated to remove such costs. The Company asserts that it is reasonable to believe that if such costs had not been included in the base fuel and fuel-related costs factors, they would have been found to be includable in the non-fuel component of rates in Docket No. E-2, Sub 1023, DEP's general rate case docket.

Consequently, DEP requested that the Commission restate the base fuel and fuel-related cost factors approved in the general rate case proceeding and establish a non-adjustable base rate rider to allow the Company to recover those costs that should be removed from its fuel rates and recovered through its non-fuel base rates. Company witness Babcock noted that the requested approach is similar to that approved by this Commission regarding DEC in Docket No. E-7, Sub 934 in 2010, as well as in 1988 regarding Virginia Electric and Power Company in Docket No. E-22, Sub 304. Company witness Babcock's Supplemental Exhibit 8 demonstrates the derivation of the proposed base rate rider. Company witness Babcock testified that the restatement of base fuel rates would allow DEP to accurately compare fuel revenues collected with fuel expenses, for purposes of determining over or under recovery amounts for the EMF for use in future annual fuel proceedings. The Company proposed that the restated base fuel rate and non-fuel base rate rider be effective as of June 1, 2013, when base rates approved in Docket No. E-2, Sub 1023 became effective. As a result, DEP computed its June and July 2012 over/ under recoveries of fuel costs that are included in the EMF in this proceeding based on the proposed restated base fuel factors.

The adjusted net fuel and fuel-related costs factors that DEP proposes for residential, small general service, medium general service, large general service, and lighting customer classes are 2.862¢/kWh, 2.874¢/kWh, 2.818¢/kWh, 2.796¢/kWh, and 3.039¢/kWh, respectively, and DEP requested that they be reflected in rates for service on and after December 1, 2013. These net fuel and fuel-related costs factors represent a uniform 1.3% average rate decrease for all customer classes, which replaces the 1.4% average rate decrease that the Company proposed in its initial fuel filing on June 12, 2013.

Public Staff witness Hoard testified that the Public Staff agrees that the avoided costs removed by DEP in witness Babcock's supplemental testimony should not have been included in DEP's original filing. The Public Staff reviewed the methodology and the calculation of the costs that DEP removed and believes that they are accurate. For the reasons stated by Company witness Babcock, Public Staff witness Hoard stated that the Public Staff agrees that it is reasonable to restate the base fuel and fuel-related factors established in Docket No. E-2, Sub 1023 and to establish a base rate rider to allow DEP to recover those costs that should be removed from its fuel rates and recovered through its non-fuel base rates.

Based on the testimony of Company witness Babcock and Public Staff witness Hoard, the Commission concludes that for the reasons stated by witness Babcock, the base fuel and fuel-related factors established in Docket No. E-2, Sub 1023 should be restated and a base rate rider established to allow DEP to recover those avoided costs that should be removed from its fuel rates and recovered through its non-fuel base rates. As shown in Table 4 the amount of the restatement to the base fuel factors are as follows, excluding GRT and regulatory fee: (0.014)¢/kWh for the Residential class; (0.015)¢/kWh for the Small General Service Class; (0.011)¢/kWh for the Medium General Service class; (0.009)¢/kWh for the Large General Service class; and (0.030)¢/kWh for the Lighting class. The restated base fuel factors excluding GRT and regulatory fee also appear in Table 4 and are as follows, 3.016¢/kWh for the Residential class; 3.005¢/kWh for the Small General Service Class; 2.924¢/kWh for the Medium General Service class; 2.960¢/kWh for the Large General Service class; and 3.662¢/kWh for the Lighting class.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 22

The evidence for this finding of fact is contained in the testimony of Public Staff witness Hoard. Public Staff witness Hoard testified that DEP incurred dead freight charges (liquidated damages) during the test period for failure to meet the minimum tonnage requirements of CSX Transportation and Kanawha River Terminals, LLC ("KRT"), pursuant to long-term transportation contracts. The Company charged the KRT dead freight charges to account 151 – coal inventory. The effect of charging the KRT dead freight charges to account 151 – coal inventory was to spread out the costs over several months as coal was burned. The Company had approximately 90-days of coal burn in its coal inventories during the test period, so it took approximately three months for the KRT charges to be fully reflected in fuel and fuel-related expenses. The Company charged the entire amount of the CSX dead freight charges to fuel and fuel-related expenses during the month of the test period in which DEP incurred those charges because the CSX transportation contract covered deliveries to three DEP locations that were either required or very close to retirement. Public Staff witness Hoard testified that it has been DEP's practice to charge dead freight and similar coal transportation-related charges for operating plants to account 151 – coal inventory.

Witness Hoard recommended that, in its computation of fuel and fuel-related cost over- and under-collections in future monthly fuel reports, DEP reflect dead freight and similar coal transportation charges associated with plants that are no longer operating over a period of three months instead of reflecting the entire amount in the month in which the charges were incurred. As a result, dead freight and similar coal transportation charges for such plants will be reflected in fuel and fuel-related expenses as if the amounts had been charged to account 151 – coal inventory. Public Staff witness Hoard testified that DEP has agreed to the Public Staff's recommendation.

Based on the testimony of Public Staff witness Hoard and the absence of any objection from the Company, the Commission concludes that it is reasonable to require the Company to reflect dead freight and similar coal transportation charges associated with plants that are no longer operating over a period of three months instead of reflecting the entire amount in the month in which the charges were incurred.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 23

The evidence for this finding of fact is contained in the testimony of Company witness Weintraub and Public Staff witness Hinton and is discussed in more detail in Evidence and Conclusions for Finding of Fact No. 5.

The Commission has carefully reviewed the evidence and record in this proceeding. The test period and projected fuel costs, and the proposed factors, including the EMF, are not opposed by any party. Accordingly, the overall fuel calculation, incorporating the conclusions reached herein, results in net fuel and fuel-related cost factors of 2.862¢/kWh for the Residential class, 2.874¢/kWh for the Small General Service class, 2.818¢/kWh for the Medium General Service Class, 2.796¢/kWh for the Large General Service Class, 3.039¢/kWh for the Lighting class, excluding GRT and regulatory fee, consisting of the prospective fuel factors of 2.822¢/kWh, 2.912¢/kWh, 2.859¢/kWh, 2.922¢/kWh, and 3.768¢/kWh, EMF increments (decrements) of 0.040¢/kWh, (0.033)¢/kWh, (0.036)¢/kWh, (0.110)¢/kWh and (0.634)¢/kWh and EMF interest decrements of 0.000¢/kWh, (0.005)¢/kWh, (0.005)¢/kWh, (0.016)¢/kWh and (0.095)¢/kWh for the Residential, Small General Service, Medium General Service, Large General Service, and Lighting classes, all respectively, excluding GRT and regulatory fee.

IT IS, THEREFORE, ORDERED:

1. That, effective for service rendered on and after December 1, 2013, DEP shall restate the ¢/kWh base fuel cost factors established in its North Carolina retail rates in Docket No. E-2, Sub 1023 of 3.030 ¢/kWh for the Residential class, 3.020¢/kWh for the Small General Service class, 2.935¢/kWh for the Medium General Service class, 2.969¢/kWh for the Large General Service class, and 3.692¢/kWh for the Lighting class (all excluding GRT and the regulatory fee) by the following amounts (0.014) ¢/kWh for the Residential class, (0.015) ¢/kWh for the Small General Service class, (0.011)¢/kWh for the Medium General Service class, (0.009)¢/kWh for the Large General Service class, and (0.030)¢/kWh for the Lighting class. The resulting restated base fuel rates are 3.016 ¢/kWh for the Residential class, 3.005¢/kWh for the Small General Service class, 2.924¢/kWh for the Medium General Service class, 2.960¢/kWh for the Large General Service class, and 3.662¢/kWh for the Lighting class (all excluding GRT and the regulatory fee). Further, DEP shall adjust the restated ¢/kWh base fuel cost factors by the fuel and fuel-related adjustments of (0.194) ¢/kWh for the Residential class, (0.093)¢/kWh for the Small General Service class, (0.065)¢/kWh for the Medium General Service class, (0.038)¢/kWh for the Large General Service class, and 0.106¢/kWh for the Lighting class (all excluding GRT and the regulatory fee) Further, DEP shall adjust the resulting approved fuel and fuel-related costs by increments/(decrements) across the customer classes of 0.040¢/kWh for the Residential class, (0.033)¢/kWh for the Small General Service class, (0.036)¢/kWh for the Medium General Service class, (0.110)¢/kWh for the Large General Service class, and (0.634)¢/kWh for the Lighting class (all excluding GRT and the regulatory fee) for the EMF. Lastly, DEP shall adjust the resultant approved fuel and fuel-related costs by the following EMF interest decrements: 0.000¢/kWh for the Residential class, (0.005)¢/kWh for the Small General Service class, (0.005)¢/kWh for the Medium General Service class, (0.016)¢/kWh for the Large General Service class, and (0.095)¢/kWh for the Lighting class (all excluding GRT and the regulatory fee). The EMF and EMF interest increment/(decrements) shall remain in effect for service rendered through November 30, 2014;

2. That the non - fuel base rate established in Docket E-2, Sub 1023 will be adjusted by the following base rate riders for each of DEP's rate classes, excluding GRT and regulatory fee: 0.014¢/kWh for the Residential class; 0.015¢/kWh for the Small General Service Class; 0.011¢/kWh for the Medium General Service class; 0.009¢/kWh for the Large General Service

class; and 0.030¢/kWh for the Lighting class. These non - fuel base rate riders shall be effective until DEP's next general rate case, or until otherwise adjusted by the Commission;

3. That DEP shall file appropriate rate schedules and riders with the Commission in order to implement these approved rate adjustments as soon as practicable;

4. That DEP shall work with the Public Staff to prepare a joint notice to customers of the rate changes ordered by the Commission in Docket No. E-2, Subs 1030, 1031, and 1032, and the Company shall file the proposed customer notice for Commission approval as soon as practicable; and

5. That DEP shall evaluate its natural gas hedging strategy in conjunction with the evaluation of DEC's proposed hedging strategy and file a report in Docket No. E-100, Sub 47A by the end of 2013. In this evaluation, DEP should consider the changes to the term and volume of hedges discussed in the testimony of witness Hinton.

ISSUED BY ORDER OF THE COMMISSION.
This the 25th day of November, 2013.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

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TABLE 3

Docket No. E-2; Sub 998, Sub 1018, and Sub 1023 (all rates exclude GRT & Reg Fee) *cents per kwh*

Class	Base Fuel Rate Sub 1023 (a)	Base Fuel Rate Increment Sub 1018 (b)	EMF[1] Sub 1023 (c)	Net Rate Change Sub 1023 (d) (b) + (c)	Merger Fuel Savings Decrement[2] Sub 998 (e)	Net Billed Rate[3] Sub 1023 (f) (a) + (d) + (e)
Residential	3.030	0.000	0.033	0.033	(0.070)	2.993
Small General Service	3.020	0.000	0.066	0.066	(0.075)	3.011
Medium General General	2.935	0.000	0.036	0.036	(0.053)	2.918
Large General Service	2.969	0.000	(0.046)	(0.046)	(0.043)	2.880
Lighting	3.692	0.000	(0.214)	(0.214)	(0.149)	3.329

1. Babcock Revised Exhibit 1, Line 3
2. Babcock Revised Exhibit 1, Line 2. Expires November 30,2013.
3. Net Billed Rate equals Base Fuel Rate plus Net Rate Change plus Merger Fuel Savings Decrement (Babcock Revised Exhibit 1,Line 4)

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TABLE 4

Docket No. E-2, Sub 1031 (all rates exclude GRT & Reg Fee) cents per kwh

Class	Base Fuel Rate	Base Rate Rider 1	Restated Base Fuel Rate	Fuel and Fuel-related Costs Factor2	Increment (Decrement) at Restated Base Fuel Rate	EMF Increment (Decrement)3	EMF Interest Increment (Decrement)4	Billed Rate
	Sub 1023	Sub 1031	Sub 1023	Sub 1031	Sub 1031	Sub 1031	Sub 1031	Sub 1031
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
			(a)+ (b)		(d) - (c)			(c) +(e) + (f) + (g)
					(0.208)			
Residential	3.030	(0.014)	3.016	2.822	(0.194)	0.040	-	2.862
Small General Service	3.020	(0.015)	3.005	2.912	(0.093)	(0.033)	(0.005)	2.874
Medium General General	2.935	(0.011)	2.924	2.859	(0.065)	(0.036)	(0.005)	2.818
Large General Service	2.969	(0.009)	2.960	2.922	(0.038)	(0.110)	(0.016)	2.796
Lighting	3.692	(0.030)	3.662	3.768	0.106	(0.634)	(0.095)	3.039

1. Babcock Supplemental Exhibit 8, page 1 (last column). This is a negative adjustment to the base fuel rate and a positive adjustment to base rates.
2. Babcock Revised Exhibit 1, Line 9
3. Babcock Revised Exhibit 1, Line 10
4. Babcock Revised Exhibit 1, Line 11

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TABLE 5

Docket No. E-2, Sub 1031 (includes GRT & Reg Fee - as reflected in Rider BA) cents per kwh

Class	Increment (Decrement)1	EMF Increment (Decrement) 2	EMF Interest Increment (Decrement) 3	Net Rate Adjustment
	(a)	(b)	(c)	(d)
				(a) + (b) + (c)
Residential	(0.201)	0.041	-	(0.160)
Small General Service	(0.096)	(0.034)	(0.005)	(0.135)
Medium General General	(0.067)	(0.037)	(0.005)	(0.109)
Large General Service	(0.039)	(0.114)	(0.017)	(0.170)
Lighting	0.110	(0.656)	(0.098)	(0.644)

1. Table 4 Column (e) times 1.034661
2. Table 4 Column (f) times 1.034661
3. Table 4 Column (g) times 1.034661

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TABLE 6

Docket No. E-2, Sub 1031 Net Change to Customer Bills cents per kwh

	Current Fuel Rate @ Restated Base Fuel Rate 1	New Fuel Rate @ Restated Base Fuel Rate 2	Net Rate Change
	(a)	(b)	(c)
			(b) - (c)
Excluding GRT and Regulatory Fee			
Residential	2.979	2.862	(0.117)
Small General Service	2.996	2.874	(0.122)
Medium General General	2.907	2.818	(0.089)
Large General Service	2.871	2.796	(0.075)
Lighting	3.299	3.039	(0.260)
Including GRT and Regulatory Fee			
Residential	3.082	2.960	(0.122)
Small General Service	3.099	2.974	(0.125)
Medium General General	3.007	2.916	(0.091)
Large General Service	2.970	2.893	(0.077)
Lighting	3.414	3.145	(0.269)
Gross Receipts Multplier	1.034661		

1. Table 4 Column (c) + Table 3 Columns (b), (c), (e)
1. Table 4 Column (h)

DOCKET NO. E-7, SUB 1033

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Carolinas, LLC,	)	
Pursuant to G.S. 62-133.2 and NCUC	)	ORDER APPROVING FUEL
Rule R8-55 Relating to Fuel and Fuel Related	)	CHARGE ADJUSTMENT
Charge Adjustments for Electric Utilities	)	
	)	

HEARD: Tuesday, June 4, 2013, at 9:30 a.m. in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman Edward S. Finley, Jr., Presiding, Commissioner ToNola D. Brown-Bland, Commissioner Bryan E. Beatty, Commissioner William T. Culpepper, III, Commissioner Lucy T. Allen

APPEARANCES:

For Duke Energy Carolinas, LLC:

Brian L. Franklin, Associate General Counsel, Duke Energy Corporation 550 South Tryon Street, DEC 45A/PO Box 1321, Charlotte, North Carolina 28201

and

Robert W. Kaylor, Esq., Law Office of Robert W. Kaylor, P.A., 353 Six Forks Road, Suite 260, Raleigh, North Carolina 27609

For the Using and Consuming Public:

Dianna Downey, Staff Attorney, Public Staff, North Carolina Utilities Commission, 430 N. Salisbury Street, 4326 MSC, Raleigh, North Carolina 27699-4326

For North Carolina Sustainable Energy Association:

Michael Youth, Esq., 1111 Haynes Street, Suite 109, Raleigh, North Carolina 27604

For North Carolina Waste Awareness and Reduction Network:

John D. Runkle, Esq., P.O. Box 3793, Chapel Hill, North Carolina 27515

For Carolina Industrial Group for Fair Utility Rates III:

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BY THE COMMISSION: On March 6, 2013, Duke Energy Carolinas, LLC (Duke Energy Carolinas, DEC, or the Company), filed an Application pursuant to G.S. 62-133.2 and Commission Rule R8-55 relating to fuel and fuel-related charge adjustments for electric utilities, along with the testimony and exhibits of Kim H. Smith, Sasha Weintraub, Joseph A. Miller, Jr., Robert J. Duncan, II and David C. Culp.

On March 13, 2013, the Commission issued an Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice. That Order provided that the direct testimony of intervenors should be filed on May 17, 2013, that rebuttal testimony should be filed on May 24, 2013, and that a hearing on this matter would be conducted on June 4, 2013.

On March 25, 2013, Carolina Industrial Group for Fair Utility Rates III (CIGFUR III) filed a petition to intervene. On March 26, 2013, North Carolina Sustainable Energy Association (NCSEA) filed a petition to intervene. On April 3, 2013, Carolina Utility Customers Association, Inc. (CUCA) filed a petition to intervene. These petitions were allowed in Orders dated April 1, 2013 and April 4, 2013.

On April 13, 2013, North Carolina Waste Awareness and Reduction Network (NC WARN) filed a petition to intervene. This petition was allowed in an Order dated April 18, 2013.

The intervention of the Public Staff is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

On May 17, 2013, the Public Staff filed a motion for extension of time to file testimony, and on May 20, 2013, the Commission granted the motion, extending the time for filing Public Staff and intervenor testimony to May 24, 2013, and for filing rebuttal testimony to May 31, 2013.

On May 22, 2013, DEC filed affidavits of publication indicating that public notice had been provided in accordance with the Commission's procedural order.

On May 23, 2013, the Public Staff filed a second motion for extension of time to file testimony, and on May 24, 2013, the Commission granted the motion, extending the time for filing Public Staff and intervenor testimony to May 31, 2013, and for filing rebuttal testimony to June 3, 2013.

On May 31, 2013, the Company filed a Motion for Witnesses to be Excused from Appearance at Evidentiary Hearing, and on June 3, 2013, the Commission issued an Order excusing the appearances of the Company's witnesses David C. Culp and Joseph Miller, Jr. at the evidentiary hearing.

On June 3, 2013, the Company and the Public Staff (Stipulating Parties) filed a Joint Agreement and Stipulation of Settlement (Stipulation). Through the Stipulation, the Company updated its filing to reflect the impact of $431,799 of total system ($294,198 N.C. retail) fuel costs incurred in 2012 inadvertently omitted in its original filing. These fuel costs represent the fuel cost component of other purchased power from a qualifying facility.

Also on June 3, 2013, the Public Staff filed the testimony of James G. Hoard, Randy T. Edwards, and Kennie D. Ellis. On that same date, the Company filed supplemental testimony of Robert J. Duncan, II, and revised exhibits and workpapers of Kim H. Smith. No other party filed testimony, exhibits, or affidavits.

The case came on for hearing as scheduled on June 4, 2013. The prefiled testimony and affidavits and exhibits of the Stipulating Parties' witnesses were received into evidence. No other party presented witnesses, and no public witnesses appeared at the hearing.

On July 2, 2013, Duke and the Public Staff filed a joint motion requesting an extension of time to file briefs and proposed orders to July 15, 2013. On July 5, 2013, the Commission entered an Order granting the motion.

On July 12, 2013, NCSEA filed a letter in lieu of a post hearing brief. In the letter, NCSEA stated that it did not challenge the cost recovery in the Stipulation but requested that the Commission incorporate into its order in this proceeding DEC's commitment to file an updated fuel procurement practices report that includes its proposed natural gas hedging strategy.

On July 15, 2013, the Public Staff filed a motion requesting an extension of time to file briefs and proposed orders to July 19, 2013. On that same date, the Commission entered an Order granting the motion.

The Stipulating Parties filed a joint proposed order on July 18, 2013.

Based upon the Company's verified Application, the testimony and exhibits received into evidence at the hearing, the Stipulation, and the record as a whole, the Commission makes the following:

FINDINGS OF FACT AND CONCLUSIONS

1. Duke Energy Carolinas is a duly organized limited liability company existing under the laws of the State of North Carolina and is engaged in the business of developing, generating, transmitting, distributing, and selling electric power to the public in North Carolina, and is subject to the jurisdiction of the North Carolina Utilities Commission as a public utility. Duke Energy Carolinas is lawfully before this Commission based upon its application filed pursuant to G.S. 62-133.2.

2. The test period for purposes of this proceeding is the 12-month period ended December 31, 2012.

3. In its Application and testimony, DEC requested that its North Carolina retail revenue requirement associated with fuel and fuel-related costs remain essentially the same as that approved in DEC's last fuel proceeding (Docket No. E-7, Sub 1002). The fuel cost factors requested by DEC included Experience Modification Factor (EMF) riders that took into account fuel underrecoveries and overrecoveries experienced during calendar year 2012, with an overall overrecovery of approximately $47 million.

4. The Stipulation filed on June 3, 2013 comprehensively resolved all issues in this proceeding between DEC and the Public Staff. Neither CIGFUR III, CUCA, nor NC WARN filed statements expressing any opinion regarding the Stipulation. NCSEA filed a letter in which it stated it did not oppose the cost recovery agreed to by the Stipulating Parties in the Stipulation. Having carefully reviewed the Stipulation and all the evidence of record, the Commission finds and concludes that the provisions of the Stipulation are just and reasonable to all parties under the circumstances of this proceeding and should be approved in their entirety. The specific terms of the Stipulation are addressed in the following findings of fact and conclusions.

5. One factor contributing to the Company's actual test year fuel costs was the performance of its nuclear plants. G.S. 62-133.2(d) and Commission Rule R8-55 provide that the burden of proof as to the correctness and reasonableness of any charge and as to whether the test year fuel costs were reasonable and prudently incurred is on the utility. For purposes of determining the EMF rider, a utility must achieve either (a) an actual system-wide nuclear capacity factor in the test year that is at least equal to the national average capacity factor for nuclear production facilities based on the most recent 5-year period available as reflected in the most recent North American Reliability Corporation's (NERC) Generating Availability Report, appropriately weighted for size and type of plant (NERC average) or (b) an average system-wide nuclear capacity factor, based upon a two-year simple average of the system-wide capacity factors actually experienced in the test year and the preceding year, that is at least equal to the NERC average, or a presumption is created that the utility imprudently incurred the increased fuel costs and that disallowance of those costs is appropriate.

6. Under the calculation of the most recent NERC average, DEC met and exceeded the performance standard for its plants with a 91.85% nuclear capacity factor, compared to the NERC average of 89.79%.

7. Nevertheless, DEC's nuclear performance was affected by the performance at McGuire Nuclear Station (McGuire), Unit 2 and Catawba Nuclear Station (Catawba), Units 1 and 2. Although McGuire exceeded the NERC average during the test period, it experienced an extended refueling outage at Unit 2. Catawba Unit 2 also exceeded the NERC average. Catawba Unit 1, however, experienced a forced outage event resulting from a cable failure further complicated by a loss of offsite power event for the station, which extended the Unit 2 refueling and maintenance outage underway at the time. After extensive investigation, the Public Staff believes that some of the outage time at McGuire Unit 2 and Catawba Units 1 and 2 during the test year could have been avoided under efficient management and economic operations, and at least some of the associated replacement power costs should be excluded.

8. The Company disagrees with the Public Staff's position. The Company does acknowledge, however, that although its nuclear capacity factor exceeded the NERC average for

the test year, the Catawba and McGuire outages exceeded the scheduled outage duration as a result of equipment and vendor execution challenges.

9. Consistent with the Stipulation, the Commission finds and concludes that it is appropriate for DEC to forgo recovery of a N.C. retail allocated amount of $4,542,857 of replacement power fuel expenses incurred during the test year due to the outage extension at McGuire Unit 2, as well as $757,143 of interest on that amount, for a total of $5,300,000. Additionally, consistent with the Stipulation, the Commission finds and concludes that to the extent DEC succeeds in recovering liquidated damages from the vendor involved in the McGuire Unit 2 outage work, DEC shall flow back half of the net amount, up to $257,143, to ratepayers in a future fuel case. The Commission finds and concludes that this aspect of the Stipulation is just and reasonable.

10. The Commission finds and concludes that any issues with respect to the performance of Catawba and McGuire Unit 2 are adequately addressed and resolved in the Stipulation and DEC managed its other baseload plants prudently and efficiently so as to minimize fuel and fuel-related costs.

11. Except for the replacement power for which costs have been excluded pursuant to this Order, the Company's fuel and reagent procurement and power purchasing practices during the test period were reasonable and prudent.

12. Duke Energy Carolinas' proposal to share pre-merger fuel savings between itself and Duke Energy Progress, Inc. (DEP), is consistent with the treatment of post-merger fuel savings related to the merger of Duke Energy Corporation and Progress Energy, Inc., (Merger) and is thus reasonable and appropriate, so long as DEP reflects the full offsetting amount in its upcoming fuel proceeding. In general, the validity of all Merger fuel-related savings shall remain subject to future Commission determination.

13. The test period per book system sales are 79,868,568 MWh. The test period per book system generation and purchased power is 86,013,644 MWh and is categorized as follows:

Type	MWh
Coal	27,969,376
Biomass	1,365
Oil & Combustion Turbine Gas	923,193
Combined Cycle Natural Gas	4,418,878
Nuclear	42,003,452
Hydro – Conventional	1,400,604
Hydro Pumped storage	(641,599)
Solar	10,479
Purchased Power – Economic and Dispatchable	8,093,358
Renewable Purchased Power	703,681
Other Purchased Power	907,292
Catawba Interchange	223,565
Total	86,013,644

14. The nuclear capacity factor appropriate for use in this proceeding is 92.84%.

15. The adjusted North Carolina retail test period sales for use in calculating the EMF are 55,534,611 MWh. The adjusted North Carolina retail customer class MWh sales are as follows:

N.C. Retail Customer Class	Adjusted kWh Sales
Residential	21,143,695
General Service/Lighting	22,112,646
Industrial	12,278,269
Total	55,534,611[1]

16. The projected billing period sales for use in this proceeding are 82,388,880 MWh on a system basis and 55,516,317 MWh on a N.C. retail basis. The projected billing period N.C. retail customer class MWh sales are as follows:

N.C. Retail Customer Class	Projected MWh Sales
Residential	20,955,314
General Service/Other	22,316,250
Industrial (Including Textiles)	12,244,753
Total	55,516,317

17. The projected billing period system generation and purchased power for use in this proceeding in accordance with projected billing period system sales is 90,164,033 MWh and is categorized as follows:

Type	MWh
Coal	26,277,775
Gas CT and CC	10,016,167
Nuclear	43,440,823
Hydro	1,779,845
Net Pumped Storage Hydro	(798,620)
Purchased Power	9,448,043
Total	90,164,033

The difference of (7,775,153) MWh between projected billing period system generation and purchased power and projected billing period system sales is made up of mitigation sales of (803,900) MWh, intersystem sales of (1,683,858) MWh, and line losses and Company use of (5,287,395) MWh.

[1] Rounding difference of 1.

18. The appropriate fuel and fuel-related prices and expenses for use in this proceeding are as follows:

A. The coal fuel price is $38.023/MWh.
B. The gas CT and CC fuel price is $32.554/MWh.
C. The appropriate ammonia, limestone, urea and dibasic acid (collectively, Reagents) expense is $41,840,169.
D. The total nuclear fuel price (including Catawba Joint Owners generation) is $6.759/MWh.
E. The nuclear fuel price for Catawba Joint Owners generation is $6.759/MWh.
F. The total purchased power price (including the impact of JDA Savings Shared) is $36.52/MWh.
G. The adjustment to exclude the cost of mitigation sales is a reduction of $(29,839,400).
H. The adjusted level of fuel and fuel-related credits associated with intersystem sales is $(66,967,909).

19. The total projected N.C. retail fuel cost for use in this proceeding is $1,287,001,169. This consists of $12,302,413 of renewable and cogeneration power capacity costs and $1,274,698,756 of other fuel costs. Consistent with G.S. 62-133.2(a2), the annual increase in the aggregate amount of fuel-related expenses associated with non-capacity purchased power costs, qualifying facility capacity costs, and renewable energy costs does not exceed two percent of DEC's total North Carolina jurisdictional gross revenues for 2012. In determining whether purchased power costs included in DEC's proposed rates should be limited pursuant to paragraph (a2), DEC performed its evaluation excluding the costs directly related to joint dispatch agreement transactions between DEC and DEP, which are providing merger savings to DEC's North Carolina retail customers. The Commission finds that the exclusion of these costs from the calculation of the annual increase in the aggregate amount of fuel-related expenses associated with non-capacity purchased power costs is just and reasonable.

20. The Company's N.C. retail fuel and fuel-related expense overcollection amounts were $8,086,940, $24,292,108, and $14,927,436 for the Residential, General Service/Lighting, and Industrial customer classes, respectively, for a total of $47,306,484. Including the impact of the costs forgone pursuant to the terms of the Stipulation, the adjusted fuel and fuel-related expense overcollection amount is $51,555,143.

21. Consistent with the Stipulation, the decrease in customer class fuel and fuel-related cost factors from the amounts approved in Docket No. E-7, Sub 1002 should be allocated between the rate classes on a uniform percentage basis, using the uniform bill adjustment methodology that was approved by the Commission in Docket No. E-7, Sub 1002.

22. The appropriate prospective fuel cost factors for this proceeding for each of DEC's rate classes, excluding gross receipts tax (GRT) and the North Carolina Regulatory Fee (NCRF), are as follows: 2.2306¢/kWh for the Residential class, 2.3566¢/kWh for the General Service/Lighting class, and 2.3980¢/kWh for the Industrial class.

23. The appropriate decrement EMFs, including interest but excluding GRT and NCRF, established in this proceeding, are as follows: (0.0534)¢/kWh for the Residential class, (0.1371)¢/kWh for the General Service/Lighting class, and (0.1510)¢/kWh for the Industrial class.

24. The final total fuel and fuel-related cost factors to be billed to DEC's North Carolina retail customers during the 2013-2014 fuel clause billing period are 2.1772¢/kWh for the Residential class, 2.2195¢/kWh for the General Service/Lighting class, and 2.2470¢/kWh for the Industrial class, excluding GRT and NCRF.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

This finding of fact is essentially informational, procedural, and jurisdictional in nature and is uncontroverted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

G.S. 62-133.2(c) sets out the verified, annualized information that each electric utility is required to furnish to the Commission in an annual fuel and fuel-related charge adjustment proceeding for a historical 12-month test period. In Commission Rule R8-55(b), the Commission has prescribed the 12 months ending December 31st as the test period for DEC. The Company's filing was based on the 12 months ended December 31, 2012.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3-4

The evidence for these findings of fact is found in the Application, the testimony of Company witness Smith, the Stipulation, and the entire record in this proceeding. These findings and conclusions are not contested by any party.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5-9

The evidence for these findings of fact is found in the Application, the testimony of Company witness Duncan and of Public Staff witness Ellis, and in the Stipulation.

Commission Rule R8-55(d)(1) provides that capacity factors for nuclear production facilities will be normalized based generally on the national average for nuclear production facilities as reflected in the most recent NERC Equipment Availability Report, adjusted to reflect the unique, inherent characteristics of the utility facilities and any unusual events. Company witness Duncan testified that the Company's seven nuclear units operated at a system average capacity factor of 91.85% during the test period. This capacity factor exceeded the five-year industry weighted average capacity factor of 89.79% for the period 2007-2011 for pressurized water reactors rated at and above 800 MWs, as reported by NERC in its latest Generating Availability Report. According to Company witness Duncan, the Company's system average nuclear capacity factor has been above 90% for 13 consecutive years. Witness Duncan testified that the Company's nuclear performance has improved significantly over the course of the years of operating its nuclear fleet. In particular, shorter refueling outages and improved forced outage rates have contributed to increasing the capacity factors achieved by the Company's nuclear fleet.

Public Staff witness Ellis agreed that DEC's nuclear generation system achieved an overall actual capacity factor of 91.85% during the test period, above the most recent NERC average of 89.79%. He testified that since the Company's nuclear generation system achieved an overall capacity factor above the NERC average, no presumption of imprudence or disallowance of increased fuel costs was created under Commission Rule R8-55(k). However, he testified that the Rule states that the burden of proof as to the correctness and reasonableness of any charge shall be on the utility.

Witness Ellis testified that in particular, the Company's proposed EMF reflected increased fuel costs resulting from the purchase of replacement power during the Catawba Unit 1 forced outage in April 2012, the extension of the Catawba Unit 2 refueling outage during that same time period, and the extension of the McGuire Unit 2 refueling outage in the fall of 2012. Therefore, he testified, the Public Staff undertook to determine what caused these outages and outage extensions, whether the additional costs were reasonable and prudently incurred, and, if not, what adjustment to the Company's proposed EMF was appropriate. Company witness Duncan also testified regarding the causes of the Catawba and McGuire outages in his supplemental testimony.

CATAWBA UNITS 1 AND 2

Public Staff witness Ellis testified that with respect to the Catawba outages, in the spring of 2012, Catawba Unit 1 was operating at full power, while Catawba Unit 2 was in a scheduled refueling outage that had begun on March 20, 2012. On April 4, 2012, Catawba Unit 1 tripped following a trip of a reactor coolant pump. When generator power circuit breakers opened, the Zone G protective relaying system unexpectedly actuated, opening the switchyard breakers, isolating Unit 1 and resulting in a Loss of Offsite Power (LOOP). Because Unit 2's essential busses were aligned to Unit 1's offsite power at the time, those busses lost power when the LOOP occurred. Witness Ellis testified that the Company investigated the causes behind both the trip of the reactor coolant pump and the actuation of the Zone G protective relaying system.

Witness Ellis stated that the Company found that the trip of the reactor coolant pump occurred as a result of a phase to ground fault in the Y phase conductor (a power cable) for the pump motor. According to witness Ellis, in 2000 this reactor coolant pump experienced a similar trip as a result of the pump motor Y phase Elastimold bushing fault to ground, which likely caused thermal damage to the cable and ultimately led to the cable failure that occurred in the spring of 2012.

Witness Ellis testified that with respect to the unexpected actuation of the Zone G relaying system that resulted in the LOOP, the Company determined that during Catawba Unit 1's scheduled outage in 2011, the generator protective relaying was upgraded. The modification (Zone G relay modification) was intended to maximize the reliability of the protective relaying function while minimizing the likelihood of spurious relay actuation. The modification consisted, in part, of adding a redundant train of protective relays for each function and adding two additional functions. The Zone G relaying system trips the switchyard unit tie breakers in the event of a generator underfrequency, separating the turbine generator from the grid. The modification was supposed to include a blocking logic. This blocking logic was not fully incorporated into the Zone G digital relay upgrades.

According to witness Ellis, the omission of the blocking logic from the relay programming was not discovered during the testing phase of the modification because the testing procedures were based upon a calculation that was generated during the vendor's design portion of the modification rather than upon the original design specifications. Consequently, the programming error propagated through the rest of the implementation phase and was undetected during design, review, approval, implementation, and post-modification testing.

Witness Ellis testified that as a result of the omission of the blocking logic, when the reactor trip occurred due to the coolant pump trip, the relay mistakenly detected a generator underfrequency and unexpectedly opened, separating the generator from the grid and causing a LOOP. Catawba Unit 1 was in a forced outage until April 17, 2012, a total of 13 days, as a result of the above-described events.

Company witness Duncan testified that with respect to the Catawba outages, in May-June 2011, during Unit 1's 19th refueling and maintenance outage, DEC upgraded the generator protective relay system for the Unit. This system is designed to detect faults and other off-normal conditions affecting the switchyard or the main turbine generator. The turbine under-frequency protection design change was implemented to address equipment obsolescence and eliminate vulnerability in generator asset protection. The preexisting electro-mechanical relay scheme providing turbine under-frequency protection required upgrade and additional protection with digital components for the generator to protect against catastrophic damage if a ground fault should occur. According to witness Duncan, in implementing the project, DEC developed specifications for a qualified vendor. The scope specification did not specifically call out with particularity a design input for the complex relay scheme and led to the omission of a "block" protection feature that isolates the Unit from the grid when the generator circuit breakers are open following a generator trip.

Witness Duncan testified that the outage in question began on April 4, 2012, when Unit 1 tripped off-line following a trip of the "1D" reactor coolant pump. Shortly thereafter, a portion of the generator protective relay system unexpectedly actuated when it sensed the instantaneous under-frequency condition of the Unit. This actuation opened the switchyard circuit breakers, thereby isolating Unit 1 from the transmission grid which supplies backup power to the Unit, and thereby causing a LOOP. The two emergency standby diesel generators automatically started as designed and powered the Unit until, five and a half hours later, offsite power was restored. According to witness Duncan, both the loss of reactor coolant pump flow and resultant reactor trip and the LOOP are events analyzed for safety as part of the plant's original license submittal, and the Unit is designed to safely shut down from such events.

Witness Duncan stated that the Company evaluated the situation and concluded that the 1D reactor coolant pump trip was caused by thermal damage to insulation on a reactor coolant pump motor power cable associated with a historic event in 2000, as well as degradation over time of the cable. The thermal damage was undetected and, in 2000, not readily detectable by cost-effective non-destructive testing methods then available. In April 2012, the cable "faulted to ground" at the location of the thermal damage. The faulted reactor coolant pump motor cable was replaced.

Witness Duncan testified that the old protection scheme used a series of relays and timers in a stepped protective relay scheme at various settings at different frequencies. Because the blocking scheme was not fully incorporated into the revised design, when the Unit's main generator tripped, the Unit was isolated from the grid when, as intended, the upgraded design should have blocked the isolation.

According to witness Duncan, the Company utilized its highest level of risk management for the design change. Prior to the design change, DEC held numerous meetings with the vendor and reviewed the vendor's efforts throughout the design change process. During this review process, DEC spent hundreds of hours in design review, including review of computer coding but not source code, which is proprietary to the vendor. This source code contains algorithms for "accumulating" time related to relay functions. Based on programming coding reviewed by DEC, the accumulating function appeared to be designed correctly.

Witness Duncan stated that the relay programming is proprietary to the vendor and represents the vehicle for ensuring relay logic and schemes are executed as designed. In their review of the relay programming, DEC personnel reviewed the coding language to ensure time accumulation functions were present in each of the four zones of protection designed. The DEC personnel were not aware, however, that while the code variable programmed for Zones 1, 2, and 3 would work as designed to accumulate minutes, it would not work in Zone 4 to accumulate milliseconds. Because the source code was proprietary, the time segmentation of these accumulation algorithms was not disclosed to DEC personnel. According to witness Duncan, the error in the accumulation algorithm in the protection scheme is the source of the design error and was carried forward into the accept testing.

MCGUIRE UNIT 2

Public Staff witness Ellis stated that the McGuire Unit 2 outage involved not only the refueling of the unit, but also the replacement of the generator stator and high pressure turbine rotor. He testified that although the Company had experience with replacing this type of equipment, this was a significant project for McGuire, and was one of the largest projects of its kind in DEC's nuclear history. He also testified that the contract to perform this work was awarded to Siemens USA (Siemens), which manufactured the stator, and that the outage started on September 15, 2012. According to Public Staff witness Ellis, soon after the outage began, vendor-related human performance issues emerged. The Company and Siemens' management repeatedly reminded workers to return to appropriate behaviors to minimize hazards. In a letter to Siemens dated October 4, 2012, Company management expressed dissatisfaction with Siemens' implementation performance, which included not only injuries and dropped objects, but also issues with foreign material in the generator stator and foreign material exclusion (FME) control issues. Witness Ellis testified that FME controls are developed and utilized to ensure that all tools and personnel entering in an FME area are logged in and checked for loose items, and checked again when exiting the FME area. Tools are checked for loose or missing parts, and workers are checked for loose items, such as coins or pens.

Public Staff witness Ellis testified that on October 14, 2012, during the course of the replacement of the main generator stator, it was discovered that a 5/16" nut and washer were missing from a tool (known as a "come along") that was used during the stator rebuild. The tool had been inspected and logged before being brought into the FME zone (FMEZ). At the time it was discovered that the nut and washer were missing, the generator rotor had already been reinstalled, and the turbine end and exciter end of the generator were being built. Witness Ellis testified that due to the risks associated with leaving the parts in the generator, DEC's management decided to undertake a search for the nut and washer by removing the generator rotor to ensure all foreign materials were in fact removed. The nut and washer were never found, but DEC did find metallic drill tailings from initial fabrication and installation, one of which was four inches long, which could have caused significant damage had they not been removed. Specifically, he noted that a loose metallic part left in the main generator (especially the windings or stator core) can result in damage to the windings, fault of the stator, subsequent generator, turbine and reactor trip, the potential for a complicated trip (e.g. a LOOP) due to protective relay actuations, the potential for release of hydrogen from the generator, and the risk of explosive gas and fire, catastrophic failure, and personal injury. The search for the nut and washer, removal of the foreign material found, and reinstallation of the turbine rotor extended the outage for an additional 10 days.

Public Staff witness Ellis stated that on October 17, 2012, DEC again sent Siemens a letter expressing dissatisfaction with Siemens' performance and requested a face to face meeting to discuss a recovery plan for the project. On October 26, 2012, Siemens began to undertake final generator alignment. Witness Ellis explained that in undertaking this activity, it is important that the weight of the generator is evenly distributed on its four corners; otherwise, an unacceptable and unsustainable amount of vibration can result. Siemens recommended performing Frame Foot Loading (FFL) using strain gauges to ensure that the weight of the generator was evenly distributed on the four corners of the generator. Witness Ellis stated that although the FFL method is commonly used in the industry, DEC's experience with aligning generators had been to use the step shimming method, which steps down the shim configuration from the four corners of the generator to ensure the load is distributed appropriately. The Company agreed, however, with the use of FFL to accomplish this task. Witness Ellis testified that although the alignment using FFL progressed well at first, early on October 29, 2012, Siemens personnel began to note inconsistent and unexpected readings from the gauges. The Company's review of the FFL data indicated that the data was unpredictable and unreliable. In reviewing the details of the data on various moves made, DEC questioned the adequacy of Siemens' process controls and verification of key data points. Ultimately, DEC stopped the FFL process and resorted to using the manual validation of step shimming, but the poor execution of the FFL resulted in a delay of almost 5 days. Public Staff witness Ellis testified that the McGuire Unit 2 outage ended on November 30, 2012, approximately 38 days longer than originally scheduled.

Company witness Duncan testified that the McGuire outage involved a significant scope of work, including replacement of the main generator stator, exciter, and support systems, upgrade of the high pressure turbine, and modification of the turbine generator support systems. Generator-turbine projects such as this increase the capacity and improve the reliability of the unit. Witness Duncan testified that managing FME during an outage is highly challenging across the nuclear industry, and that loose metallic objects in the generator have potentially high adverse consequences, including damage to the generator, reactor trips and personnel injury.

Company witness Duncan testified that prior to a planned outage such as the McGuire Unit 2 outage, DEC develops a detailed schedule for the outage and for the major tasks to be performed, including sub-schedules for particular activities, and aggressively attempts to meet its best overall outage time for each outage and measures itself against that schedule. Additionally, DEC performs detailed self-critical analyses of each outage project and applies any lessons learned to ensure continuous improvement. Company witness Duncan also stated that rework due to foreign material contributed to the outage extension at McGuire. Specifically, on October 14, 2012, a day-shift craft millwright raised a concern that a 5/16” nut and lockwasher were missing from a 1.5-ton lever-operated hoist as the hoist was being removed from the Unit’s FMEZ. After extensive inspections, including removal of the generator’s rotor, the missing parts were not located. Company witness Duncan testified that the removal of the rotor was a decision that prolonged the outage, but also elevated plant equipment reliability and personnel safety over economic concerns.

Company witness Duncan stated that even though DEC and its contractor had implemented FME control efforts prior to the outage, and FME technicians inspected tools, including the hoist (i.e. the “come-along”), prior to entry into the FMEZ, the extensive searches were reasonable and appropriate to assure that the missing parts were not in the generator. In doing so, the Company talked to the craft laborer and the FME technician who inspected the hoist prior to its entry into the FMEZ. The FME technician who inspected the tool prior to entry into the FMEZ stated that he performed the inspection and that he understood his training and the FME procedures regarding checking tools for loose parts; however, he could not specifically recall whether the nut and lockwasher were missing when he logged the hoist. The technician could not recall whether the nut and lockwasher were present or missing when the hoist entered the FMEZ. Therefore, DEC could not rule out the possibility that the parts were in the FMEZ. Only in hindsight, after the search and the uneventful startup and operation of the generator, did DEC know that the missing parts may well have been missing prior to the hoist’s entry into the FMEZ.

Company witness Duncan testified that the outage extension was also affected by problems encountered by a qualified contractor in the FFL for the large electric main generator. The Company held the expectation that the leveling process, referred to as “shimming,” could be achieved in the time scheduled for the task. A new main turbine generator was installed during this outage, making extensive alignment necessary. Excessive vibration during generator startup would require the Unit to shut down until the source of the vibration, which in and of itself could cause equipment damage, could be identified and eliminated, so achieving an adequate alignment was a high priority. During outage planning, DEC and the contractor considered aligning the generator using either FFL or step shimming. According to witness Duncan, step shimming is simpler and more straightforward than FFL, but is much less accurate and can be inconclusive until generator startup. FFL produces a more accurate alignment but takes more time, is more complex, and requires more shim movements with a higher level of assurance of low vibration at startup. Before recent technological advances made FFL easier to perform, FFL was reserved for problematic alignments where excessive vibration had been observed in the main turbine generator.

Company witness Duncan testified that prior to the performance of the FFL at McGuire, DEC's subject matter experts performed quality reviews of the contractor's work packages for FFL, including the contractor's proprietary documents that relate to FFL technique. The Company also developed procedures to govern DEC's oversight of the contractor. Further, during execution efforts, DEC remained engaged asking questions of the contractor. Only after the contractor's 16th move was DEC aware that the contractor, and the contractor's technique, might not achieve desired results. At this point, DEC applied oversight resources to the contractor's conduct of the work. While monitoring the contractor's performance of FFL from moves 16 to 25, DEC noted several shortcomings in the contractor's performance and brought these to the contractor's attention. Following DEC's decision to intervene, DEC achieved an acceptable alignment in approximately one day. Company witness Duncan testified that consistent with nuclear industry practice, DEC and its vendor actively engaged in a self-critical post-outage critique process and developed a project plan to incorporate lessons learned and guide a similar scope of work performed during the McGuire Unit 1 spring 2013 refueling outage. Company witness Duncan also testified that the Company believes it is key to place each outage event in its proper context and focus attention on the facts and circumstances as they existed at the time of each incident without the benefit of hindsight, including key decisions leading up to these events, and that DEC disagrees with the Public Staff's conclusions on certain portions of those outages.

Both the Company and the Public Staff acknowledged that notwithstanding the circumstances regarding the McGuire and Catawba outages and the delays and increased fuel costs involved, reasonable persons with knowledge and experience in nuclear operations can disagree as to, as Public Staff witness Ellis testified, the prudence of specific actions or inactions that caused delays and resulted in increased fuel costs during an outage, particularly an outage that included major upgrades to a nuclear unit, or as Company witness Duncan testified, the drivers of specific outage delays. The Public Staff acknowledged that the Company made efforts to mitigate the effects of the delays at McGuire caused by Siemens' performance and developed recovery plans for the project in conjunction with Siemens, and believes that DEC's decision to remove the rotor to conduct further searches for a potential missing nut and washer was reasonable and prudent under the circumstances. In addition, the Company developed corrective action plans for the Catawba LOOP event aimed at preventing future such events. Considering all of these factors, the Public Staff and DEC believed it appropriate to engage in settlement discussions regarding an adjustment to test period fuel costs that would be fair to the Company and to its ratepayers.

Consequently, the Stipulating Parties agree that DEC will forgo recovery of $4,542,857 of replacement power fuel expenses incurred during the test year due to the outage extension at McGuire, as well as $757,143 of interest on that amount, for a total of $5,300,000. Additionally, to the extent that DEC succeeds in recovering liquidated damages from the vendor involved in the McGuire outage work, DEC agrees to flow back half of the net amount, up to $257,143, to ratepayers in a future fuel case. The Stipulating Parties agree that the above amounts represent a fair and reasonable resolution of the issue of test year fuel costs that the Public Staff believes should not be recovered from ratepayers because of the challenges experienced at Catawba and McGuire. The Stipulating Parties further agree that by agreeing to settle this issue, DEC in no way concedes that it was imprudent, unreasonable, inefficient, or uneconomical in incurring its fuel costs during the test period or in managing its generation fleet, and that the Stipulation in no way constitutes a waiver or acceptance of the position of any Party concerning the requirements of G.S. 62-133.2, or Commission Rule R8-55, in any future proceeding, nor does it constitute a waiver of any right to assert or oppose a position in any future proceeding or any court. Moreover, the Stipulating Parties agree that the Stipulation does not establish any precedent with respect to the issues resolved herein, and in no way precludes any Stipulating Party herein from advocating an alternative position or methodology in any future proceeding. No party expressed any opposition to the Stipulation or its terms.

Having carefully reviewed the Stipulation and all the evidence of record, the Commission finds and concludes that these provisions of the Stipulation are just and reasonable to all parties under the circumstances of this proceeding and should be approved in their entirety.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The evidence for this finding of fact is found in the testimony of Company witnesses Duncan and Miller and Public Staff witness Ellis.

Evidence concerning the performance of Catawba and McGuire during the test year is discussed in the Evidence and Conclusions for Findings of Fact Nos. 5-9. Company witness Duncan testified concerning the performance of the rest of the Company’s nuclear fleet and the overall performance of the nuclear fleet during the test period. He testified that overall, DEC’s nuclear stations operated well during 2012, and supplied 62% of the power used by its Carolinas customers in the test period. The seven nuclear units operated at a system average capacity factor of 91.85%. The capacity factor for McGuire Unit 1 was 104.67%, an annual record for the unit. McGuire Unit 2 concluded a 528-day continuous run leading up to the fall refueling outage – the longest continuous run in McGuire history. This also ended a 335-day continuous dual-unit run, setting another station record. Oconee Nuclear Station (Oconee), Unit 3 set a unit record by concluding a 446-day continuous run leading up to its refueling outage, and Oconee set a new record in the 2nd quarter of 2012 with a capacity factor of 102.68%.

Company witness Duncan also noted that in 2012 the Company implemented the second upgrade of an integrated digital reactor protection system and engineering safeguards (RPS/ES) technology on Oconee Unit 3. The Company was able to reduce the length of the outage on this second upgrade by 14 days from the Unit 1 upgrade, and more efficiently completed the refueling and maintenance work due in large part to the application of lessons learned from the Unit 1 RPS/ES implementation. As a follow-up to the Unit 1 upgrade, the Company was recognized and received multiple awards, including the “Engineering Project of the Year’ Award at the 13th Annual Platt’s Global Energy Awards ceremony, and the Nuclear Energy Institute’s “Best of the Best” Top Industry Practice award.

Company witness Miller testified concerning the performance of the Company’s fossil/hydro assets. He testified that the primary objective of the Company’s fossil/hydro generation department is to safely provide reliable and cost-effective electricity to DEC’s customers, and that it achieves this objective by focusing on a number of key areas. He stated that environmental compliance is a “first principle”, that DEC works very hard to achieve high level results, and that DEC achieves compliance with all applicable environmental regulations and maintains station equipment and systems in a cost-effective manner to ensure reliability. The

Company also takes action in a timely manner to implement work plans and projects that enhance the safety and performance of systems, equipment, and personnel, consistent with providing low-cost power for its customers. Equipment inspection and maintenance outages are scheduled during the spring and fall months when electricity demand is reduced due to weather conditions. Witness Miller testified that these outages are well-planned and executed with the primary purpose of preparing the unit for reliable operation until the next planned outage.

Company witness Miller also testified that during the test period, the coal-fired units achieved a fleet-wide availability factor of 90.0% for the review period, and 96.5% during the 2012 summer peak months. He further testified that the hydroelectric fleet had outstanding operational performance during the test period, with a system availability factor of 93.4%. This availability factor measurement refers to the percentage of a given time period that the coal-fired or hydroelectric units were available to operate at full power, if needed. This availability measure is not affected by the manner in which the unit is dispatched, but is impacted by the amount of unit outage time. Additionally, witness Miller noted that the Company's large combustion turbine units were available as needed with a starting reliability of 99.2%.

Company witness Miller also testified concerning significant planned outages occurring at the Company's fossil and hydroelectric facilities during the test period. He testified that in general, planned maintenance outages for all fossil and larger hydroelectric units are scheduled for the spring and fall to maximize the units' availability during periods of peak demand. During the test period, while most of these units had at least one small planned outage to inspect and repair critical equipment or for the final tie-in of new environmental control equipment, three of the coal-fired units had extended planned outages of six weeks or more.

Public Staff witness Ellis testified that the Oconee Unit 1 and Unit 2 outages were within the scope of expected plant operations and that overall, except for Catawba and McGuire Unit 2, the DEC nuclear fleet performed well during the test year. No other party contested the reasonableness and prudence of DEC's operation of its nuclear or fossil/hydro generation system. Based upon the evidence in the record, the Commission concludes that any issues with respect to the performance of Catawba and McGuire Unit 2 are adequately addressed and resolved in the Stipulation and DEC managed its other baseload plants prudently and efficiently so as to minimize fuel and fuel-related costs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

Commission Rule R8-52(b) requires each electric utility to file a Fuel Procurement Practices Report at least once every 10 years and each time the utility's fuel procurement practices change. The Company's updated fuel procurement practices were filed with the Commission in Docket No. E-100, Sub 47A in July 2004, and were in effect throughout the 12 months ending December 31, 2012. In addition, the Company files monthly reports of its fuel and fuel-related costs pursuant to Commission Rule R8-52(a). Further evidence for this finding of fact is found in the testimony of Company witnesses Smith, Weintraub, Miller, and Culp.

Company witness Smith testified that DEC's fuel procurement strategies that mitigate volatility in supply costs are a key factor in DEC's ability to maintain lower fuel and fuel-related rates. Other key factors include DEC's diverse generating portfolio mix of nuclear, coal, natural gas, and hydro; lower natural gas prices; the capacity factors of its nuclear fleet; the combination of DEC's and DEP's respective skills in procuring, transporting, managing and blending fuels and reagents; and the increased and broader purchasing ability of the combined Company as well as the joint dispatch of DEC's and DEP's generation resources. Company witness Weintraub described the Company's fossil fuel procurement practices, set out in Weintraub Exhibit 1. Those practices include computing near and long-term consumption forecasts, determining and designing inventory targets, inviting proposals from all qualified suppliers, awarding contracts based on the lowest evaluated offer, monitoring delivered coal volume and quality against contract commitments, and conducting short-term and spot purchases to supplement term supply. According to witness Weintraub, the Company's average delivered coal cost per ton increased 5.3%, from $94.52 per ton in 2011 to $99.52 per ton in 2012. The Company's transportation costs increased approximately 8.6%, from $27.00 per ton in 2011 to $29.32 per ton in 2012. He testified that coal markets continue to be in a state of flux due to a number of factors, including (1) recent U.S. Environmental Protection Agency regulations for power plants that result in utilities retiring or modifying plants, which lower total domestic steam coal demand, and can result in some plants shifting coal sources to different basins; (2) continuing growth in global demand for both steam and metallurgical coal, which makes coal exports increasingly attractive to U.S. coal producers; (3) continued low gas prices combined with installation of new combined cycle (CC) generation by utilities, especially in the Southeast, which also lowers overall coal demand; and (4) increasingly stringent safety regulations for mining operations, which result in higher costs and lower productivity. According to witness Weintraub, due to increasingly lower power prices and reduced demand for coal generation, coal burn projections for 2013 and forward are forecasted to be lower than historical volumes. The actual coal burn for DEC's stations in 2012 was just over 10,700,000 tons, approximately 30% less than the average coal burn over the prior five-year period of over 15,900,000 tons. Based on the low coal burns in 2012, as well as the downward projection for coal burns in 2013 as compared to the amount of coal under contract for delivery in 2013, DEC expects coal inventories to be above target levels during 2013. Witness Weintraub testified that if the Company experiences mild weather and continued low purchased power prices, there likely will be further upward pressure on coal inventories. He also testified that combining coal and transportation costs, DEC projects average delivered coal costs of approximately $98.62 per ton for the billing period.

Company witness Weintraub also testified that DEC's primary source of coal supply is no longer the Central Appalachian region. Historically, fuel switching to a different coal basin has been difficult for DEC because coal quality characteristics vary greatly between coal producing basins, and the design of DEC's plants was meant to optimize the use of Central Appalachian coals. As a result of the Merger, however, DEC can achieve fuel savings by sharing best practices between DEC and DEP for coal blending at their respective coal-fired plants. Specifically, investments by DEP, which have included improvements to the coal-fired boilers as well as the balance-of-plant components, have expanded the types of coal that DEP can reliably burn at its units, and DEC has been able to learn via the Merger from the DEP practices of consuming non-traditional coals at the DEP coal units without impacting reliability or operations. Because of the sharing of best practices across the DEC and DEP coal generation fleet, DEC can now procure a wide variety of coals for its fleet, resulting in overall fuel savings passed on to customers.

Company witness Weintraub testified that the Company's natural gas consumption is expected to continue to increase. The Company consumed approximately 42 billion cubic feet (Bcf) of natural gas in 2012, compared to approximately 10 Bcf in 2011. This increase was driven by the downward trend in natural gas prices as well as the operation of the Buck CC facility for its first full year ending on December 31, 2012. For 2013, DEC's current forecasted natural gas consumption is approximately 74 Bcf. This forecast is based on current natural gas prices, which are forecasted to remain low, and includes a full year of operations of the Dan River CC facility, which went into commercial service in December 2012. Witness Weintraub also testified that the development of shale gas has created a fundamental shift in the nation's natural gas market. Shale gas is natural gas that is trapped within shale formations, and which can provide an abundant source of petroleum and natural gas. Within recent years, improvements in production technologies have allowed greater access to the natural gas trapped in these formations, and has resulted in increased reserves that can produce natural gas supply more quickly and economically. Given continued production increases, natural gas prices continue to remain at lower levels. The Company's average price of gas purchased for calendar year 2012 was $3.34 per Million British Thermal Units (MMBtu), compared to $4.85 per MMBtu in 2011.

Witness Weintraub noted that DEC does not currently employ a hedging strategy to fix prices on a portion of the projected natural gas usage, and that the lower and unpredictable nature of DEC's historical natural gas usage was not suitable for a structured price hedging program. He also noted that DEC is currently evaluating the feasibility of a hedging program given the increased and more predictable natural gas consumption associated with the addition of the Buck and Dan River CCs. In an update to the Commission at the evidentiary hearing, the Company stated that no later than six months from the date of the evidentiary hearing, DEC would file an updated fuel procurement practices report in Docket No. E-100, Sub 47 that would include, for the first time, a proposed natural gas hedging strategy for DEC.

G.S. 62-133.2(a1)(2) permits DEC to recover the cost of "ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions" (referred to by DEC's witnesses as "reagents"). Company witness Miller testified that DEC has installed pollution control equipment in order to meet various current federal, state, and local reduction requirements for nitrogen oxides (NO_x) and sulfur dioxide (SO_2) emissions. The selective catalytic (SCR) technology that DEC currently operates uses ammonia or, in the case of Marshall Unit 3, urea that is converted to ammonia, for NO_x removal. The selective non-catalytic reduction (SNCR) technology injects urea into the boiler for NO_x removal and the scrubber technology employed by the Company uses crushed limestone for SO_2 removal. Dibasic acid can also be used with the scrubber technology for additional SO_2 removal. SCR equipment is also an integral part of the design of the Buck and Dan River CC Stations. The Company also uses aqueous ammonia for NO_x removal.

Witness Miller also testified that the type and quantity of chemicals used to reduce emissions at the plants varies depending on the generation output of the unit, the chemical constituents in the fuel burned, and/or the level of emission reduction required. As a result, DEC uses chemicals such as limestone, ammonia, urea, and dibasic acid, as well as chemicals such as magnesium hydroxide and calcium carbonate, which are used in order to mitigate increased sulfur trioxide (SO_3) emissions due to consumption of higher sulfur coals pursuant to DEC's fuel flexibility efforts as described by Company witness Weintraub. Witness Miller stated that DEC is managing the impacts, favorable or unfavorable, as a result of changes to the fuel mix and/or changes in coal burn due to competing fuels and utilization of non-traditional coals, and that DEC's goal is to effectively comply with emission regulations and provide the most efficient total-cost solution for operation of the unit.

Company witness Culp testified as to DEC's nuclear fuel procurement practices, which involve computing near and long-term consumption forecasts, establishing nuclear system inventory levels, projecting required annual fuel purchases, requesting proposals from qualified suppliers, negotiating a portfolio of spot and long-term contracts from diverse sources of supply, assessing spot market opportunities, and monitoring deliveries against contract commitments. As described by Company witness Culp, for uranium concentrates as well as conversion and enrichment services, long-term contracts are used extensively in the industry to cover forward requirements and ensure security of supply. The typical initial delivery under new long-term contracts has grown to several years after contract execution because many proven, reliable producers have sold their near-term capacity. For this reason, DEC relies extensively on long-term contracts to cover the largest portion of its forward requirements. By staggering long-term contracts over time for these components of the nuclear fuel cycle, the Company's purchases within a given year consist of a blend of contract prices negotiated at many different periods in the markets, which has the effect of smoothing out the Company's exposure to price volatility. Diversifying fuel suppliers reduces the Company's exposure to possible disruptions from any single source of supply. Due to the technical complexities of changing fabrication services suppliers, DEC generally sources these services to a single domestic supplier on a plant-by-plant basis, using multi-year contracts.

G.S. 62-133.2(a1)(4), (5), (6) , and (7) permit the recovery of the cost of non-capacity power purchases subject to economic dispatch; capacity costs of power purchases associated with qualifying facilities subject to economic dispatch; certain costs associated with power purchases from renewable energy facilities; and the fuel costs of other power purchases. Witness Weintraub testified that DEC (and DEP) consider the latest forecasted fuel prices, outages at the generating units based on planned maintenance and refueling schedules, forced outages at generating units based on historical trends, generating unit performance parameters, and expected market conditions associated with power purchases and off-system sales opportunities in order to determine the most economic and reliable means of serving their customers.

No other party presented or elicited testimony contesting the Company's fuel and reagent procurement and power purchasing practices. Based upon the fuel procurement practices report, the evidence in the record, and the absence of any direct testimony to the contrary, the Commission concludes that these practices were reasonable and prudent during the test period. Consistent with the representation of DEC at the evidentiary hearing, no later than December 31, 2013, DEC will file an updated fuel procurement practices report in Docket No. E-100, Sub 47 that will include a natural gas hedging strategy for DEC.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence supporting this finding of fact and conclusion is contained in the testimony of Company witness Weintraub and Public Staff witness Hoard.

Company witness Weintraub testified about the Joint Dispatch Agreement (JDA), which is an agreement between DEP and DEC where DEC acts as the Joint Dispatcher for DEC's and DEP's power supply resources. The JDA has allowed DEC's and DEP's generation resources to be dispatched as a single system to meet the two utilities' retail and firm wholesale customers' requirements at the lowest possible cost. As a result, the joint dispatch process allows DEC and DEP to serve their retail and wholesale native load customers more efficiently and economically than they can on a stand-alone basis. The JDA also provides a methodology for calculating the savings generated by the joint dispatch process and for equitably allocating the savings between DEC and DEP. The joint dispatch savings will automatically flow through to the Companies' retail customers through their fuel clauses. For native load wholesale customers, the joint dispatch savings are passed through as permitted by the applicable wholesale contracts. Under the joint dispatch process, the energy costs attributable to each utility's native load are the costs actually incurred by the utility for energy allocated to native load service, adjusted by the cost allocation payments calculated by the Joint Dispatcher, which are treated as purchases and sales between the Companies. As a result, the energy cost totals ultimately incurred by DEC and DEP to serve their respective native loads will be equal to the stand-alone costs they would have incurred but for the joint dispatch arrangement, less each utility's share of the joint dispatch savings.

Public Staff witness Hoard explained that pursuant to the Commission's June 29, 2012 Order, in Docket No. E-2, Sub 998 and E-7, Sub 986 (Merger Order), the North Carolina retail customers of DEC and DEP (Utilities) have been guaranteed receipt of their allocable share of \$686.8 million in fuel and fuel-related cost savings resulting from the Merger over a five-year period through the annual fuel charge proceedings of the Utilities. The five-year period may be extended by 18 months if ratepayers have not received their allocable share of the guaranteed savings at the end of the five-year period and the decline in natural gas prices has resulted in the delivery of less coal to certain DEC coal-fired plants. In addition, DEC and DEP are required to file monthly reports of tracked fuel savings with their Monthly Fuel Reports filed under Commission Rule R8-52. These reports of tracked fuel savings must show fuel savings broken down by the following categories: (a) total system, (b) DEC, (c) DEC North Carolina retail, (d) DEP, and (e) DEP North Carolina retail. If at the end of the guaranteed savings period the North Carolina retail customers of the Utilities have not received their allocable shares of the guaranteed fuel savings, the remaining amount shall be reflected as an adjustment in the first fuel cost proceedings of DEC and DEP following the end of the guaranteed savings period.

Witness Hoard provided the following chart that shows details of the fuel savings through the end of the test period that have been reported by the Utilities:

TABLE 1

Item	DE Carolinas	DE Progress	Combined
	(a)	(b)	(c)
Joint Dispatch	$11,328,001	$2,820,299	$14,148,300
Coal Blending	23,524,131		23,524,131
Coal Procurement	1,624,630	2,475,010	4,099,640
Coal Transportation	2,181,451	1,805,939	3,987,390
Reagent Procurement & Transportation	450,300	689,849	1,140,149
Natural Gas Supply & Capacity	4,754,353		4,754,353
Avoided Trading Desk	215,724		215,724
Total	$44,078,590	$7,791,097	$51,869,687

The combined amounts shown in column (c) above are the sum of the savings that originated in each utility. These fuel savings are reflected in the actual expenses reported by the originating utility; the amount of the combined fuel savings is allocated between DEC and DEP each month based on the Utilities' relative MWh generation. As a result, an accounting entry has been recorded each month since the Merger closed to transfer savings that exceed the allocated share of the originating utility to the other utility. Witness Hoard also provided the following Table 2 that shows the amount of fuel savings that were transferred by DEC to DEP during the test period:

TABLE 2

Item	DE Carolinas		
	Gross Amount	Allocated Share	Transferred
	(a)	(b)	(c)
Joint Dispatch	$11,328,001	$8,316,083	$3,011,918
Coal Blending	23,524,131	17,514,516	6,009,615
Coal Procurement	1,624,630	2,399,044	(774,414)
Coal Transportation	2,181,451	2,165,421	16,030
Reagent Procurement & Transportation	450,300	560,574	(110,274)
Natural Gas Supply & Capacity	4,754,353	2,807,572	1,946,781
Avoided Trading Desk	215,724	127,539	88,185
Total	$44,078,590	$33,890,749	$10,187,841

The total amount shown in column (c) is the difference between the gross amount originating with DEC and its allocated share of combined savings. The Joint Dispatch amount shown above is composed of the savings transferred to DEP of $3,558,502 that is included in Schedule 3 of the Monthly Fuel Reports as Purchased Power, less the savings transferred from DEP of $546,584 that is included as Intersystem Sales. The increase in DEC's Purchased Power (debit) represents the DEP portion of Joint Dispatch savings that DEC realized on Joint Dispatch transactions, including energy transfers provided by DEP. The increase in DEC's Intersystem Sales (credit) represents the DEC portion of Joint Dispatch savings that DEP realized on Joint Dispatch transactions, including energy transfers provided by DEC.

Witness Hoard explained that the Coal Blending, Coal Procurement, and Coal Transportation fuel savings amounts transferred between DEC and DEP are reflected in the Steam Generation section, Account 0501016, of Monthly Fuel Report Schedule 2, page 1 of 2.

According to witness Hoard, all of the Coal Blending savings originate in DEC, because they result from the implementation of coal blending at the DEC coal-fired plants. DEP, which implemented coal blending at its coal-fired plants in 2006, already has considerable experience with coal blending. Because DEP fully implemented coal blending before the Merger, there are no Merger-related coal blending savings for the DEP coal-fired plants. DEC, however, began some coal blending activities at its Marshall Steam Plant prior to the Merger, so the Utilities have excluded a portion of these savings from the computation of Merger-related Coal Blending savings. The Coal Procurement and Coal Transportation savings result from renegotiated and new contracts that the Utilities have entered into with coal and coal transportation services providers, and thus savings originate in both Utilities.

Similarly, witness Hoard explained, the Reagent Procurement and Transportation savings amounts result from renegotiated and new contracts that the Utilities have entered into with reagent and reagent transportation services providers. The net Reagent Procurement and Transportation savings amount transferred to DEC of $110,274 is reflected as a credit to Account 502160 – Reagent Procurement Merger Savings on Schedule 2, page 1 of 2, of the Monthly Fuel Report. All of the savings related to coal and reagent procurement and transportation reported through December 31, 2012, result from contract negotiations and renegotiations with fuel supply and transportation vendors that were premised upon the Merger, but undertaken by the Utilities prior to its closing.

Witness Hoard explained that the Natural Gas Supply and Capacity savings amount is composed of savings on purchases of gas supply, pipeline capacity costs, and purchases of oil. Monthly Fuel Report Schedule 2, Account 0547123 reflects $1,946,781 for the transfer of savings from DEC to DEP.

Witness Hoard further explained that the Avoided Trading Desk savings amount is a non-fuel and fuel-related cost item that is reflected on the Monthly Fuel Report, Schedule 2, page 2 of 2, in Account 0547127. Due to the Merger, only one natural gas trading desk is needed by the Utilities. As a result, the Utilities have avoided the personnel and related costs for a second trading desk that would have been needed had the Utilities not merged. The Avoided Trading Desk savings have been counted towards the fuel savings guarantee, but do not flow through the fuel clause.

Witness Hoard testified that Company witness Smith reflected an adjustment to her EMF computation for pre-Merger savings that DEC believes should be shared with DEP. DEC has not yet reflected the transfer of these savings from DEC to DEP in fuel and fuel-related expenses. The North Carolina retail amount of these savings, which total $2,282,619, is reflected on Smith Exhibit 3, pages 1 through 4, and decreases the overcollection that Company witness Smith has reflected in the EMF computation for the test period. The computation of this amount is shown on Smith Workpaper 18. Witness Hoard notes that Company witness Smith states in her testimony, at page 12, lines 18-22, that “[U]pon approval by the Commission to adjust the overcollection for calendar year 2012 to reflect the sharing of Merger fuel-related savings achieved during the period prior to the merger close, the Company will make the appropriate entries on its books to reflect the sharing of the savings.”

Witness Hoard stated that both Utilities benefit from the Merger fuel-related savings, and the Company's proposal to share pre-Merger fuel savings between the two Utilities is consistent with the treatment of post-Merger fuel savings. Consequently, the Public Staff does not oppose this entry as long as DEP reflects the full offsetting amount in its upcoming fuel proceeding. He explained that the test period for DEP in its upcoming fuel proceeding begins April 1, 2012, so some of the pre-Merger period pre-dates the DEP test period. To ensure that ratepayers receive the full benefit of the savings, witness Hoard believes the offsetting entry made in the DEP proceeding should include savings for the January through March 2012 period that occurs prior to the beginning of the fuel proceeding test period. No party has objected to witness Hoard's recommendation for this offsetting entry.

Witness Hoard noted that the Public Staff has reviewed the tracked fuel savings computations but has not yet confirmed the validity of the amounts. He stated that the Public Staff will continue to review these fuel savings with due diligence. The Public Staff recommended that, should the Commission approve adjustments to the cumulative amount of reported fuel savings in a future proceeding, the Commission should address the accounting and ratemaking treatment of the adjustments at that time.

Based on the evidence presented, the Commission finds and concludes that DEC's proposal to share pre-merger fuel savings between itself and DEP is consistent with the treatment of post-Merger fuel savings related to the Merger and is thus reasonable and appropriate as long as DEP reflects the full offsetting amount in its upcoming fuel proceeding. In general, the cumulative amount of and accounting and ratemaking treatment of all Merger-related fuel and fuel-related cost savings shall remain subject to future Commission determination as described in the Merger Order.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence for this finding of fact is found in the testimony of Company witness Smith, the testimony of Public Staff witness Ellis, and the Stipulation.

According to the exhibits sponsored by Company witness Smith, the test period per book system sales were 79,868,568 MWh and test period per book system generation and purchased power was 86,013,644 MWh. The test period per book generation and purchased power is categorized as follows (Smith Exhibit 6, Schedules 1 and 3):

Type	MWh
Coal	27,969,376
Biomass	1,365
Oil & Combustion Turbine Gas	923,193
Combined Cycle Natural Gas	4,418,878
Nuclear	42,003,452
Hydro – Conventional	1,400,604
Hydro Pumped storage	(641,599)
Solar	10,479
Purchased Power – Economic and Dispatchable	8,093,358
Renewable Purchased Power	703,681

Other Purchased Power	907,292
Catawba Interchange	223,565
Total	86,013,644

The evidence presented regarding the operation and performance of the Company's generation facilities is discussed in the Evidence and Conclusions for Findings of Fact Nos. 5-9 and 10.

No party took issue with the portions of witness Smith's exhibits setting forth per books N.C. retail sales, generation by fuel type, and purchased power. Therefore, based on the evidence presented and noting the absence of evidence presented to the contrary, the Commission concludes that the per books levels of test period system sales of 79,868,568 MWh and system generation and purchased power of 86,013,644 MWh are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

The evidence supporting this finding of fact is found in the testimony and exhibits of Company witnesses Smith and Duncan, the testimony of Public Staff witnesses Ellis and Edwards, and the Stipulation.

Commission Rule R8-55(d)(1) provides that capacity factors for nuclear production facilities will be normalized based generally on the national average for nuclear production facilities as reflected in the most recent NERC Equipment Availability Report, adjusted to reflect the unique, inherent characteristics of the utility facilities and any unusual events. The Company proposed using a 92.84% capacity factor in this proceeding based on the operational history of the Company's nuclear units, and the number of planned outage days scheduled during the 2013-2014 billing period. According to the exhibits sponsored by Company witness Smith, utilization of this capacity factor results in Company nuclear generation (net of that retained by the Catawba Joint Owners) of 43,440,823 MWh. This proposed capacity factor exceeds the five-year industry weighted average capacity factor of 89.79% for the period 2007-2011 for pressurized water reactors rated at and above 800 MWs, as reported by NERC in its latest Generating Availability Report. Public Staff witness Ellis did not dispute the Company's proposed use of a 92.84% capacity factor.

Based upon the requirements of Commission Rule R8-55(d)(1), the historical and reasonably expected performance of the DEC system, and the fact that the Public Staff and other parties did not dispute the Company's proposed capacity factor, the Commission concludes that the 92.84% nuclear capacity factor and its associated generation of 43,440,823 MWh, which excludes the Catawba Joint Owners' portion (Smith Exhibit 2, Schedule 1, Page 1), are reasonable and appropriate for determining the appropriate fuel costs in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 15-17

The evidence supporting these findings of fact is found in the testimony and exhibits of Company witness Smith, the testimony of Public Staff witnesses Ellis and Edwards, and the Stipulation.

On Smith Exhibit 4, Company witness Smith set forth the test year per books North Carolina retail sales of 54,555,907 MWh, comprised of Residential class sales of 20,121,712 MWh, General Service/Lighting class sales of 22,116,267 MWh, and Industrial class sales of 12,317,928 MWh. Witness Smith made a decrement adjustment to per book North Carolina retail sales of (47,556) MWh for customer growth and an increment adjustment of 1,026,260 MWh for weather normalization, broken down as follows:

N.C. Retail Customer Class	Customer Growth	Weather Normalization
Residential	46,063	975,920
General Service/Lighting	(76,154)	72,533
Industrial	(17,466)	(22,193)
Total	(47,557)[1]	1,026,260

Based on these adjustments, witness Smith calculated an adjusted test year N.C. retail sales level of 55,534,611 MWh (Smith Exhibit 4,) for use in calculating the proposed EMF rates by customer class, broken down as follows and utilized as shown in Stipulation Exhibit 2:

N.C. Retail Customer Class	Adjusted kWh Sales
Residential	21,143,695
General Service/Lighting	22,112,646
Industrial	12,278,269
Total	55,534,610[2]

Witness Smith used projected billing period system sales, generation, and purchased power to calculate the proposed prospective component of the fuel rate. The projected system sales level used, as set forth on Smith Exhibit 2, Schedule 1, Page 1 is 82,388,880 MWh. The projected level of generation and purchased power used was 90,164,033 MWh (calculated using the 92.84% capacity factor found reasonable and appropriate above), and was broken down by witness Smith as follows, as set forth on that same schedule:

Type	MWh
Coal	26,277,775
Gas CT and CC	10,016,167
Nuclear	43,440,823
Hydro	1,779,845
Net Pumped Storage Hydro	(798,620)
Purchased Power	9,448,043
Total	90,164,033

Per Smith Exhibit 2, Schedule 1, Page 1, the difference of (7,775,153) MWh between projected billing period system generation and purchased power and projected billing period system sales consists of the adjustment to exclude mitigation sales of (803,900) MWh, intersystem sales of

[1] Rounding difference.
[2] Rounding difference.

(1,683,858) MWh, and line losses and Company use of (5,287,395) MWh. The total projected system fuel and fuel-related expense derived in part from the use of these generation and purchased power amounts was utilized in the Stipulation to calculate the prospective period fuel and fuel-related cost factors recommended by the Company and the Public Staff.

As part of her exhibits, Company witness Smith also presented an estimate of projected billing period N.C. retail residential, General Service/Lighting, and Industrial MWh sales (Smith Workpaper 9). According to this workpaper, the Company estimates billing period North Carolina retail MWh sales to be as follows:

N.C. Retail Customer Class	Projected MWh Sales
Residential	20,955,314
General Service/Other	22,316,250
Industrial (Including Textiles)	12,244,753
Total	55,516,317

These class totals were used in Stipulation Exhibit 1, Schedule 3 in calculating the total fuel and fuel-related cost factors by customer class, as further discussed in the Evidence and Conclusions for Findings of Fact Nos. 20 through 24.

Public Staff witness Ellis testified that he had reviewed the calculations of the various prospective fuel factor components and agreed with them. In his testimony, Public Staff witness Edwards recommended EMF decrement billing factors calculated by using the adjusted test year North Carolina retail sales level of 55,534,611 MWh and the associated adjusted MWh customer class MWh sales amounts recommended by the Company and used in the Stipulation. No other party presented any evidence challenging the amounts presented by the Company.

Based on the evidence presented by the Company, the Public Staff's agreement with the amounts presented by the Company, and noting the absence of evidence presented to the contrary, the Commission concludes that the projected and normalized levels of sales, generation, and purchased power set forth in the Company's exhibits and the Stipulation are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 18

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witnesses Smith, Culp, and Weintraub, the testimony of Public Staff witness Ellis, and the Stipulation.

Company witness Smith recommended fuel and fuel-related prices and expenses as follows:

A. The coal fuel price is $38.023/MWh.
B. The gas CT and CC fuel price is $32.554/MWh.

C. The appropriate ammonia, limestone, urea and dibasic acid (collectively, Reagents) expense is $41,840,169.

D. The total nuclear fuel price (including Catawba Joint Owners generation) is $6.759/MWh.

E. The nuclear fuel price for Catawba Joint Owners generation is $6.759/MWh.

F. The total purchased power price (including the impact of JDA Savings Shared is $36.52/MWh.

G. The adjustment to exclude the cost of mitigation sales is a reduction of $(29,839,400).

H. The adjusted level of fuel and fuel-related credits associated with intersystem sales is $(66,967,909).

These amounts are set forth on or derived from Smith Exhibit 2, Schedule 1, Page 1. The total adjusted system fuel and fuel-related expense derived in part from the use of these amounts is utilized in the Stipulation to calculate the prospective fuel factors recommended by the Company and the Public Staff.

Company witness Culp testified that the billing period price of 0.676 ¢ per kWh for nuclear fuel will be about 18% higher than experienced during the test period. Despite the higher projected nuclear fuel costs, however, those costs represent approximately 15% of system fuel costs while nuclear fuel generation represents approximately 48% of the expected system generation and purchased power mix.

Additionally, as discussed by Company witness Weintraub, the proposed fuel and fuel-related cost factors include an average delivered cost for coal for the billing period of $98.62 per ton, which is less than 1% lower than the average delivered cost of coal during the test period. In addition, witness Weintraub notes an increase in natural gas prices as evidenced by the Henry Hub forward price of $4.03 per MMBtu used in the proposed fuel rates.

Public Staff witness Ellis testified that the Public Staff determined that the projected fuel prices set forth in the Application were calculated appropriately for this proceeding. He testified that the projected cost for fuel and fuel-related costs were affected by a small projected increase in the price of natural gas as evidenced by the Henry Hub projected forward prices. In addition, nuclear fuel costs also increased from the test year. The increases in natural gas and nuclear costs are offset by a slightly lower delivered price of coal, as well as Merger fuel-related savings and joint dispatch savings.

No other party presented evidence on the level of DEC's fuel prices and expenses set forth above.

Based upon the evidence in the record as to the appropriate fuel prices and expenses, the Commission concludes that the fuel prices recommended by Company witness Smith and accepted by the Public Staff are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 19

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witnesses Smith and Weintraub, the testimony of Public Staff witness Ellis, and the Stipulation.

Consistent with G.S. 62-133.2(a2), witness Smith demonstrated that the annual increase in the aggregate amount of fuel-related expenses associated with non-capacity purchased power costs, qualifying facility capacity costs, and renewable energy costs does not exceed two percent of DEC's total North Carolina jurisdictional gross revenues for 2012. Witness Smith testified that when JDA-related costs are excluded from the purchased power calculation, the amount recoverable in the Company's proposed rates under the relevant sections of G.S. 62-133.2(a1) does not increase by more than 2% of DEC's gross revenues for its North Carolina retail jurisdiction for calendar year 2012. G.S. 62-133.2(a2) limits the amount of annual increase in certain purchased power costs identified in G.S. 62-133.2(a1) that the Company can recover to 2% of its North Carolina retail gross revenues for the preceding calendar year. In determining whether purchased power costs included in the Company's proposed rates should be limited, DEC performed its evaluation excluding the costs directly related to JDA transactions between DEC and DEP, which are providing Merger savings that the Company is passing through to its customers.

As explained by Company witness Weintraub, the JDA has allowed DEC's and DEP's generation resources to be dispatched as a single system to meet the two utilities' retail and firm wholesale customers' requirements at the lowest possible cost. The JDA was approved by the Commission in the Merger docket, and without it these specific purchased expenses between DEC and DEP would not exist. As a result, the Company has included the full amount of its purchased power costs, including these transactions, in its cost recovery application.

Smith Exhibit 2, Schedule 1, page 3 of 3 and the Stipulation provide that the projected fuel costs for the North Carolina retail jurisdiction for use in this proceeding are $1,287,001,169 (consisting of $12,302,413 of renewable and cogeneration power capacity costs, and $1,274,698,756 of other fuel costs), calculated by using the sales, generation, pricing, and other amounts addressed in the various Findings of Fact discussed in this Order. Further, the Stipulating Parties noted that the annual increase in the aggregate amount of fuel-related expenses associated with certain purchased power costs identified in G.S. 62-133.2(a1) would have exceeded two percent of DEC's total North Carolina jurisdictional gross revenues for 2012 if the JDA-related costs were not excluded from the calculation. The Stipulation acknowledges, however, that the annual increase exceeded the North Carolina jurisdictional gross revenues because the Company jointly dispatched its generation fleet with DEP, consistent with the terms of the JDA as approved by the Commission in connection with the Merger, and has saved DEC's North Carolina retail customers $5,683,604 in fuel costs since the close of the Merger on July 2, 2012. But for the operation of the JDA, the Company would not have exceeded the two percent cap.

Aside from the Company and the Public Staff, no other party presented or elicited testimony contesting the Company's projected fuel costs for the North Carolina retail jurisdiction. Based upon the evidence in the record and the absence of any direct testimony to the contrary, the Commission concludes that the Company's projected total fuel cost for the North Carolina retail jurisdiction of $1,287,001,169 is reasonable. Further, no party presented or elicited testimony contesting the Company's exclusion of the JDA-related costs from the calculation of the annual increase in the aggregate amount of the aforementioned fuel-related expenses. The Commission acknowledges that it did, in fact, approve the JDA because of the Merger savings that it will deliver – and is delivering – to customers, and that this aggregate increase is a coincidental effect of the approval of the JDA. The Commission finds, therefore, that DEC's exclusion of these costs from the calculation of the annual increase in the aggregate amount of fuel-related expenses associated with non-capacity purchased power costs is just and reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 20-24

The evidence for these findings of fact is contained in the Stipulation, the testimony and exhibits of Company witness Smith, and the testimony of Public Staff witnesses Ellis and Edwards.

Company witness Smith presented DEC's original fuel and fuel-related expense overcollection and prospective fuel cost factors. Public Staff witness Ellis testified that the prospective components of the total fuel factor have been calculated in accordance with the statute and that the Public Staff agrees with them. The Stipulation sets forth the projected fuel costs, the amount of overcollection for purposes of the EMF, the method for allocating the increase in fuel costs, the composite fuel cost factors, and the EMFs along with schedules reflecting the stipulated adjustments. Public Staff witness Edwards reviewed the revised calculation of DEC's fuel and fuel-related cost overcollection set forth in the Stipulation and agreed.

Company witness Smith calculated the Company's proposed fuel and fuel-related cost factors using a uniform bill adjustment method. The Stipulation provides that the decrease in fuel costs from the amounts approved in Docket No. E-7, Sub 1002 should be allocated between the rate classes on a uniform percentage basis, using the uniform bill adjustment methodology that was approved by the Commission in Docket No. E-7, Sub 1002. No party opposed the use of this allocation method.

Based upon the testimony and the Stipulation between the Company and the Public Staff as to the appropriate levels of sales, generation, purchased power, and unit fuel costs, as discussed in the Evidence and Conclusions for Findings of Fact Nos. 13 through 19, the Commission concludes that the prospective system fuel and fuel-related expense is $1,287,001,169 and the resulting prospective fuel and fuel-related cost factors of 2.2306¢/kWh for the Residential class, 2.3566¢/kWh for the General Service/Lighting class, and 2.3980¢/kWh for the Industrial class, excluding GRT and NCRF, are reasonable and appropriate for use in this proceeding.

G.S. 62-133.2(d) provides that the Commission "shall incorporate in its fuel cost determination under this subsection the experienced over-recovery or under-recovery of reasonable fuel expenses prudently incurred during the test period . . . in fixing an increment or decrement rider. The Commission shall use deferral accounting, and consecutive test periods, in complying with this subsection, and the over-recovery or under-recovery portion of the increment or decrement shall be reflected in rates for 12 months, notwithstanding any changes in the base fuel cost in a general rate case." The overrecovery or underrecovery portion of the fuel factor is known as the EMF.

As discussed in the Evidence and Conclusions for Findings of Fact Nos. 5-9, the Commission has concluded that the agreement between the Stipulating Parties that DEC will forgo recovery of $4,542,857 of replacement power fuel expenses incurred during the test year, as well as $757,143 of interest on that amount, for a total of $5,300,000, is appropriate and reasonable. Through the Stipulation, the Company updated its filing to reflect the impact of $431,799 of total system ($294,198 N.C. retail) fuel costs incurred in 2012 inadvertently omitted in its original filing, which represents the fuel cost component of other purchase power from a qualifying facility. Public Staff witness Edwards testified that the resulting test year North Carolina retail overrecovery amount of $51,555,143 and the related EMF interest amount of $8,592,520 are reasonable, broken down as follows:

N.C. Retail Customer Class	Test Year Overrecovery	Interest
Residential	$ 9,676,332	$1,612,721
General Service/Other	$25,992,843	$4,332,139
Industrial (Including Textiles)	$15,885,968	$2,647,660
Total	$51,555,143	$8,592,520

As a result of these amounts, Public Staff witness Edwards recommended the following EMF and EMF interest decrement billing factors:

N.C. Retail Customer Class	EMF (cents/kWh)	EMF Interest (cents/kWh)
Residential	(0.0458)	(0.0076)
General Service/Other	(0.1175)	(0.0196)
Industrial (Including Textiles)	(0.1294)	(0.0216)

These factors are also set forth in Stipulation Exhibit 1, Schedule 1.

Based upon the Stipulation between the Company and the Public Staff as to the reduction of fuel expenses, as discussed in the Evidence and Conclusions for Findings of Fact Nos. 5-9, the Commission concludes that the EMF and EMF interest decrement billing factors set forth in the testimony of Public Staff witness Edwards and in the Stipulation are reasonable and appropriate for use in this proceeding.

Accordingly, the overall fuel calculation, incorporating the conclusions reached herein, results in total net fuel and fuel-related cost factors of 2.1772¢/kWh for the Residential class, 2.2195¢/kWh for the General Service/Lighting class, and 2.2470¢/kWh for the Industrial class, excluding GRT and NCRF, consisting of the prospective, EMF, and EMF interest factors approved herein.

ELECTRIC – ADJUSTMENTS OF RATES/CHARGES

The following tables summarize the impact of the rates stipulated in this case compared with the rates approved in Docket No. E-7, Sub 1002.

Approved in the last Docket No. E-7, Sub 1002 (excluding GRT and NCRF)

Rate Class	Prospective Component	EMF Component	Total Fuel Factor
Residential	(0.1711) ¢/kWh	0.0360 ¢/kWh	(0.1351) ¢/kWh
General Service/Lighting	(0.1472) ¢/kWh	0.0323 ¢/kWh	(0.1149) ¢/kWh
Industrial	(0.1341) ¢/kWh	0.0318 ¢/kWh	(0.1023) ¢/kWh

Proposed in this Docket No. E-7, Sub 1033 (excluding GRT and NCRF)

Rate Class	Prospective Component	EMF Component	Total Fuel Factor
Residential	(0.1629) ¢/kWh	(0.0534) ¢/kWh	(0.2163) ¢/kWh
General Service/Lighting	(0.0369) ¢/kWh	(0.1371) ¢/kWh	(0.1740) ¢/kWh
Industrial	0.0045 ¢/kWh	(0.1510) ¢/kWh	(0.1465) ¢/kWh

Summary of Differences Sub 1033 – Sub 1002 (excluding GRT and NCRF)

Rate Class	Prospective Component	EMF Component	Total Fuel Factor
Residential	0.0082 ¢/kWh	(0.0894) ¢/kWh	(0.0812) ¢/kWh
General Service/Lighting	0.1103 ¢/kWh	(0.1694) ¢/kWh	(0.0591) ¢/kWh
Industrial	0.1386 ¢/kWh	(0.1828) ¢/kWh	(0.0442) ¢/kWh

Summary of Differences Sub 1033 – Sub 1002 (including GRT and NCRF[1])

Rate Class	Total Fuel Factor
Residential	(0.0840) ¢/kWh
General Service/Lighting	(0.0611) ¢/kWh
Industrial	(0.0458) ¢/kWh

[1] Based on a GRT and NCRF multiplier of 1.034554.

The Commission has carefully reviewed the Stipulation. The test period and projected fuel costs, the stipulated factors, including the EMF, and other issues addressed and resolved in the Stipulation are the result of negotiations between the Company and the Public Staff and are not opposed by any party. Therefore, based upon the evidence in this proceeding, the Commission finds and concludes that the terms of the Stipulation are fair and reasonable for the purposes of this proceeding.

IT IS, THEREFORE, ORDERED:

1. That, effective for service rendered on and after September 1, 2013, Duke Energy Carolinas shall adjust the base fuel and fuel-related costs in its North Carolina retail rates of 2.3935¢/kWh, as approved in Docket No. E-7, Sub 989, by amounts equal to (0.1629)¢/kWh, (0.0369)¢/kWh, and 0.0045¢/kWh for the Residential, General Service/Lighting and Industrial customer classes, respectively (excluding GRT and NCRF), and further, that Duke Energy Carolinas shall adjust the resultant approved fuel and fuel-related costs by decrements across the customer classes of (0.0534)¢/kWh for the Residential class, (0.1371)¢/kWh for the General Service/Lighting class, and (0.1510)¢/kWh for the Industrial class (excluding GRT and NCRF) for the EMF and EMF interest decrements. The EMF and EMF interest decrements are to remain in effect for service rendered through August 31, 2014;

2. That Duke Energy Carolinas shall file appropriate rate schedules and riders with the Commission in order to implement these approved rate adjustments, as soon as practicable, but not later than ten (10) days from the date of this Order;

3. That Duke Energy Carolinas shall work with the Public Staff to prepare a joint notice to customers of the rate changes ordered by the Commission in this docket, as well as in Docket No. E-7, Sub 1034, and the Company shall file such notice for Commission approval as soon as practicable, but not later than ten (10) days, after the Commission issues orders in both dockets; and

4. That Duke Energy Carolinas shall file an updated fuel procurement practices report in Docket No. E-100, Sub 47 that includes a natural gas hedging strategy no later than December 31, 2013.

5. That the proposal of Duke Energy Carolinas to share pre-merger fuel savings with Duke Energy Progress is hereby approved subject to the condition that Duke Energy Progress reflects the full offsetting amount of the savings in its upcoming fuel proceeding.

ISSUED BY ORDER OF THE COMMISSION.
This the 20th day of August, 2013.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

mr082013.01

Former Commissioners William T. Culpepper, III, and Lucy T. Allen, and present Commissioners Susan W. Rabon, Don M. Bailey, James G. Patterson and Jerry C. Dockham did not participate in this decision.

DOCKET NO. E-22, SUB 502

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Virginia Electric and Power Company, d/b/a Dominion North Carolina Power, for Authority to Adjust its Electric Rates Pursuant to G.S. 62-133.2 and Commission Rule R8-55	))))	ORDER APPROVING FUEL CHARGE ADJUSTMENT

HEARD: Wednesday, November 13, 2013, beginning at 9:30 a.m. in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina 27603

BEFORE: Chairman Edward S. Finley, Jr., Presiding, Commissioner Bryan E. Beatty, Commissioner Susan W. Rabon, Commissioner ToNola D. Brown-Bland, Commissioner Don M. Bailey, Commissioner Jerry C. Dockham and Commissioner James G. Patterson

APPEARANCES:

For Dominion North Carolina Power:

Mary Lynne Grigg, McGuire Woods LLP, 434 Fayetteville Street, Suite 2600, Raleigh, North Carolina 27601

Horace P. Payne, Jr., Dominion Resources Service, Inc., 120 Tredeger Street, RS-2, Richmond, Virginia 23219

For Nucor Steel-Hertford:

Phillip A. Harris, Jr., Nelson, Mullins, Riley & Scarborough, LLP, 4140 Parklake Avenue, Suite 200, Raleigh, North Carolina 27612

For the Public Staff:

Antoinette R. Wike, Chief Counsel, Public Staff-North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: On August 29, 2013, Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (Dominion North Carolina Power, DNCP, or the Company), filed its Application for Approval of its Annual Fuel Charge Adjustment, pursuant to G.S. 62-133.2 and Commission Rule R8-55 relating to fuel and fuel-related charge adjustments for electric utilities. The Application was accompanied by the testimony and exhibits of Edward J. Anderson, Harrison H. Barker, John C. Ingram, Alan L. Meekins, Bruce E. Petrie, and Gregory A. Workman.

Petitions to intervene were filed by Carolina Industrial Group for Fair Utility Rates I (CIGFUR I) and Nucor Steel-Hertford (Nucor) and were granted by Orders dated September 4, 2013, and September 13, 2013, respectively. The Public Staff's participation and intervention is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

On September 12, 2013, the Commission issued its Order Scheduling Hearing, Establishing Discovery Guidelines, and Requiring Public Notice.

On October 18, 2013, the Company filed its Affidavit of Publication. On November 4, 2013, the Public Staff filed the direct testimony of Kennie D. Ellis and the affidavit of Sonja R. Johnson. On November 7, 2013, DNCP filed the rebuttal testimony of Daniel G. Stoddard.

On November 8, 2013, DNCP and the Public Staff filed a stipulation of settlement ("Settlement Agreement") between DNCP and the Public Staff resolving all issues in this docket. On November 11, 2013, the Public Staff and DNCP filed a joint motion to excuse witnesses. On November 12, 2013, the Commission granted the joint motion to excuse witnesses.

The case came on for hearing as scheduled on November 13, 2013. At the hearing, the parties agreed to move the Application and all of the pre-filed direct testimony, supplemental testimony, and rebuttal testimony into the record without objection from any party. No public witnesses appeared at the hearing.

For the Company, the following were received into evidence: the Company's Application, direct testimony for: Edward J. Anderson, John C. Ingram, and Bruce E. Petrie; Gregory A. Workman, Harrison H. Barker, and Alan L. Meekins, and the rebuttal testimony of Daniel G. Stoddard. The Commission also received into evidence the direct testimony of Kennie D. Ellis and the affidavit of Sonja R. Johnson, both of the Public Staff. All exhibits attached to those testimonies were received into evidence. Finally, the Settlement Agreement was marked as Hearing Exhibit No. 1 and received into evidence.

Based upon the verified Application, the evidence adduced at the hearing, and the entire record in this matter, the Commission makes the following:

FINDINGS OF FACT

1. Dominion North Carolina Power is duly organized as a public utility operating under the laws of the State of North Carolina and is subject to the jurisdiction of the North Carolina Utilities Commission. The Company is engaged in the business of developing, generating, transmitting, distributing, and selling electric power to the public in northeastern North Carolina. DNCP is lawfully before this Commission based on its Application filed pursuant to G.S. 62-133.2.

2. The test period for purposes of this proceeding is the twelve months ended June 30, 2013.

3. The Company's fuel procurement and power purchasing practices during the test period were reasonable and prudent.

4. The Company's test period system sales are 81,387,056,459 kWh.

5. The test period per book system generation is 83,880,751 MWh, which includes various types of generation as follows:

Generation Types	MWh
Nuclear	28,009,282
Coal	21,126,275
Heavy Oil	136,013
Wood and Natural Gas Steam	528,895
Combined Cycle and Combustion Turbine	13,950,076
Hydro – Conventional and Pumped Storage	3,377,786
Net Power Transactions	19,948,994
Less Energy for Pumping	(3,196,569)

6. The nuclear capacity factor appropriate for use in this proceeding is 95.35%, which is the Company's estimated nuclear capacity factor for the 12 months ending December 31, 2014.

7. The adjusted test period system sales for use in this proceeding are 80,220,452,041 kWh.

8. The adjusted test period system generation for use in this proceeding is 82,657,757 MWh, which is categorized as follows:

Generation Types	MWh
Nuclear	27,970,625
Coal (including wood and natural gas steam)	21,205,270
Heavy Oil	133,190
Combined Cycle and Combustion Turbine	13,660,261
Hydro – Conventional and Pumped Storage	3,377,786
Net Power Transactions	19,507,194
Less Energy for Pumping	(3,196,569)

9. Setting the fuel costs associated with purchases from power marketers and certain other sellers at a level equal to 85% of the energy portion of the purchase price is reasonable for use in this proceeding.

10. The adjusted test period system fuel expense for use in this proceeding is $1,981,557,233.

11. The proper fuel factors for Rider A for this proceeding, including gross receipts tax (GRT), are as follows:

Customer Class	Rider A
Residential	0.044 ¢/kWh
SGS & PA	0.043 ¢/kWh
LGS	0.047 ¢/kWh
NS	0.042 ¢/kWh
6VP	0.043 ¢/kWh
Outdoor Lighting	0.044 ¢/kWh
Traffic	0.044 ¢/kWh

12. The study submitted by the Company to demonstrate that it has complied with Ordering Paragraph 1(e) of the Commission's *Order Approving Transfer with Conditions* issued April 19, 2005, in Docket No. E-22, Sub 418 (PJM Order), is reasonable for use in this proceeding.

13. The appropriate North Carolina test period jurisdictional fuel expense over-collection is $704,234 plus interest in the amount of $105,635, for a total over-collection of $809,869. The adjusted North Carolina jurisdictional test year sales are 4,269,710,243.

14. The appropriate Experience Modification Factors (EMF) for this proceeding, which incorporates interest at ten percent per annum, including gross receipts tax (GRT), are as follows:

Customer Class	EMF Billing Factor
Residential	(0.020) ¢/kWh
SGS & PA	(0.020) ¢/kWh
LGS	(0.020) ¢/kWh
NS	(0.019) ¢/kWh
6VP	(0.020) ¢/kWh
Outdoor Lighting	(0.020) ¢/kWh
Traffic	(0.020) ¢/kWh

15. The final net fuel factors (inclusive of GRT) to be billed to DNCP's retail customers during the 2014 fuel clause billing period are as follows:

Customer Class	Total Net Fuel Factor
Residential	2.561 ¢/kWh
SGS & PA	2.559 ¢/kWh
LGS	2.540 ¢/kWh
NS	2.462 ¢/kWh
6VP	2.508 ¢/kWh
Outdoor Lighting	2.561 ¢/kWh
Traffic	2.561 ¢/kWh

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

This finding of fact is essentially informational, jurisdictional, and procedural in nature and is not controverted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

General Statute 62-133.2(c) sets out the verified, annualized information that each electric utility is required to furnish the Commission in an annual fuel charge adjustment proceeding for an historical 12-month test period. Commission Rule R8-55(b) prescribes the 12 months ending June 30 as the test period for DNCP. The Company's filing was based on the 12 months ended June 30, 2013.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

The evidence for this finding of fact is contained in the direct testimony of DNCP witnesses Workman and Barker, and the testimony of Public Staff witness Ellis.

Commission Rule R8-52(b) requires each electric utility to file a Fuel Procurement Practices Report at least once every ten years and each time the utility's fuel procurement practices change. The Company's current fuel procurement practices were filed with the Commission in Docket Nos. E-100, Sub 47A on July 10, 2008, and E-22, Sub 451, on September 3, 2008. In addition, the Company files monthly reports of its fuel costs pursuant to Rule R8-52(a).

Company witness Workman described in his direct testimony the Company's fossil fuel procurement practices. He explained that the Company continues to follow the same procurement practices it has in the past. This includes the use of a rolling five-year plan for coal procurement to ensure a reliable supply of coal at competitive solicitations and secondarily on the open market, allowing the Company to layer in coal contracts of various lengths of term and market prices over a five-year period to mitigate significant price exposure for any single market period.

Company witness Workman also stated that there have not been any changes in the Company's gas procurement policies. The Company continues to procure a majority of its natural gas on the daily spot market. The Company also purchases its No. 2 fuel oil requirements on the spot market. The Company procures wood chips and wood derivative products to fuel 100% of the needs at the Pittsylvania power station.

Company witness Barker addressed in his direct testimony the nuclear fuel market and the Company's nuclear fuel procurement practices. He explained that the Company maintains a mix of longer-term front-end component contracts to reduce the near-term impact of changes in market prices, but noted that some leveling out of past increases in nuclear fuel expense rates is expected going forward.

Based on the foregoing, the Commission concludes that the Company's fuel procurement and power purchasing practices were reasonable and prudent during the test period.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4 & 5

The evidence for these findings of fact is contained in the direct testimony of DNCP witnesses Ingram and Petrie.

DNCP witness Ingram testified that the Company's test period per book system sales were 81,387,056,459 kWh, and witness Petrie testified that the Company's test period per book system generation was 83,880,751 MWh. Witness Petrie stated that the test period per book system generation is categorized as follows:

Generation Types	MWh
Nuclear	28,009,282
Coal	21,126,275
Heavy Oil	136,013
Wood and Natural Gas Steam	528,895
Combined Cycle and Combustion Turbine	13,950,076
Hydro – Conventional and Pumped Storage	3,377,786
Net Power Transactions	19,948,994
Less Energy for Pumping	(3,196,569)

No other party offered or elicited testimony on the level of test year per book system MWh sales or generation. The Commission thus concludes that the foregoing test period per books levels of sales and generation are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence for this finding of fact is contained in the direct and supplemental testimony of DNCP witness Petrie, and the testimony of Public Staff witness Ellis.

Commission Rule R8-55(d)(1) provides that capacity factors for nuclear production facilities will be normalized based generally on the national average for nuclear production facilities as reflected in the most recent North American Electric Reliability Council's (NERC) Generating Availability Report, adjusted to reflect the unique, inherent characteristics of the utility facilities and any unusual events, and may be weighted based, if appropriate, for both pressurized water reactors and boiling water reactors.

Company witness Petrie testified in his direct testimony that, for the 12 months ending December 31, 2014, North Anna Unit 1 is projected to operate at a net capacity factor of 99.8%, North Anna Unit 2 is projected to operate at a net capacity factor of 90.4%, Surry Unit 1 is projected to operate at a net capacity factor of 100.2%, and Surry Unit 2 is projected to operate a net capacity factor of 91.0%. For the nuclear fleet, the projected nuclear generation during the upcoming rate year is expected to be slightly lower than the actual generation during the test year. Based on this projection, the Company has normalized expected nuclear generation and fuel expenses in developing the proposed fuel cost rider. Public Staff witness Ellis testified that DNCP's projected fuel and fuel-related costs are based on a 95.35% nuclear capacity factor, which is what DNCP anticipates for the twelve months from January 1, 2014, through December 31, 2014, the period the new rates will be in effect.

Based on the foregoing evidence, the Commission concludes that a projected normalized system nuclear capacity factor of 95.35% is reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence for this finding of fact is contained in the direct testimony of DNCP witness Anderson, and in the testimony of Public Staff witness Ellis.

Witness Anderson testified that the Company's system sales for the twelve months ended June 30, 2013, were adjusted for changes in usage, weather normalization, and customer growth, in accordance with Commission Rule R8-55(d)(2). Witness Anderson adjusted total Company sales by 1,166,604,418 kWh. This adjustment is the sum of adjustments for changes in usage, weather normalization, and customer growth. The Public Staff reviewed and accepted these adjustments. No other party offered or elicited testimony on these adjustments.

Based on the foregoing, the Commission concludes that the adjustments for changes in usage, weather normalization, and customer growth are reasonable and appropriate adjustments for use in this proceeding. Therefore, the Company's adjusted system sales for the twelve months ended June 30, 2013, were 80,220,452,041 kWh.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence for this finding of fact is contained in the direct testimony of Company witness Petrie.

DNCP witness Petrie presented an adjustment to per book MWh generation for the 12-month period ended June 30, 2013, due to weather normalization, customer growth, and increased usage, to arrive at his adjusted generation level of 82,657,757 MWh. The Public Staff accepted this adjusted generation level, which includes various types of generation as follows:

Generation Types	MWh
Nuclear	27,970,625
Coal (including wood and natural gas steam)	21,205,270
Heavy Oil	133,190
Combined Cycle and Combustion Turbine	13,660,261
Hydro – Conventional and Pumped Storage	3,377,786
Net Power Transactions	19,507,194
Less Energy for Pumping	(3,196,569)

No other party offered or elicited testimony on the adjusted test period system generation for use in this proceeding. Thus, based on the foregoing, the Commission concludes that adjusted test period system generation level of 82,657,757 MWh is reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The evidence for this finding of fact is contained in the direct testimony of DNCP witness Ingram and the affidavit of Public Staff witness Johnson.

Company witness Ingram explained that for dispatchable non-utility generators (NUGs) that do not provide actual fuel costs, the Company continues to include 85% of the reasonable and prudent energy costs in the EMF calculation. Continued use of the 85% "marketer percentage" was agreed to between the Company and the Public Staff and approved by the Commission in the Company's 2012 fuel factor proceeding, Docket No. E-22. Sub 485. All PJM net purchases used in the EMF calculation were recorded at the 85% marketer percentage.

Public Staff witness Johnson explained that DNCP purchased power through markets administered by PJM and from two dispatchable NUGs that did not provide DNCP with the actual fuel costs associated with the purchases. As a result, a proxy marketer percentage was determined and applied to the total energy costs of the purchases. She also explained that the use of a "proxy" has been accepted by this Commission as reasonable in every fuel proceeding since 1997. Witness Johnson stated that due to the 2007 enactment of Senate Bill 3, calculation of a marketer percentage is no longer necessary for Duke Energy Carolinas, LLC, and Duke Energy Progress, Inc., however it remains necessary for DNCP, due to the treatment of the Company's purchased power expense pursuant to G.S. 62-133.2(a3). According to witness Johnson, the most current marketer percentage was approved by the Commission in the Order Granting General Rate Increase Approving Fuel Charge Adjustment, and Approving Stipulation and Supplemental Agreement (Order) issued in Docket No. E-22, Sub 479, which provided that 85% of the reasonable and prudent energy costs incurred during the fuel charge adjustment proceeding test period are to be recovered through DNCP's fuel factor. The 85% marketer percentage is to remain in effect until the sooner of DNCP's next general rate case or the fuel charge adjustment proceeding held in 2015 (with rates effective January 1, 2016). No party disputed the use of 85% in this proceeding or the use of actual fuel costs as described by the Company.

Based upon the foregoing, the Commission concludes that it is reasonable to use an 85% fuel-to-energy percentage applied to DNCP's purchases from suppliers that do not provide the Company with actual fuel costs as the proxy for actual fuel costs associated with such purchases in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 10 & 11

The evidence for these findings of fact is contained in the direct testimony of DNCP witnesses Petrie, Barker, and Anderson, and the testimony of Public Staff witness Ellis.

The Company proposed using fuel costs for the 12 months ended June 30, 2013, for all fuels. Company witness Barker testified regarding the market and components of the Company's fuel costs and how the Company's nuclear fuel expense rates are calculated. He explained that the calculation is based on expected plant operating cycles and the overall cost of nuclear fuel. Front-end component costs, along with Allowance for Funds Used During Construction (AFUDC), are amortized over the estimated energy production life of the nuclear fuel. Rear-end costs include the federal government's charge of one mill/kWh on net nuclear generation sold, which is intended to cover the eventual disposal cost of spent nuclear fuel in a federal repository. DNCP witness Barker noted that the spot price for conversion services has remained low as well, but long-term contract prices for conversion may rise due to (1) concern over the lack of investment in new conversion production facilities, (2) the possibility for shortfalls in capacity longer-term, and (3) an approximately 13-month shutdown of the only conversion facility located in the United States in order to implement new safety upgrades after the March, 2011 events in Japan.

Company witness Petrie normalized fuel expenses using a methodology approved in previous fuel rate cases. The resulting normalized system fuel expense is $1,981,557,233. The Public Staff accepted these fuel prices. No other party offered or elicited testimony on the adjusted test period system sales for use in this proceeding. Based upon the foregoing, the Commission concludes that this is the appropriate level of fuel expenses to be used to set the prospective, or forward-looking, fuel factor.

The Commission further concludes that the proper fuel factors for Rider A for use in this proceeding, including GRT, are as follows:

Customer Class	Rider A
Residential	0.044 ¢/kWh
SGS & PA	0.043 ¢/kWh
LGS	0.047 ¢/kWh
NS	0.042 ¢/kWh
6VP	0.043 ¢/kWh
Outdoor Lighting	0.044 ¢/kWh
Traffic	0.044 ¢/kWh

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence for this finding of fact is contained in the direct testimony of DNCP witness Meekins.

Company witness Meekins testified that pursuant to the PJM Order and orders in previous fuel cases, the Company prepared and submitted a study showing the impact of the Company's integration into PJM Interconnection, LLC on its North Carolina fuel clause for the 12-month period ending June 30, 2013. The results of this study show that the Company's purchase of economy energy from the PJM market was economical and beneficial compared to how the Company would have operated as a stand-alone entity. The Company has been able to purchase and import significantly more energy from the PJM market than it was historically able to do as an independent Balancing Authority.

No party offered testimony contesting the Company's PJM study or conclusions based on the study. Based on witness Meekins' testimony and in the absence of evidence to the contrary, the Commission concludes that no adjustments are necessary to comply with the PJM Order. The approach used in this proceeding, which is the same approach as has been approved in recent fuel charge adjustment proceedings, shall be used for the study DNCP is required to conduct for its fuel charge adjustment proceeding in 2014.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 13 & 14

The evidence supporting these findings of fact is contained in the direct testimony and exhibits of DNCP witnesses Anderson and Petrie, the rebuttal testimony of DNCP witness Stoddard, the direct testimony of Public Staff witness Ellis and the affidavit of Public Staff witness Johnson, and the Settlement Agreement between DNCP and the Public Staff.

DNCP witness Petrie testified that the actual system fuel expenses incurred by the Company and allocated to North Carolina jurisdictional customers totaled $1,981,557,233. DNCP witness Anderson testified that the adjusted North Carolina jurisdictional fuel clause test year sales were 4,269,710,243 kWh, and DNCP witness Ingram testified that the Company received fuel revenues totaling $106,703,666, resulting in an over-recovered fuel cost balance of $614,234, for the test year ending June 30, 2013.

Company witness Anderson proposed EMF billing factors which incorporated interest at ten percent per annum as follows:

Customer Class	EMF Billing Factor
Residential	(0.018) ¢/kWh
SGS & PA	(0.018) ¢/kWh
LGS	(0.018) ¢/kWh
NS	(0.017) ¢/kWh
6VP	(0.018) ¢/kWh
Outdoor Lighting	(0.018) ¢/kWh
Traffic	(0.018) ¢/kWh

The methodology used to develop the EMF billing factors is consistent with the methodology approved in Docket No. E-22, Sub 461 and used in the Company's 2012 fuel case, Docket No. E-22, Sub 485.

Company witness Petrie testified in his direct testimony that, for the test period of July 1, 2012 to June 30, 2013, North Anna Unit 1 performed at a net capacity factor of 103.3%. North Anna Unit 2 performed at a net capacity factor of 84.4%, Surry Unit 1 performed at a net capacity factor of 102.7%, and Surry Unit 2 performed at a net capacity factor of 92.3%. DNCP witness Petrie testified that the aggregate capacity factor of 95.6% for the Company's nuclear units during the test year was higher than the NERC five-year historical average of 88.71%.

Commission Rule R8-55(k) provides that, for purposes of determining the EMF rider, a utility must achieve either (a) an actual system-wide nuclear capacity factor in the test year that is at least equal to the national average capacity factor for nuclear production facilities based on the most recent five-year period available as reflected in the most recent NERC Generating Availability Report, appropriately weighted for size and type of plant, or (b) an average system-wide nuclear capacity factor, based upon a two-year simple average of the system-wide capacity factors actually experienced in the test year and the preceding year, that is at least equal to the national average capacity factor for nuclear production facilities based on the most recent five-year period available as reflected in the most recent NERC Generating Availability Report, appropriately weighted for size and type of plant.

Public Staff witness Ellis investigated DNCP's nuclear performance, fuel and fuel-related costs. In his testimony, witness Ellis testified that, based on the Public Staff's review, the forced outage at North Anna 2 that began on May 28, 2013, may have been preventable by DNCP under efficient management and oversight of a contract vendor's performance. Mr. Ellis recommended that the EMF factors be adjusted to remove the increased cost of replacement power due to this outage.

In his rebuttal testimony, DNCP witness Stoddard testified that the actions the Company took with respect to the circumstances that led to the outages discussed by the Public Staff were appropriate and, therefore, the Commission should not disallow any of the fuel costs incurred by DNCP during the test year.

DNCP and the Public Staff agreed to resolve all issues identified by the parties in the proceeding by reducing DNCP's EMF fuel costs by $90,000, plus interest. This agreement was memorialized by a Settlement Agreement between and among DNCP and the Public Staff, which was filed on November 8, 2013, and admitted into evidence at the hearing as Public Staff Hearing Exhibit No. 1, agreeing that the following EMF Billing Factors are reasonable.

Revised EMF Billing Factors Excluding GRT

Customer Class	Revised EMF Billing Factor
Residential	(0.019) ¢/kWh
SGS & PA	(0.019) ¢/kWh
LGS	(0.019) ¢/kWh
NS	(0.018) ¢/kWh
6VP	(0.019) ¢/kWh
Outdoor Lighting	(0.019) ¢/kWh
Traffic	(0.019) ¢/kWh

Revised EMF Billing Factors Including GRT

Customer Class	Revised EMF Billing Factor
Residential	(0.020) ¢/kWh
SGS & PA	(0.020) ¢/kWh
LGS	(0.020) ¢/kWh
NS	(0.019) ¢/kWh
6VP	(0.020) ¢/kWh
Outdoor Lighting	(0.020) ¢/kWh
Traffic	(0.020) ¢/kWh

G.S 62-133.2(d) provides in part that the Commission "shall incorporate in its fuel cost determination under this subsection the experienced over-recovery or under-recovery of reasonable fuel expenses prudently incurred during the test period . . . in fixing an increment or decrement rider. The Commission shall use deferral accounting, and consecutive test periods, in complying with this subsection, and the over-recovery or under-recovery portion of the increment or decrement shall be reflected in rates for 12 months, notwithstanding any changes in the base fuel cost in a general rate case."

The Commission concludes that DNCP over-collected its fuel expenses by $614,234 during the test year ending June 30, 2013, and that the adjusted North Carolina jurisdictional fuel clause test year sales were 4,269,710,243 kWh. The Commission believes it is reasonable to adjust the proposed EMF balance of $614,234 by $90,000, to $704,234 plus interest in the amount of $105,635, as agreed by DNCP and the Public Staff in the Settlement Agreement. Therefore, the EMF decrements agreed to in the Settlement are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The evidence supporting this finding of fact is cumulative and is contained in the direct testimony and exhibits of DNCP witnesses Anderson, Petrie, Barker, Ingram, Workman, and Meekins; the rebuttal testimony of DNCP witness Stoddard; the testimony of Public Staff witness Ellis and the affidavit of Public Staff witness Sonja Johnson; and the Settlement Agreement between and among DNCP and the Public Staff which was filed on November 8, 2013, and admitted into evidence at the hearing as Public Staff Hearing Exhibit No. 1.

Based upon the above findings and conclusions, the Commission finds and concludes that the final net fuel factors (¢/kWh) are determined as follows (inclusive of GRT):

Customer Class	Base	Rider A	Rider B	Total
NC Retail	2.508	0.044	(0.020)	2.532
Residential	2.537	0.044	(0.020)	2.561
SGS & PA	2.536	0.043	(0.020)	2.559
LGS	2.513	0.047	(0.020)	2.540
NS	2.439	0.042	(0.019)	2.462
6VP	2.485	0.043	(0.020)	2.508
Outdoor Lighting	2.537	0.044	(0.020)	2.561
Traffic	2.537	0.044	(0.020)	2.561

IT IS, THEREFORE, ORDERED as follows:

1. That the Commission hereby approves in its entirety the Settlement Agreement between and among DNCP and the Public Staff which was filed on November 8, 2013, and admitted into evidence at the hearing as Public Staff Hearing Exhibit No. 1;

2. That effective beginning with the usage on or after January 1, 2014, Dominion North Carolina Power shall implement incremental Rider A as approved and set forth in the Evidence and Conclusions for Finding of Fact No. 11 above;

3. That an EMF Rider decrement, Rider B, as approved and set forth in the Evidence and Conclusions for Finding of Fact No. 14 above, shall be instituted and remain in effect for usage from January 1, 2014, through December 31, 2014;

4. That Dominion North Carolina Power shall file appropriate rate schedules and riders with the Commission in order to implement the fuel charge adjustments approved herein not later than five working days from the date of receipt of this Order;

5. That Dominion North Carolina Power shall notify its North Carolina Retail customers of the rate adjustments approved in this proceeding by including the Notice to Customers of Rate Change attached to this Order as Appendix A as a bill insert with customer bills rendered during the next regularly scheduled billing cycle. Such Notice will appropriately provide notice of the rate changes ordered by the Commission in both this proceeding and in Docket No. E-22, Subs 494[1] and 503[2], and

6. That, with respect to the study required to determine compliance with Ordering Paragraph 1(e) of the PJM Order, Dominion North Carolina Power shall perform and file a PJM Study for the next fuel cost adjustment proceeding consistent with the PJM Study submitted in this proceeding.

ISSUED BY ORDER OF THE COMMISSION.
This, the 18th day of December, 2013.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

[1] Application by DNCP for a demand side management and energy efficiency cost recovery pursuant to G.S. 62-133.9 and Commission Rule R8-69.

[2] Application by DNCP for a Renewable Energy and Energy Efficiency Portfolio Standard adjustment pursuant to G.S. 62-133.7 and Commission Rule R8-67.

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STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-22, SUB 494
DOCKET NO. E-22, SUB 502
DOCKET NO. E-22, SUB 503

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-22, SUB 494

In the Matter of
Application by Virginia Electric and Power Company, d/b/a Dominion North Carolina Power, for Approval of Demand-Side Management and Energy Efficiency Cost Recovery Rider Pursuant to G.S. 62-133.9 and Commission Rule R8-69

DOCKET NO. E-22, SUB 502

In the Matter of
Application by Virginia Electric and Power Company, d/b/a Dominion North Carolina Power Pursuant to G.S. 62-133.2 and Commission Rule R8-55 Regarding Fuel and Fuel-Related Costs Adjustments for Electric Utilities

NOTICE TO CUSTOMERS OF CHANGE IN RATES

DOCKET NO. E-22, SUB 503

In the Matter of
Application of Virginia Electric and Power Company, d/b/a Dominion North Carolina Power for Approval of Renewable Energy and Energy Efficiency Portfolio Standard Cost Rider Pursuant to G.S. 62-133.8 and Commission Rule 8-67

NOTICE IS HEREBY GIVEN that, as required by legislation passed in 2007 by the North Carolina General Assembly, the North Carolina Utilities Commission has authorized Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (DNCP or Company), to adjust its rates to recover its costs of purchasing renewable energy, its costs of fuel and fuel-related costs, and its costs associated with programs

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implemented to encourage more efficient use of electricity by its customers. The Commission's Orders were issued on December 18, 2013, in Docket No. E-22, Subs 503, 502 and 494. These rate adjustments will become effective for usage on and after January 1, 2014.

Renewable Energy and Energy Efficiency Portfolio Standard Rate Increase

The Commission approved DNCP's proposed new Riders RP and RPE designed to recover $1,677,392 associated with its annual obligation to purchase electricity produced by renewable energy resources under North Carolina's Renewable Energy and Energy Efficiency Portfolio Standard (REPS). The rate increase was approved by the Commission after review of DNCP's incremental REPS compliance costs incurred during the period January 1, 2012 through June 30, 2013, and costs projected to be incurred during calendar year 2014. The combined Rider RP and Rider RPE charges result in the following monthly per-account customer charges for usage during calendar year 2014: Residential - $0.37; Commercial - $5.33; and Industrial - $35.93. As approved, DNCP's renewable energy cost recovery rider is not applicable to agreements under the Company's outdoor lighting rate schedules, nor for sub-metered service agreements. Additionally, the REPS rider is not applicable to small auxiliary separately metered services provided to a customer on the same property as a residential or other service account. An auxiliary service is defined as a non-demand metered, nonresidential service provided on schedule SGS or SG, at the same premises, with the same service address, and with the same account names as an agreement for which a monthly REPS charge has been applied. To qualify for an auxiliary service, not subject to this rider, the customer must notify the Company and the Company must verify that such agreement is considered an auxiliary service, after which the REPS billing factor will not be applied to qualifying auxiliary service agreements. The customer shall also be responsible for notifying the Company of any change in service that would no longer qualify the service as auxiliary. Please contact the Company at 1-866-DOM-HELP or 1-866-366-4357, or go to *https://www.dom.com/REPS-opt-out* for additional detail on qualifying as an eligible auxiliary service account.

Fuel-Related Rate Increase

The Commission approved a $4,899,151 aggregate increase in DNCP's annual fuel revenues. The rate increase was approved by the Commission after review of the Company's fuel expenses during the 12-month period ended June 30, 2013, and represents changes experienced and expected by the Company with respect to its reasonable costs of fuel and the fuel component of purchased power. DNCP's total net fuel factors for each customer class to be billed during calendar year 2014 are: Residential - 2.561 ¢/kilowatt hour (kWh); SGS & Public Authority - 2.559 ¢/kWh; LGS - 2.540 ¢/kWh; NS - 2.462 ¢/kWh; 6VP - 2.508 ¢/kWh; Outdoor Lighting - 2.561¢/kWh; and Traffic - 2.561 ¢/kWh. The foregoing rates are the result of the

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Commission's approval of a Stipulation of Settlement agreed to by DNCP and the Public Staff – North Carolina Utilities Commission in this proceeding.

Demand-Side Management and Energy Efficiency Related Rate Increase

The Commission approved a $466,930 aggregate increase in DNCP's annual demand-side management and energy efficiency (DSM/EE) program revenues. The rate increase was approved by the Commission after review of the Company's forecasted DSM/EE program expenses and utility incentives for the calendar year 2014 (Rider C) and its true up of its actual costs and revenues received under Rider C rates in effect during the twelve months ending June 30, 2013 (Rider CE). The combined Rider C and Rider CE rates result in the following kWh charges for usage during calendar year 2014: Residential - 0.092 ¢/kWh; SGS & Public Authority - 0.084 ¢/kWh; LGS - 0.106 ¢/kWh; 6VP - 0.091 ¢/kWh; no charge for NS, Outdoor Lighting and Traffic. Commercial customers with annual consumption of 1,000,000 kWh or greater in the prior calendar year, and all industrial customers, may elect not to participate in the Company's DSM/EE programs and thereby avoid paying these charges by notifying the Company that they have implemented or will implement their own DSM or EE measures. Commercial and industrial customers choosing this option will receive an offsetting credit to the DSM/EE rates on their monthly bills. Please go to https://www.dom.com/dominion-north-carolina-power/customer-service/energy- conservation/north-carolina-dsm-commercial-opt-out.jsp for additional details on DSM/EE opt out eligibility.

Summary of Rate Increases

Each of these rate changes will become effective for usage on and after January 1, 2014. The total monthly impact of these rate changes for a residential customer using 1,000 kWh per month is an increase of $1.53, which is approximately a 1.4% increase. The total monthly impact for commercial and industrial customers will vary based upon consumption and customers' participation in the Company's DSM/EE programs.

ISSUED BY ORDER OF THE COMMISSION.
This the 18th day of December, 2013.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

DOCKET NO. E-7, SUB 1014

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Carolinas, LLC for	)	ORDER ACCEPTING COMPLIANCE
Approval of Vegetation Management Program	)	FILINGS AND REQUIRING FILING
	)	OF RELIABILITY DATA

BY THE COMMISSION: On October 8, 2012, the Commission issued an Order Approving Customer Materials, And Requiring Additional Information, in the above-captioned docket. That Order required Duke Energy Carolinas, LLC (Duke), to clarify its vegetation management practices and update its related customer communication materials. On November 26, 2012, Duke made the required compliance filing.

On April 19, 2013, the Commission issued an Order Requiring Response to Consumer Statements. That Order required Duke to file a detailed response to nine consumer statements related to the Company's tree trimming practices in the Greensboro area. On May 24, 2013, Duke filed the required responses.

On April 30, 2013, Duke filed a supplement to its Vegetation Management Plan and Policies (VMPP) entitled, "Old Design Urban Circuits: Proposed Operational Pruning Practices for Routine Distribution Maintenance." The Company stated that it had determined that it could revise its VMPP for overhead distribution lines that operate at 4 kilovolts (kV) and 12 kV because such lines are less sensitive to vegetation and therefore the Company can be more flexible regarding trimming and removing trees that are near these lines. Duke proposed to revise its VMPP by inserting the proposed supplement to its policy as a new subsection, and then re-filing the revised VMPP with the Commission.

The Commission has carefully reviewed Duke's submittals, including its proposed VMPP revisions, its proposed VMPP supplement, and its responses regarding the consumer statements.

The Commission finds that the proposed VMPP revisions are appropriate in that they help insure that Duke's vegetation management policies and practices are consistent and clearly communicated to the public. The Commission further finds that Duke's proposed supplement to its VMPP is appropriate at this time, but has the potential to result in a higher number of service outages. Therefore, the Commission will require Duke to track and report tree-related outages for circuits that are subject to the supplemental policy and report its findings as an addendum to the reports it will be required to file pursuant to the Commission's pending order in Docket No. E-100, Sub 138[1].

[1] Rulemaking Proceeding to Standardize the Indices Used to Measure and Report Electric Utility Service Quality.

IT IS, THEREFORE, ORDERED as follows:

1. That Duke shall revise its VMPP to include the changes that it has submitted, including the supplement, and re-file it with the Commission within 30 days;

2. That Duke shall revise its customer communication materials consistent with its updated VMPP as soon as practicable; and

3. That Duke shall track tree-related outages on circuits subject to the VMPP supplement and file the outage data with the reports it will be required to submit pursuant to the Commission's pending order in Docket No. E-100, Sub 138.

ISSUED BY ORDER OF THE COMMISSION.
This the 3rd day of June, 2013.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

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DOCKET NO. E-7, SUB 1034

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Duke Energy Carolinas, LLC, for Approval of Renewable Energy and Energy Efficiency Portfolio Standard Cost Recovery Rider Pursuant to G.S. 62-133.8 and Commission Rule R8-67	)	ORDER APPROVING REPS AND REPS EMF RIDERS AND 2012 REPS COMPLIANCE

HEARD: Tuesday, June 4, 2013, at 9:30 a.m. in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner Bryan E. Beatty, Presiding, Chairman Edward S. Finley, Jr., and Commissioners William T. Culpepper, III, ToNola D. Brown-Bland, and Lucy T. Allen

APPEARANCES:

For Duke Energy Carolinas, LLC:

Robert W. Kaylor, Law Office of Robert W. Kaylor, P.A., 353 Six Forks Road, Suite 260, Raleigh, North Carolina 27609

Kendrick C. Fentress, Associate General Counsel, Duke Energy, PEB 20/Post Office Box 1551, Raleigh, North Carolina 27602

For the North Carolina Waste Awareness and Reduction Network:

John E. Runkle, 2121 Damascus Church Road, Chapel Hill, North Carolina 27516

For the North Carolina Sustainable Energy Association:

Michael D. Youth, Post Office Box 6465, Raleigh, North Carolina 27628

For the Using and Consuming Public:

Robert S. Gillam and Tim R. Dodge, Staff Attorneys, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: On March 4, 2013, Duke Energy Carolinas, LLC (DEC or the Company) filed a motion for extension of time to file its 2012 REPS compliance report and application for cost recovery. On March 4, 2013, the Commission issued an Order Granting

Extension of Time to File Application, allowing the Company until March 13, 2013, to file its 2012 REPS compliance report and application for cost recovery.

On March 13, 2013, DEC filed its 2012 REPS compliance report and application seeking an adjustment to its North Carolina retail rates and charges pursuant to G.S. 62-133.8(h) and Commission Rule R8-67, which require the Commission to conduct an annual proceeding for the purpose of determining whether a rider should be established to permit the recovery of the incremental costs incurred to comply with the requirements of the Renewable Energy and Energy Efficiency Portfolio Standard (REPS), G.S. 62-133.8(b), (d), (e) and (f), and to true-up any under-recovery or over-recovery of compliance costs. DEC's application was accompanied by the testimony and exhibits of Jonathan Byrd, Renewable Strategy and Compliance Manager - Carolinas, and Veronica Williams, Rates Manager – Duke Energy Carolinas. In its application and pre-filed testimony, DEC sought approval of its proposed REPS rider and REPS EMF rider.

On March 22, 2013, the Commission issued an Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines and Requiring Public Notice. The Order set this matter for hearing, established deadlines for the submission of intervention petitions, intervenor testimony and DEC rebuttal testimony, required the provision of appropriate public notice, and established discovery guidelines.

Petitions to intervene were filed by North Carolina Sustainable Energy Association (NCSEA), Carolina Utility Customers Association, Inc. (CUCA), and the North Carolina Waste Awareness and Reduction Network (NC WARN). Each of these petitions to intervene was allowed by the Commission. The intervention and participation by the Public Staff are recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

On May 3, 2013, DEC filed the supplemental testimony and supporting exhibits of witnesses Williams and Byrd. On May 20, 2013, the Public Staff filed the testimony and exhibits of Jay Lucas, Engineer – Electric Division, and the confidential testimony and exhibits of Catherine Eastwood, Staff Accountant – Accounting Division. The Public Staff subsequently filed witness Eastwood's amended confidential testimony on May 24, 2013.

On May 23, 2013, DEC filed affidavits of publication indicating that public notice had been provided in accordance with the Commission's procedural order.

On May 29, 2013, DEC filed the rebuttal testimony and exhibits of witness Williams, and on May 30, 2013, DEC filed a motion for its witnesses to appear as a panel at the hearing. On May 31, 2013, the Public Staff filed a motion for its witnesses to appear as a panel at the hearing.

The matter came on for hearing on June 4, 2013. Duke presented the testimony and exhibits of witnesses Byrd and Williams, and the Public Staff presented the testimony and exhibits of witnesses Lucas and Eastwood.

On July 2, 2013, the Company filed a letter in response to a question posed by Commissioner Beatty at the hearing regarding the tracking of renewable energy certificates (RECs) by Duke Energy Progress, Inc. (f/k/a Progress Energy Carolinas, Inc.).

On July 12, 2013, DEC and the Public Staff each filed a proposed order, and NCSEA filed a post-hearing brief. On July 22, 2013, DEC filed a motion requesting leave to file a reply brief, as well as a reply brief, and a revised Byrd Exhibit No. 2. Also on July 22, 2013, NCSEA filed a response to Duke's motion. On July 23, 2013, the Commission issued an Order granting Duke's motion to file a reply brief.

Based upon the foregoing, the testimony and exhibits introduced at the hearing, DEC's records in the North Carolina Renewable Energy Tracking System (NC-RETS), and the entire record in this proceeding, the Commission now makes the following:

FINDINGS OF FACT

1. DEC is duly organized as a public utility company under the laws of the State of North Carolina and is subject to the jurisdiction of this Commission. DEC is engaged in the business of generating, transmitting, distributing, and selling electric power to the public in North Carolina. DEC is also an electric power supplier as defined in G.S. 62-133.8(a)(3). DEC is lawfully before this Commission based upon its application filed pursuant to G.S. 62-133.8 and Commission Rule R8-67.

2. Under the State's REPS, G.S. 62-133.8, in 2012 electric power suppliers were required to meet 3 percent of their previous year's North Carolina retail electric sales by a combination of renewable energy and energy reductions due to the implementation of energy efficiency (EE) measures. In addition, by the end of 2012 electric power suppliers must have acquired solar energy, or renewable energy certificates (RECs) for solar power, in an amount equal to at least 0.07 percent of the previous year's North Carolina retail sales. The sources can be a combination of new solar electric facilities and new metered solar thermal energy facilities. The electric power suppliers of North Carolina were initially required by G.S. 62-133.8 to procure a certain portion of their renewable energy requirements beginning in 2012 from electricity generated by poultry and swine waste. However, in the Commission's November 29, 2012 Order in Docket No. E-100, Sub 113, the 2012 requirement relative to swine waste resources was eliminated, and the 2012 requirement relative to poultry waste resources was delayed for one year. DEC has stated that it will not meet its 2013 swine and poultry waste resource obligations, but has not yet requested that the Commission modify or delay those obligations.

3. G.S. 62-133.8(h)(4) provides that an electric power supplier shall be allowed to recover through an annual rider the incremental costs incurred to comply with the REPS.

4. Under Commission Rule R8-67(e)(2), the total costs reasonably and prudently incurred during the test period to purchase unbundled RECs constitute incremental costs. The projected costs to purchase such RECs during the billing period constitute forecasted incremental costs.

5. DEC has agreed to provide REPS compliance services, including the procurement of RECs, to the following electric power suppliers pursuant to G.S. 62-133.8(c)(2)(e): Blue

Ridge Electric Membership Corporation (EMC), the City of Concord, the Town of Dallas, the Town of Forest City, the City of Highlands, the City of Kings Mountain, and Rutherford EMC.

6. DEC and the seven electric power suppliers to which DEC is providing compliance services met their 2012 REPS obligations, except for those from which they had been relieved under the Commission's Order of November 29, 2012, in Docket No. E-100, Sub 113. DEC's 2012 REPS compliance report should be approved.

7. For purposes of DEC's annual rider pursuant to G.S. 62-133.8(h), the test period and billing period for this proceeding are, respectively, the calendar year 2012 and the 12-month period ending August 31, 2014.

8. The research activities funded by DEC during the test period and planned for the billing period are renewable research costs recoverable under G.S. 62-133.8(h)(1)b. The research costs are within the statute's $1-million annual limit. It is appropriate for DEC to provide, in its 2014 REPS rider application, the results of its REPS-related research when these results are publicly available, and the procedures for third parties to access the results, when they are proprietary. For research projects sponsored by the Electric Power Research Institute (EPRI), DEC should provide the overall program number and specific project number for each project, as well as an internet address or mailing address that will enable third parties to inquire about the terms and conditions for access to any portions of the study results that are proprietary. A study to determine whether those large customers that have opted-out of DEC's DSM and EE programs have pursued their own DSM and EE measures would qualify for cost recovery under G.S. 62-133.8(h)(1)b.

9. It is not reasonable for DEC to recover all of the unrecovered costs of its internal REC tracking system from its North Carolina retail customers. Therefore, DEC shall be required to remove 19 percent of these costs from its proposed EMF rider and reverse its proposed inclusion of those costs that had initially been allocated to its Ohio subsidiaries.

10. For purposes of establishing the REPS EMF rider in this proceeding, DEC's incremental costs of REPS compliance during the test period were $9,670,191. DEC's North Carolina retail test period REPS expense over-collections, including interest, were $4,433,698, $211,011, and $461,026 for the residential, general service, and industrial customer classes respectively, excluding interest, gross receipts tax and regulatory fee.

11. DEC's North Carolina retail prospective billing period expenses for use in this proceeding are $3,750,115, $8,695,138, and $1,102,011 for the residential, general service, and industrial customer classes respectively, excluding gross receipts tax and the regulatory fee.

12. The appropriate monthly amount of the REPS EMF rider per customer account, including interest but excluding gross receipts tax and the regulatory fee, to be collected during the billing period is ($0.23) for residential accounts, ($0.08) for general service accounts, and ($7.71) for industrial accounts.

13. The appropriate monthly amount of the REPS rider per customer account, excluding gross receipts tax and the regulatory fee, to be collected during the billing period is $0.19 for residential accounts, $3.22 for general service accounts, and $18.44 for industrial accounts.

14. The combined monthly REPs and REPS EMF rider charges per customer account, excluding gross receipts tax and the regulatory fee, to be collected during the billing period are ($0.04) for residential accounts, $3.14 for general service accounts, and $10.73 for industrial accounts.

15. DEC's REPS incremental cost riders to be charged to each customer account for the billing period are within the annual cost caps established in G.S. 62-133.8(h)(4).

16. DEC's method of tracking energy efficiency certificates (EECs) is appropriate for this proceeding. However, it is appropriate for DEC to provide additional EEC tracking information in future REPS proceedings. It is appropriate for DEC and the Public Staff to continue discussing the most effective way to track EECs.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-5

These findings of fact are essentially informational, jurisdictional, and procedural in nature and are not contested.

G.S. 62-133.8(b)(1) and (c)(1) establish a REPS requirement for all electric power suppliers in the State. These provisions require each electric power supplier to provide a certain percentage of its North Carolina sales from various renewable energy or EE resources. Authorized methods of compliance with the REPS requirement for electric public utilities are listed in G.S. 62-133.8(b)(2) as follows: (a) generate electric power at a new renewable energy facility; (b) use a renewable energy resource to generate electric power at a generating facility other than the generation of electric power from waste heat derived from the combustion of fossil fuel; (c) reduce energy consumption through the implementation of an energy efficiency measure; (d) purchase electric power from a new renewable energy facility; (e) purchase renewable energy certificates derived from in-State or out-of-state new renewable energy facilities; (f) use electric power that is supplied by a new renewable energy facility or energy saved due to the implementation of an energy efficiency measure that exceeds the requirements of this section for any calendar year as a credit towards the requirements of this section in the following calendar year; or (g) electricity demand reduction.

Each of these compliance methods is subject to certain additional limitations and conditions. G.S. 62-133.8(c) has similar requirements for EMCs and municipal electric systems. In 2012, the electric public utilities were required generally to meet 3 percent of their previous year's North Carolina retail electric sales by a combination of the measures authorized by G.S. 62-133.8(b).

G.S. 62-133.8(d) requires a certain percentage of the total electric power sold to retail electric customers in the State, or an equivalent amount of energy, to be supplied by a combination of new solar electric facilities and new metered solar thermal energy facilities. The percentage requirement for solar resources is 0.07 percent for the years 2012 through 2014.

G.S. 62-133.8(e) requires a certain percentage of the total electric power sold to retail electric customers in the State to be supplied, or contracted for supply each year, by swine waste resources. In 2012, the aggregate requirement for swine waste resources was 0.07 percent. G.S. 62-133.8(f) requires a specific amount of electric power sold to retail electric customers in the State to be supplied, or contracted for supply each year, by poultry waste resources. In 2012, the aggregate requirement for poultry waste resources was 170,000 megawatt-hours (MWh). Pursuant to the Commission's Order on Pro-Rata Allocation of Aggregate Swine and Poultry Waste Set-Aside Requirements and Motion for Clarification, issued on March 31, 2010, in Docket No. E-100, Sub 113, DEC's share of the aggregate State set-aside requirements for energy from swine and poultry waste resources is based on the ratio of its North Carolina retail kilowatt-hour (kWh) sales from the previous year divided by the previous year's total North Carolina retail kWh sales for all electric power suppliers. However, in an Order Modifying the Poultry and Swine Waste Set-Aside Requirements and Granting Other Relief, issued on November 29, 2012, in Docket No. E-100, Sub 113, the Commission found that because of the immaturity of the technology of power production from swine and poultry waste resources, and for a variety of other reasons, most of the State's electric power suppliers would be unable to comply with the swine and poultry waste resource set-aside requirements for 2012, despite having made a reasonable effort to comply. The Commission directed, pursuant to G.S. 62-133.8(i)(2), that the swine waste resource set-aside requirement for 2012 be eliminated, and that the poultry waste resource requirements for 2012 and 2013 be delayed for a year, so that the aggregate statewide poultry waste resource requirement would be 170,000 MWh rather than 700,000 MWh for 2013, and 700,000 MWh rather than 900,000 MWh for 2014.

G.S. 62-133.8(h)(4) requires the Commission to allow an electric power supplier to recover all of its incremental costs incurred to comply with G.S. 62-133.8 through an annual rider. G.S. 62-133.8(h)(1) provides that "incremental costs" means all reasonable and prudent costs incurred by an electric power supplier to comply with the REPS requirements that are in excess of the electric power supplier's avoided costs, other than those costs recovered pursuant to G.S. 62-133.9. The term "avoided costs" includes both avoided energy costs and avoided capacity costs.

Commission Rule R8-67(e)(5) provides that "[t]he REPS EMF will reflect the difference between reasonable and prudently incurred incremental costs and the revenues that were actually realized during the test period under the REPS rider then in effect."

DEC's 2012 REPS compliance report stated that pursuant to G.S. 62-133.8(c)(2)e the Company provided renewable energy resources and compliance reporting services for Blue Ridge EMC, the City of Concord, the Town of Dallas, the Town of Forest City, the City of Highlands, the City of Kings Mountain, and Rutherford EMC.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence supporting this finding of fact appears in DEC's 2012 REPS compliance report and in the testimony of DEC witness Byrd and Public Staff witness Lucas. In addition, the Commission takes judicial notice of information contained in NC-RETS.

DEC's 2012 REPS compliance report was admitted into evidence as Byrd Exhibit No. 1. This report provides the information required by Commission Rule R8-67(c) in aggregate for DEC and the wholesale customers for which DEC has agreed to provide REPS compliance services. Public Staff witness Lucas testified that he had reviewed the compliance report and recommended that it be approved.

DEC's 2012 REPS compliance report stated that the combined 2011 retail electric sales for DEC and the seven wholesale customers for which DEC provided compliance services was 59,462,811 MWh; hence, the related 2012 REPS obligations amounted to 1,783,884 RECs (3 percent of 59,462,811), including 41,624 solar RECs (0.07 percent of 59,462,811). Public Staff witness Lucas testified that these numbers of RECs met the REPS requirements that 3 percent of 2011 retail sales must be matched with an equivalent number of RECs in 2012, including 0.07 percent of 2011 retail sales that must be matched with an equivalent number of RECs derived from solar energy.

Witness Lucas testified that in addition to the solar RECs that DEC placed into its compliance sub-account in NC-RETS to satisfy its solar set-aside obligation, DEC also used 11,194 solar RECs to meet its general requirement, and this was appropriate in light of the fact that solar RECs are currently available at prices comparable to those of other general RECs. DEC witness Byrd likewise noted that DEC had retired 11,194 in-state solar RECs beyond those required for the solar set-aside, and that this did not increase costs for customers, since current prices for solar RECs are in the range of prices for other general RECs.

According to the records in NC-RETS, DEC correctly transferred a total of 1,783,889 RECs[1] into eight NC-RETS compliance sub-accounts, with one of these sub-accounts earmarked toward DEC's 2012 general requirement obligation and the others toward each of the seven wholesale customers' obligations. Among these 1,783,889 RECs were 52,823 solar RECs, including the 11,194 solar RECs used for general compliance. NC-RETS further indicates that DEC complied with the provisions of G.S. 62-133.8(b)(2)e and (c)(2)d that out-of-state RECs may not be used to meet more than 25 percent of an electric power supplier's REPS requirements. No parties disputed that DEC and the wholesale customers complied with their 2012 REPS requirements, and witnesses Byrd and Lucas both stated that DEC and the seven wholesale customers had met the 2012 REPS requirements.

[1] Witness Lucas testified that DEC placed 1,783,889 RECs in its compliance sub-account and those of its wholesale customers, rather than 1,783,884, because "its use of several sources of RECs frequently requires rounding up to the next whole REC." In addition, the Commission understands that because any given electric power supplier must comply via a given number of "whole" RECs (a fraction of a REC is not permitted), an aggregated group of suppliers will seemingly "over-comply" by several RECs.

Therefore, the Commission finds that DEC and the seven wholesale customers for which it is providing REPS compliance services have fully complied with the requirements of the REPS for 2012, and that DEC's 2012 REPS compliance report should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

This finding of fact is essentially informational, jurisdictional, and procedural in nature and is not controversial.

Commission Rule R8-67(e)(3) provides that the test period for REPS rider proceedings shall be the same as that used by the utility in its annual fuel charge adjustment proceedings, which is specified in Rule R8-55(c) for DEC to be the calendar year. Therefore, DEC proposed that the test period for its REPS cost recovery proceeding be the calendar year 2012.

Rule R8-67(e)(4) provides that the REPS and REPS EMF riders shall be in effect for a fixed period that "shall coincide, to the extent practical, with the recovery period for the cost of fuel and fuel-related cost rider established pursuant to Rule R8-55." In its current fuel proceeding, Docket No. E-7, Sub 1033, and in this proceeding, DEC has proposed that its rate adjustments take effect on September 1, 2013, and remain in effect for a 12-month period. This period is the "billing period."

The test period and billing period proposed by DEC were not challenged by any party. Therefore, the Commission finds that the test period and billing period appropriate for this proceeding are the calendar year 2012 and the twelve months ending August 31, 2014, respectively.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence supporting this finding of fact appears in the testimony and exhibits of DEC witnesses Byrd and Williams and Public Staff witness Lucas.

Pursuant to G.S. 62-133.8(h)(1), "incremental costs" include, among other things, "all reasonable and prudent costs incurred by an electric power supplier to . . . (b) (F)und research that encourages the development of renewable energy, energy efficiency, or improved air quality, provided those costs do not exceed one million dollars ($1,000,000) per year." Whether specific test period expenditures to fund research are eligible for cost recovery through an annual rider pursuant to this provision is determined by the Commission on a case-by-case basis.

In compliance with the Commission's Order Approving REPS and REPS EMF Riders and 2011 REPS Compliance[1], witness Byrd supplied testimony and exhibits on the results and status of various studies for which DEC sought cost recovery in this proceeding. The Company provided the following information:

1. DEC partnered with Duke University to study the potential in North Carolina for injection of swine biogas into interstate pipelines with subsequent centralized

[1] Order dated August 16, 2012, in Docket No. E-7, Sub 1008.

electricity generation. This research provides insight into the relative economics of directed swine biogas compared to individual on-farm projects. The study results are final and have been public as of April 25, 2013.

2. The Company partnered with Duke University to develop a pilot-scale, sixty-five kilowatt swine waste-to-energy facility, which began producing renewable energy in 2011. Byrd Exhibit No. 3 summarized the project's progress through August 31, 2012.
3. The Company commissioned the Energy Production and Infrastructure Center at the University of North Carolina -- Charlotte to conduct a static and dynamic modeling analysis of two electric distribution circuits. The objective of this analysis was to identify operational impacts that a distribution circuit is likely to experience when a high penetration of solar generation is connected. The Company submitted a summary of the findings from this analysis as Byrd Exhibit No. 4.
4. The Company commissioned the University of North Carolina to analyze wind resources outside the barrier islands where potential may exist for large scale off-shore wind projects. The study is ongoing and Byrd Exhibit No. 5 detailed the progress through April 2012.
5. The Company continued to support a closed-loop biomass research project to better understand yield potential for various woody and herbaceous crops, including loblolly pine and miscanthus grass. American Forest Management provides project management support and periodically updates the Company, as shown in Byrd Exhibit No. 6.
6. The Company subscribes to various EPRI programs, including Wind, Solar, Biomass, and Renewable Energy Economics and Technology Status. EPRI designates such study results as proprietary or as trade secrets, licensing such results to EPRI members, including the Company. As such, DEC may not disclose the information publicly. Non-members may access these studies for a fee.
7. The Company subscribes to Bloomberg New Energy Finance REC Market Insights Service, which provides access to renewable energy news and REC market analyses, including price and supply/demand trends for REC markets across the United States. Bloomberg designates the study results as proprietary or as trade secrets, and licenses such reports to subscribers, including the Company. As such, DEC may not disclose the information publicly. Interested parties can obtain copies of these reports via Bloomberg subscription. Non-members may access this service for a fee.

Witness Byrd confirmed on cross-examination that DEC would be willing to continue to file study results for any studies the cost of which it has recovered through the REPS rider. Witness Byrd also testified that DEC subscribed to many programs with EPRI, although some were paid for or managed out of the power delivery organization and not the renewable organization. Witness Byrd also confirmed on cross-examination that DEC would be willing to provide, upon request, the specific EPRI programs that DEC is participating in or subscribing to for programs that are recovered under REPS. DEC would also be willing to make the information available in the report, as opposed to direct testimony, for members of the public to review. DEC would be unable to provide information about the cost of EPRI studies to "persons [who] may want to consider purchasing specific study results," because those persons would have to contact EPRI directly. However, the Company would provide contact information generally.

The amount of DEC's research expenses was provided in witness Williams' confidential exhibits and is below the statutory limit of $1 million per year. Neither the Public Staff nor any other intervenor took issue with DEC's testimony concerning the nature and costs of its research activities.

During the hearing, witness Lucas was asked whether the cost of research regarding the EE activities of customers that have opted-out of DEC's EE programs could be recovered via the REPS rider. Witness Lucas replied in the affirmative, stating, "I believe that can be covered under the million dollar per year allowed research allotment in G.S. 62-133.8."

In its post-hearing brief, NCSEA sought to have the Commission require DEC to report on REPS-related research in its annual REPS rider application, "even if DEC chooses to seek cost recovery for the research elsewhere." NCSEA asserted that this reporting requirement would make more information public and thereby improve customer confidence in DEC's REPS expenditures and potentially prompt innovations and reductions in the cost of REPS compliance. In its reply brief, DEC objected to NCSEA's proposal, arguing that such information was not necessary for the Commission to review the Company's REPS costs and compliance. DEC stated that NCSEA's proposal could potentially require DEC to: (1) determine annually all of the studies or research in which the Company is involved; (2) determine if the identified research were primarily focused on renewable energy, energy efficiency or improved air quality; (3) determine the confidentially of the information and possibly the project numbers and contact information; and (4) provide testimony and possibly respond to data requests about the research.

The Commission finds that NCSEA's proposal would potentially be burdensome and is not necessary to the administration of REPS. Therefore, the Commission declines to adopt NCSEA's proposal.

The Commission concludes that the research activities funded by DEC during the test period are renewable research and development costs recoverable under G.S. 62-133.8(h)(1)(b), and that such research costs included in the test period are within the $1 million annual limit provide in that statute. Additionally, the Commission finds that DEC has agreed to provide the specific EPRI programs that DEC is participating in or subscribing to for programs that are recovered under REPS and, to the extent that a public web address for an EPRI program description is available, DEC would also be willing to make the information available in its REPS compliance report, as opposed to in its direct testimony, for members of the public to review. The Commission concludes that the scope of this reporting requirement is reasonable and appropriate.

Finally, the Commission agrees with witness Lucas that the cost of research regarding the EE activities of customers that opt-out of DEC's EE programs is recoverable via the REPS rider. The Commission will address whether and how such research should be pursued in DEC's DSM/EE rider proceeding (Docket No. E-7, Sub 1031).

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The evidence for this finding of fact appears in the testimony of DEC witnesses Byrd and Williams, and the testimony and exhibits of Public Staff witnesses Eastwood and Lucas.

DEC witnesses Byrd and Williams testified that after the enactment of G.S. 62-133.8, DEC determined that in order to meet the compliance requirements of the REPS and the cost recovery and reporting obligations of Commission Rule R8-67, the Company needed a computerized system to track the quantity and cost of RECs held in its inventory. According to the Company, the volume of these activities was large, and the activities were sufficiently complex that tracking them through an Excel spreadsheet was not practical or efficient. DEC therefore contracted with an affiliate, Duke Energy Business Services (DEBS), for DEBS to develop a REC tracking system. DEC has designated the cost of the REC tracking system as a confidential trade secret, and no party challenged that designation.

It was initially intended that DEC's Ohio affiliates, Duke Energy Ohio (DEO) and Duke Energy Retail Services (DERS), would also use the tracking system to manage compliance with the Ohio Alternative Energy Portfolio Standard, and would therefore share 19 percent of the cost. In March 2010, DEC placed the system into service and loaded data for DEC, DEO, and DERS into it, and DEC began to amortize the costs of the system over a 60-month period.

Witnesses Byrd and Williams testified that the tracking system was cumbersome because it required manual upload of data and manual reconciliation to the Company's general ledger. It was especially cumbersome in Ohio because it could not perform the weighted average cost calculations that were required by the Ohio statute. Consequently, DEO and DERS decided not to use the tracking system, but to instead manage their RECs through a payable system and an Excel spreadsheet. DEC considered making upgrades to the tracking system, but instead found a new program, Environmental Management Account (EMA), that performs all the functions of the DEC tracking system, plus some additional functions, in a more user-friendly manner and at a lower cost than upgrading the DEC tracking system. Consequently, DEC purchased a subscription to EMA, and in May 2012 it transferred its data to EMA. DEO and DERS removed their data from the DEC tracking system in September of 2011. Neither DEO nor DERS purchased an EMA subscription; instead, both chose to continue tracking their RECs on a spreadsheet.

Witness Williams testified that DEC wrote off the tracking system in May 2012, when it discontinued the use of the system. DEC and the Public Staff agree as to the amount of the costs that remain unrecovered, although that information was not part of the public testimony. Witness Williams proposed that all of these costs be recovered in calendar year 2012, the test year in this proceeding, and that they be collected through the EMF rider in this case. Her reason for making this proposal was that DEBS charged DEC for all of the remaining costs in 2012. Witness Williams further contended that all of the unrecovered costs of the system should be recovered from North Carolina ratepayers, and none from ratepayers in Ohio. She argued that the Ohio companies had never actually used the system, while DEC had. In addition, according to Public Staff witness Eastwood, DEC proposed to recover a $23,914 true-up that DEC made in 2012 to reflect 100 percent of the cost of the system being allocated to North Carolina from October 2011 through December 2011.

Public Staff witnesses Eastwood and Lucas testified that the tracking system was placed into service in March 2010, and asserted that in Docket No. E-7, Sub 936, the Commission approved an amortization period of 60 months, beginning in March 2010, for its costs. They testified that in the same docket, DEC had proposed and the Commission approved allocating only 81 percent of the system's costs to North Carolina customers. The Public Staff witnesses testified that the remaining costs of the system should not be charged entirely to North Carolina ratepayers.

The Public Staff witnesses further testified that DEC should amortize the remaining portion of the system's costs over the remaining term of the initial amortization period, which ends in February 2015. They argued that this would provide a more reasonable distribution of the costs than would be accomplished by charging the entire remaining cost to ratepayers in one year.

In summary, the Company proposed to recover all remaining unrecovered costs of the DEC tracking system from North Carolina customers via the REPS EMF rider that is pending in this docket and which will be in effect from September 1, 2013 through the end of August, 2014. The Public Staff asserted that DEC's Ohio affiliates should continue to be responsible for 19 percent of the costs, and recovery of North Carolina's share of the costs should extend until February of 2015.

The Commission agrees with the Public Staff that it is not reasonable for North Carolina customers to now pay 100 percent of the costs of a retired REC tracking system that was intended to be used by DEC and several other Duke Energy Corporation subsidiaries. From March 2010 on, the system was available to the Ohio entities for their use, whether or not they chose to use it. The fact that the Ohio entities withdrew their data from the system before DEC did does not provide any basis for transferring their share of the costs to North Carolina ratepayers. Given that the system will no longer be used by DEC or by any of DEC's affiliates, it is not reasonable to transfer the Ohio entities' share of its costs to DEC and its North Carolina customers.

The issue of cost recovery for DEC's internal REC tracking system was first addressed in the Commission's August 13, 2010 Order in Docket No. E-7, Sub 936. The test period for that case was the 12-month period ending December 31, 2009. The billing period was the 12-months ending August 31, 2011. DEC requested recovery of the costs of the system incurred in the test period. Rather than expense the entire cost of the system incurred in 2009 during the billing period ending August 31, 2011, DEC requested and the Commission authorized amortization of the expense item over a five-year period. The 2009 expense for the internal tracking system, but for the voluntary amortization, would have been recovered by August 31, 2011[1]. At issue in E-7, Sub 936 was only 81 percent of the total cost of the system. DEC intended for 19 percent to be recovered in Ohio.

The test period in this case is the 12-month period ending December 31, 2012. The billing period is the 12-month period ending August 31, 2014.

[1] NCUC Rule R8-67(e)(5) authorizes a REPS EMF. Use of this true-up ratemaking device would not have affected the recovery of the DEC internal REC tracking system costs.

The 19 percent of the cost of the internal tracking system DEC expensed in 2009 is not a test period expense in this case. To grant DEC's request to add the 19 percent DEC intended to recover in Ohio and failed to request in North Carolina in 2010 constitutes impermissible retroactive recovery of a pre-2012 incurred expense. DEC's failure to use the system in Ohio as intended when the expense was incurred came to light after the terms of recovery were finally established. It would be unfair to North Carolina ratepayers in 2013-2014 to make them responsible for 2009 test year costs based on facts that have transpired thereafter. If it were permissible to do so the Commission would be justified in disallowing costs of this expensive system that in retrospect has not provided the benefits for which it was intended.

Further, the Commission agrees with the Public Staff that DEC should continue to amortize the system's costs over the remaining term of the original amortization period, which ends in February 2015.

The Commission notes that both DEC and the Public Staff referenced the Commission's Order in Docket No. E-7, Sub 936 and asserted that the Commission there approved the five-year amortization of the costs in question. In that proceeding, the amounts in question were included within a broad cost category, "other incremental costs," and were only generally discussed in the Commission's August 13, 2010 Order Approving REPS and REPS EMF Riders. To improve the transparency of DEC's REPS rider requests the Commission will require the Company to provide a detailed worksheet in all future REPS rider applications explaining the discrete costs that it includes as "other incremental costs."

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 10-11

The evidence supporting these findings of fact is found in the testimony and exhibits of DEC witnesses Byrd and Williams and Public Staff witness Eastwood.

DEC witness Byrd testified that the Company is well positioned to provide a diverse and balanced portfolio of renewable resources that will qualify for the general REPS requirement during the billing period, together with a diverse and balanced portfolio of solar resources, although it is not well positioned to meet the requirements of the swine and poultry waste set-asides. In his Exhibit No. 2, witness Byrd listed the suppliers from which DEC expects to purchase renewable energy or RECs during the billing period, together with the amounts DEC expects to pay to these suppliers.

G.S. 62-133.8(h)(1) provides that "incremental costs" means "all reasonable and prudent costs incurred by an electric power supplier" to comply with the REPS requirements "that are in excess of the electric power supplier's avoided costs other than those costs recovered pursuant to G.S. 62-133.9." Witness Williams testified as to the calculation of DEC's avoided costs and its incremental costs of compliance with the REPS requirements, based on the incurred and projected costs provided by witness Byrd. She stated that for purchased power agreements with a renewable energy facility, DEC subtracted its avoided cost from the total cost associated with the renewable energy purchase to arrive at the incremental cost for that renewable energy purchase during the period in question. Consistent with Commission Rule R8-67(e)(2), which provides that the cost of an unbundled REC "is an incremental cost and has no avoided cost component," the total costs incurred during the test period for unbundled REC purchases were included in incremental costs, as were the projected costs for unbundled REC purchases during the billing period as discussed by witness Byrd.

Witness Williams stated that the EMF component of the proposed REPS rider included expenditures relating to co-firing that are recoverable under G.S. 62-133.8(h)(1)b. She indicated that the fuel and fuel-related costs of these operations were included in the Company's fuel filing pursuant to Rule R8-55 and G.S. 62-133.2.

Witness Williams further testified that the revenue requirements for DEC's solar photovoltaic distributed generation (solar PVDG) program are levelized and then reduced by avoided costs to determine incremental costs. During the fourth quarter of 2012, the Company received federal Section 1603 Grants (cash grants) in the amount of $11.5 million related to its solar PVDG program; the Company elected to receive these cash grants for this project in lieu of investment tax credits. The Company updated its levelized project cost calculation to remove the effects of normalized investment tax credits (applicable to regulated utilities) and to incorporate the reduction in the total project cost basis for the cash grants. Customers receive the benefit of the overall reduction in total project cost resulting from receipt of the cash grants through base rates, since the reduced total levelized cost remains above the project cost cap allowed to be recovered through the REPS rider.

According to witness Williams, in all cases where DEC determined incremental compliance costs as the excess amount above avoided cost, the Company applied an avoided cost rate in cents per kilowatt-hour (kWh) to the expected kWh of renewable energy for each compliance initiative. DEC's approved avoided cost rates are set forth in its Purchased Power Non-Hydroelectric, Schedule PP-N and Purchased Power Hydroelectric, Schedule PP-H rate schedules (collectively Schedule PP). For executed purchased power agreements, where the price of the REC and energy are bundled, the Company used annualized combined capacity and energy rates as shown on its Exhibit No. 3, filed in Docket No. E-100, Sub 106; Exhibit No. 3 in Docket No. E-100, Sub 117; or Exhibit No. 3 in Docket No. E-100, Sub 127, depending on the effective date of the executed contract. For those purchased power agreements with terms that did not correspond with the durational terms for which rates were established in the applicable avoided cost proceeding (i.e., two-, five-, ten- or fifteen-year durations), DEC computed avoided cost rates for the particular term of the purchased power agreements using the same inputs and methodology used for the applicable Schedule PP rates. The avoided cost components of energy and REC purchased power agreements effective during the billing period were calculated in the same manner.

Witness Williams testified that for the solar PVDG program, the Company determined the avoided cost using a process similar to that described above for a purchased power agreement with a non-standard duration. The inputs and methodology used for the Schedule PP rates approved in Docket No. E-100, Sub 117 were used to determine the annualized combined capacity and energy rates for a 20-year term, corresponding to the expected life of the solar facilities.

Witness Williams further presented testimony on DEC's allocation of REPS costs between its retail and wholesale customers, and its allocation of EE savings among its retail customer classes for purposes of determining REPS charges. She noted that DEC continues to provide services to native load priority wholesale customers that contract with the Company for

REPS compliance services, including delivery of renewable energy resources, compliance planning, and reporting. These customers (collectively referred to as wholesale customers) are Blue Ridge EMC, Rutherford EMC, the City of Concord, the Town of Dallas, the Town of Forest City, the Town of Highlands, and the City of Kings Mountain. The incremental cost of REPS compliance represents the cost to meet the combined total MWh requirement for native load customers, based on the sum of DEC North Carolina retail sales and Wholesale North Carolina retail sales. In order to properly allocate incremental costs between DEC and its wholesale customers, the Company used a combined aggregate cost cap as shown in Williams Exhibits No. 2 and No. 3 for the EMF period and billing period, respectively. The class allocation method combines the number of accounts subject to a REPS charge by customer class for both the DEC North Carolina retail accounts and the wholesale North Carolina retail accounts. In cases where a wholesale customer has chosen to self-supply a portion of its annual REPS requirement – for example, by using its Southeastern Power Administration allocation to partially meet the requirement as provided in G.S. 62-133.8(c) – or where the Company meets its compliance requirements by reduced energy consumption through implementation of EE measures, the combined total number of accounts on which the cost allocation is based has been adjusted on a pro-rata basis to recognize that a portion of the compliance will not be supplied by RECs generated or acquired by DEC as part of the combined total requirements. The adjusted totals by class were multiplied by the per account cost caps to determine the combined total cost cap dollar amounts by customer class and in total. Each customer class was then allocated its share of the incremental costs based on its pro-rata share of the customer cost cap dollar amounts. The cost allocated to each customer class was then divided by the total adjusted number of accounts within each customer class to arrive at an annual per-account charge. The annual per-account charge for each customer class was multiplied by the Company's North Carolina retail adjusted number of accounts within each customer class and totaled to arrive at the incremental cost to be allocated to DEC's North Carolina retail customers.

In allocating EE savings among the customer classes, incremental costs assigned to DEC North Carolina retail customers were separated into two categories: (a) costs related to the solar, poultry and swine compliance requirements or to research and other incremental costs (set-aside and other incremental costs), and (b) costs related to the general requirement[1] (general incremental costs). This separation is based on the percentage of set-aside and other incremental costs versus general incremental costs calculated on Williams Exhibit No. 1.

Set-aside and other incremental costs were allocated among customer classes based on per-account cost caps. General incremental costs were allocated among customer classes in a manner that gives credit for EE certificates (for which there are no general incremental costs) according to the relative energy reduction contributed by each customer class. As a result, general incremental costs were allocated among customer classes based on each class's pro-rata share of requirements for non-EE general RECs. In the future, should this method result in an allocation of costs to a particular class in excess of the cap limit for that class, the excess over the respective cap for that class will be re-allocated proportionally to the remaining classes.

Using this method, witness Williams calculated that DEC's incremental REPS compliance costs for the calendar year 2012, the test period in this case, amounted to

[1] The overall REPS requirement, net of the three set-asides, is generally referred to as the "general requirement."

$10,880,518, as shown on page 1, line 8 of Williams Exhibit No. 1. Public Staff witness Eastwood did not take issue with any aspect of witness Williams' calculation other than her proposed treatment of the write-off costs of DEC's internal REC tracking system. In Finding of Fact No. 9 above the Commission agrees with the Public Staff that North Carolina ratepayers should be allocated only 81 percent of the costs of DEC's internal REC tracking system, rather than 100 percent as witness Williams proposed. The Commission also agrees with the Public Staff that the costs should be amortized over a 38-month period ending in February 2015, rather than entirely in the test period as witness Williams proposed.

Witness Byrd testified that the Company sold some out-of-state RECs during the test period and flowed back the net proceeds through the REPS rider to the benefit of its customers. Witness Byrd stated that these transactions extended the useful life of the RECs held by the Company and reduced the customers' compliance burden by more than $1.25 million, as these proceeds will be refunded to customers through the REPS rider. The Public Staff did not take issue with these assertions. Public Staff witness Eastwood testified that she believed DEC appropriately flowed back the net proceeds to its customers in accordance with the Public Staff's position in its initial and reply comments pertaining to the accounting treatment of gains on REC sales.[1]

Witness Eastwood's exhibits reflected her method of correcting witness Williams' treatment of the tracking system write-off. She began with witness Williams' proposed write-off and reduced it by $23,914, an amount that witness Williams had added so that no portion of the costs of the system would be charged to Ohio ratepayers after DEO and DERS stopped using the system in September 2011. Witness Eastwood allocated 81 percent of the remaining amount to North Carolina ratepayers. She divided this amount by 38 to determine the write-off for each month, and she included 12 of these monthly write-offs, or $407,777, in test-year REPS compliance costs. On this basis she determined that DEC's "other incremental costs" for the test year (i.e., other than REC purchase costs, research costs, and the incremental costs of bundled renewable energy) were $1,853,670, and the Company's total test-period REPS incremental costs amounted to $9,670,191. Neither the Public Staff nor any other intervenor contended that any of these costs were incurred imprudently.

Witness Eastwood proceeded to allocate the test-period REPS incremental costs between DEC's retail and wholesale customers, and among the classes of its North Carolina retail customers. She compared the incremental costs for each of the three retail customer classes with the actual REPS revenues received during the test period from the three classes, and she found that DEC's over-collections for the test period were $3,800,313 for the residential class, $180,867 for the general service class, and $395,165 for the industrial class, excluding interest, gross receipts tax, and the regulatory fee.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12-15

The evidence for these findings of fact appears in DEC's application and in the testimony and exhibits of Public Staff witness Eastwood.

[1] The Commission's inquiry into this issue in Docket No. E-100, Sub 113, is pending.

Witness Eastwood's Exhibit No. 1, Schedule 5, showed that she calculated a test-period over-collection of REPS costs amounting to $3,800,313 for the residential class, $180,867 for the general service class, and $395,165 for the industrial class, excluding interest, gross receipts tax, and the regulatory fee. With interest included, but still excluding gross receipts tax and the regulatory fee, the over-collections are $4,433,698 for the residential class, $211,011 for the general service class, and $461,026 for the industrial class. As reflected on her Exhibit No. 1, Schedule 9, witness Eastwood calculated monthly REPS EMF charges of ($0.23), ($0.08) and ($7.71) per customer account for residential, general service, and industrial customers, respectively, excluding gross receipts tax and the regulatory fee.

Witness Eastwood calculated projected REPS costs for the billing period in the amount of $3,750,115 for the residential class, $8,695,138 for the general service class, and $1,102,011 for the industrial class, excluding gross receipts tax and the regulatory fee. Her proposed monthly REPS riders, as shown on her Schedule 9, and again excluding gross receipts tax and the regulatory fee, were $0.19, $3.22, and $18.44 per customer account for residential, general service and industrial customers, respectively.

Eastwood Exhibit No. 2 indicated that the combined monthly amounts of the REPS and REPS EMF riders, excluding gross receipts tax and the regulatory fee, per customer account, to be billed during the 2013-14 billing period, are ($0.04) for residential accounts, $3.14 for general service accounts, and $10.73 for industrial accounts. As shown in Eastwood Exhibit No. 1, Schedule 9, the annual charges for each customer class are well below the caps established in G.S. 62-133.8.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

The evidence supporting this finding of fact is found in the testimony and Exhibit No. 1 of Public Staff witness Lucas, as well as the REPS report submitted as Exhibit No. 1 by DEC witness Byrd.

Witness Lucas testified that, in response to a data request, DEC had provided the Public Staff with a spreadsheet showing how the Company tracks its EECs. Witness Lucas submitted the spreadsheet as Exhibit No. 1 to his testimony. He explained that DEC "removes any EECs that are later proved to be invalid by EM&V [evaluation, measurement and verification]." He stated that "NC-RETS also has a process that allows the electric power suppliers to account for retired EECs that later prove to be invalid."

Lucas Exhibit No. 1 showed that DEC proposed to use 419,745 EECs toward its 2012 REPS obligation. This is consistent with the Company's REPS compliance report, which was submitted as Byrd Exhibit No. 1.

Witness Lucas recommended that the Commission approve DEC's tracking method for this proceeding. Since no party opposed the Public Staff's proposal, the Commission will adopt it. However, in order to provide more transparency and to help prevent invalid EECs from being used for REPS compliance, the Commission will require DEC to file its spreadsheet for tracking EECs, along with supporting testimony, in future REPS proceedings. In addition, because it is possible that an electric power supplier might initially over-state its EE accomplishments and thereby create too many EECs in NC-RETS, pending EM&V, the Commission agrees with the Public Staff that DEC should maintain a sufficient number of banked EECs to preclude its balance from becoming negative if subsequent EM&V reveals less EE had actually occurred.

IT IS, THEREFORE, ORDERED as follows:

1. That DEC shall establish a REPS rider as described herein, in the amounts approved herein, and that this rider shall remain in effect for a 12-month period beginning September 1, 2013, and expiring August 31, 2014;

2. That DEC shall establish a REPS EMF rider as described herein, and that this rider shall remain in effect for a 12-month period beginning September 1, 2013, and expiring August 31, 2014;

3. That DEC shall file appropriate rate schedules and riders with the Commission in order to implement the provisions of this Order as soon as practicable, but not later than ten days after the date of this Order;

4. That DEC shall work with the Public Staff to prepare a joint notice to customers of the rate changes ordered by the Commission in this docket, as well as in Docket No. E-7, Sub 1033, and the Company shall file such notice for Commission approval as soon as practicable, but not later than ten days after the date of this Order;

5. That DEC's 2012 REPS compliance report is hereby approved and the RECs and EECs in DEC's 2012 compliance sub-accounts in NC-RETS shall be retired;

6. That DEC shall, in all future REPS rider applications, provide a detailed worksheet explaining each discrete item contributing to "other incremental costs," as well as a worksheet and supporting testimony detailing its EEC inventories and linking them to its EM&V reports; and

7. That DEC shall file in all future REPS rider applications the results of studies the costs of which were recovered via its REPS EMF and rider, including the overall program number and specific project number for each project sponsored by EPRI; and, for those studies that are subject to confidentiality agreements, information (including an internet or mailing address) regarding how parties can access the results of those studies.

ISSUED BY ORDER OF THE COMMISSION.
This the 20th day of August, 2013.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

kj082013.01

Former Commissioners William T. Culpepper, III, and Lucy T. Allen, and present Commissioners Susan W. Rabon, Don M. Bailey, James G. Patterson and Jerry C. Dockham did not participate in this decision.

DOCKET NO. E-2, SUB 1023

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Carolina Power & Light	)	
Company, d/b/a Progress Energy Carolinas,	)	ORDER GRANTING
Inc., for Adjustment of Rates and Charges	)	GENERAL RATE INCREASE
Applicable to Electric Utility Service in	)	
North Carolina	)	

HEARD: Tuesday, February 19, 2013, at 7:00 p.m., in the New Hanover County Courthouse, Courtroom 403, 316 Princess Street, Wilmington, North Carolina

Wednesday, February 20, 2013, at 7:00 p.m., in the Richmond County Courthouse, 105 West Franklin Street, Rockingham, North Carolina

Tuesday, February 26, 2013, at 7:00 p.m., in the Greene County Courthouse, 301 North Greene Street, Snow Hill, North Carolina

Tuesday, March 5, 2013, at 7:00 p.m., in the Buncombe County Courthouse, District Courtroom #1 (basement), 60 Court Plaza, Asheville, North Carolina

Wednesday, March 13, 2013, at 7:00 p.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

Monday, March 18, 2013, at 1:00 p.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman Edward S. Finley, Jr., Presiding; Commissioners William T. Culpepper, III; Bryan E. Beatty; Susan W. Rabon; ToNola D. Brown-Bland, and Lucy T. Allen

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BY THE COMMISSION: On September 5, 2012, pursuant to Commission Rule R1-17(a), Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc., which subsequently changed its name to Duke Energy Progress, Inc. (DEP or the Company), filed notice of its intent to file a general rate case application. On October 12, 2012, 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), and the direct testimony and exhibits of Lloyd Yates, Executive Vice President, Customer Operations, Duke Energy Corporation (Duke Energy);[1] Laura A. Bateman, Manager, Rates and Regulatory Strategy, Progress Energy Service Company, Inc.; J. Danny Wiles, Director of Regulated Accounting, Duke Energy; William R. Hopkins, Executive Advisor, Concentric Energy Advisors; Bruce P. Barkley, Manager-Regulatory Affairs, Duke Energy; Robert B. Hevert, Managing Partner, Sussex Economic Advisers, LLC; and Michael T. O'Sheasy, Vice President, Christensen Associates, Inc.

Petitions to intervene were filed by CIGFUR II and NC WARN on September 10, 2012, CUCA on October 4, 2012, the Commercial Group on October 26, 2012, NCEMPA on November 7, 2012, NCSEA on November 9, 2012, Kroger on December 5, 2012, Fayetteville

[1] Duke Energy Progress is a wholly owned subsidiary of Progress Energy, Inc., which in turn is a wholly owned subsidiary of Duke Energy. (T, Vol. 2, p. 15)

PWC on December 6, 2012, Time Warner on February 7, 2013, UMS and LCFWSA on February 8, 2013, the DoD on February 8, 2013, and NCLM on February 11, 2013. Notice of intervention was filed by the Attorney General on November 16, 2012.

The Commission entered orders granting the petitions of CIGFUR II and NC WARN on September 13, 2012, CUCA on October 8, 2012, the Commercial Group on October 31, 2012, NCEMPA on November 9, 2012, NCSEA on November 15, 2012, Kroger on December 6, 2012, Fayetteville PWC on December 7, 2012, Time Warner on February 13, 2013, NCLM on February 13, 2013, UMS and LCFWSA on February 18, 2013, and the DoD on February 18, 2013. The Public Staff's intervention is recognized pursuant to N.C. G.S. 62-15(d) and Commission Rule R1-19. The Attorney General's intervention is recognized pursuant to G.S. 62-20.

On November 5, 2012, the Commission issued its Order Scheduling Investigation and Hearing, Suspending Proposed Rates, Establishing Intervention and Testimony Due Dates and Discovery Guidelines, and Requiring Public Notice.

The Company filed the supplemental testimony and exhibits of Company witnesses Bateman and O'Sheasy on January 18, 2013.

Pursuant to the Commission's November 5, 2012, Scheduling Order, the testimony and exhibits of the Public Staff and other intervenors were to be filed on or before February 18, 2013. The Commission, however, issued orders granting extensions of time on February 15, 2013, February 19, 2013, and February 21, 2013, which extended the date for the Public Staff and other intervenors to file their testimony and exhibits to February 20, 2013, February 22, 2013, and February 25, 2013, respectively.

On February 18, 2013, Time Warner filed the direct testimony and exhibits of Brian W. Coughlan, President, founder, and owner of UMS and the DoD filed the direct testimony and exhibit of Thomas J. Prisco, Accountant in the Regulatory Law and Intellectual Property Division, Office of The Judge Advocate General, Department of the Army. On February 20, 2013, Kroger filed the direct testimony and exhibits of Kevin C. Higgins, Principal in the firm Energy Strategies, LLC; UMS and LCFWSA filed the direct testimony of Brian W. Coughlan; and NC WARN filed the direct testimony and exhibits of William B. Marcus, Principal Economist, JBS Energy, Inc. On February 22, 2013, NCLM filed the direct testimony of Daniel A. Howe, Assistant City Manager for the City of Raleigh, and Bill Saffo, Mayor of the City of Wilmington. On February 25, 2013, CIGFUR II filed the direct testimony and exhibits of Nicholas Phillips, Jr., consultant in the field of public utility regulation and a Managing Principal of Brubaker & Associates, Inc., energy, economic and regulatory consultants.

On February 25, 2013, the Public Staff filed a Notice of Settlement in Principle with DEP. The Commission also granted a further extension of time for filing the testimony and exhibits of the Public Staff and other intervenors to February 28, 2013.

On February 28, 2013, DEP and the Public Staff entered into and filed an Agreement and Stipulation of Settlement. The Agreement and Stipulation of Settlement resolves all issues between the two parties in this docket, with the exception of: (1) the Company's proposal for an

Industrial Economic Recovery rider (Rider IER); (2) the appropriate methodology for cost allocation between jurisdictions and customer classes; and (3) the deferral of costs associated with the Company's new combined cycle plant in Richmond County, North Carolina (Richmond CC).[1]

In support of the Stipulation, on February 28, 2013, the Public Staff filed the direct testimony and exhibits of Ben Johnson, Consulting Economist and President, Ben Johnson Associates, Inc.; John R. Hinton, Director of the Economic Research Division of the Public Staff; James G. Hoard, Director of the Accounting Division of the Public Staff; Kennie D. Ellis, Engineer in the Electric Division of the Public Staff; Jack L. Floyd, Engineer in the Electric Division of the Public Staff; James D. McLawhorn, Director of Electric Division of the Public Staff; and Michael C. Maness, Assistant Director of the Accounting Division of the Public Staff.

On February 28, 2013, CUCA filed the direct testimony and exhibits of Kevin O'Donnell, President of Nova Energy 3 Consultants, Inc., and the Commercial Group filed the direct testimony and exhibits of Steve Chriss, Senior Manager, Energy Regulatory Analysis, for Wal-Mart Stores, Inc., and Wayne Rosa, Energy and Maintenance Manager for Food Lion, LLC.

On March 6, 2013, DEP and the Public Staff filed a corrected version of page 4 of the Agreement and Stipulation of Settlement, which corrects several misstated sales revenue numbers in the chart in Paragraph 2.B. and corrects Floyd Exhibits 1 and 2. On March 14, 2013, DEP and the Public Staff filed an Amendment to the Agreement and Stipulation of Settlement withdrawing the Company's request to include its Distribution System Demand Response program (DSDR) in base rates, and a Revised Settlement Exhibit 1.

On March 14, 2013, DEP filed the rebuttal testimony and exhibits of witnesses Paul R. Newton, State President – North Carolina, Progress Energy Carolinas; Stephen G. De May, Vice President and Treasurer, Duke Energy Business Services LLC;[2] Garry D. Miller, Senior Vice President of Nuclear Engineering, Duke Energy; Julius A. Wright, Managing Partner, J.A. Wright & Associates, LLC; Laura A. Bateman; Robert B. Hevert; William R. Hopkins; and Michael T. O'Sheasy.

On March 15, 2013, the Public Staff filed Revised Exhibit 1 of James G. Hoard and the revised testimony and exhibit of Michael C. Maness to reflect the effect of the withdrawal of the Company's request to include DSDR in base rates.

On March 18, 2013, the Public Staff filed Revised Exhibits 1 and 2 to Jack L. Floyd's direct testimony. The Public Staff filed a supplement to Revised Floyd Exhibit 1 on March 20, 2013.

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[1] On March 22, 2013, the Commission denied the Company's deferral request for the Richmond CC in Docket No. E-2, Sub 1026. Therefore, the third point of disagreement between DEP and the Public Staff has been resolved.

[2] Duke Energy Business Services LLC provides various administrative and other services to DEP and other affiliated companies of Duke Energy.

On March 19, 2013, DEP and the Public Staff filed a Second Amendment to the Agreement and Stipulation of Settlement, agreeing to strike the phrase "Riders 7, 66, and SSSW" in Paragraph 5.B.(5) and replace it with "Riders 66 and SSSW".[1]

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

Wilmington: John Elliot, Robin Spinx, Henry Kitchen, Scott Sullivan, Bianca Oyaneder, Jesse Hannible, Sonya Bennetone, Mario Pinierio, Matt Collogan, Emma Bogdan, Kate Held, Alina Szmant, Clifton Cash, Paul Pascarosa, John Agagnost, John Gray, Emilia Wicker, Carol Swift, and Adam Sopak

Rockingham: Joseph Kearns, Antonio Blue, Dale McInnis, Nancy Mebane Shakir, and Charleen Morrow

Snow Hill: Troy Smith, Dorothy Allsbrook, David Jones, Albert Barron, Sr., Theodore Woolridge, Joanna Helms, Denny Garner, James Grimes, Prentice Lanier, Zebedee Sheppard, Antonio Blow, Charles Wright, Ricky Petteway, Melanie Goff Bradley, Margaret Sowerwine, Willie Battle, Tony Tyson, James Edwards, Jake Gellar-Goad, Kimberly Carney, Ben Lanier, and Gerrick Brenner

Asheville: Paul Szurek, Mac Swicegood, Bob Cozart, Kelly Martin, Stephanie Biziewski, Lewis Patrie, Tamara Puffer, Melissa Williams, Anna Jane Joyner, Emily Greenbaum, Grant Mincy, Andrew Weatherly, Reid Rhodes, Kimberly Rhodes, Maureen Linneman, Debby Genz, Anne Craig, Amy Ende, Abbey Ende, Clare Ende, Bob Gale, Richard Genz, Cathy Scott, Teddy Jordan, Valerie Hoh, Edward Dale, Charles Jansen, Dan Clere, Kendall Hale, Steve Norris, Julia Rankin, Cathy Holt, Bill Maloney, Curry First, Cam Murchison, Steve Runholt, Robert Howarth, Greg Borom, Dan Rattigan, James Lee, Judy Mattox, Rachael Bliss, Sophia Brooks, Bridget Herring, Sherry Ingram, Rachel Larson, Noah Wilson, Jim Barton, Avram Friedman, Richard Fireman, Tom Coulson, Terrence Clark, Loren Hart, Beth Henry, Sierra Hollister, and Erica Schneider

Raleigh: Karen Mallam, Gina Dean, Lee Ann Nance, Amy Thai, Harvey Richmond, Jaclyn Mills, Sarah Gaskill, Margaret Peeples, Clara Exum, Bob Robinson, Wanda Webb Schrader, Margaret Toman, Elizabeth Hutchby, Tanya Godsey, Lee Howe, Rachel Wooten, Jerome Levisy, Octavia Rainey, Jason Welsch, Robert Black,

[1] Hereinafter, the Agreement and Stipulation of Settlement, as corrected on March 6, 2013, and as amended on March 14, 2013, and March 19, 2013, shall be referred to as the Stipulation and the Stipulating Parties shall mean DEP and the Public Staff.

Madhura Deshpande, Nicole Assef, Kristen Norris, Jonathan Sumner, and Audrey Schwankl

The matter came on for evidentiary hearing on March 18, 2013. The Company presented the testimony of witnesses Yates, Newton, Hevert, De May, Bateman, Hopkins, Wright and O'Sheasy. The Public Staff presented the testimony of witnesses Hoard, Johnson, McLawhorn, and Floyd. The parties waived cross-examination of Public Staff witnesses Hinton, Maness, and Ellis; their testimony and exhibits were entered into the record without objection. CUCA presented the testimony of witness O'Donnell. Kroger presented the testimony of witness Higgins. Witness Coughlan testified on behalf of Time Warner, UMS and LCFWSA. The DoD presented the testimony of witness Prisco. NCLM presented the testimony of witnesses Saffo and Howe. The Commercial Group presented the testimony of witnesses Chriss and Rosa. NC WARN presented the testimony of witness Marcus. The pre-filed testimony of those witnesses who testified at the evidentiary hearing, as well as all other witnesses filing testimony in this docket, was copied into the record as if given orally from the stand.

On April 1, 2013, the Commission issued a notice of mailing of transcript and ordered that the parties submit briefs and/or proposed orders not later than April 24, 2013. This deadline was subsequently extended to April 29, 2013.

On April 29, 2013, DEP, the Public Staff and several other parties filed briefs and/or proposed orders.

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 AND CONCLUSIONS

Jurisdiction

1. Duke Energy Progress is duly organized as a public utility operating under the laws of the State of North Carolina and is subject to the jurisdiction of this Commission. The Company is engaged in the business of generating, transmitting, distributing, and selling electric power to the public in a broad area in eastern North Carolina and an area in western North Carolina in and around the city of Asheville. DEP is a wholly-owned subsidiary of Duke Energy, and its office and principal place of business are located in Raleigh, North Carolina.

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

3. Duke Energy Progress is lawfully before the Commission based upon its Application for a general increase in its retail rates pursuant to G.S. 62-133 and 62-134 and Commission Rule R1-17.

4. The appropriate test period for use in this proceeding is the 12 months ended March 31, 2012, adjusted for certain known changes in revenue, expenses, and rate base through January 31, 2013.

The Application

5. Duke Energy Progress, by its Application and initial direct testimony and exhibits, originally sought a net increase of approximately $359 million, or 11%, in its annual electric sales revenues from its North Carolina retail electric operations, including a rate of return on common equity (ROE) of 11.25%. The Company requested a non-fuel base rate increase of approximately $387 million. When considered in conjunction with the proposed reduction to the Company's demand side management/energy efficiency (DSM/EE) rider to remove approximately $28 million of costs associated with the Company's DSDR program, the net total rate increase requested was approximately $359 million.

6. Duke Energy Progress submitted evidence in this case with respect to revenue, expenses, and rate base using a test period consisting of the 12 months ended March 31, 2012, adjusted for certain known changes in revenue, expenses, and rate base.

The Stipulation

7. On February 25, 2013, the Public Staff filed a Notice of Settlement in Principle with DEP. On February 28, 2013, DEP and the Public Staff entered into and filed an Agreement and Stipulation of Settlement, a corrected version of which was filed on March 6, 2013, resolving most of the issues in this proceeding between the Public Staff and DEP (Stipulating Parties). On March 14, 2013, DEP and the Public Staff filed an Amendment to the Stipulation withdrawing the Company's request to include DSDR in base rates. On March 19, 2013, the Stipulating Parties filed a Second Amendment to the Stipulation agreeing to strike the reference to Rider 7 in Paragraph 5.B.(5). As amended, the Stipulating Parties' agreement is referred to herein as the Stipulation.

8. The Commission, having carefully reviewed the Stipulation finds and concludes that the Stipulation is the product of the give-and-take of settlement negotiations between the Stipulating Parties, is material evidence in this proceeding and is entitled to be given appropriate weight in this proceeding.

9. The Stipulation provides for a two year step-in increase in the Company's annual electric sales revenues from its North Carolina retail electric operations, effective June 1, 2013. This step-in of the rate increase will occur through a delay in the Company's collection of the financing costs on the construction work in progress (CWIP) for its new combined cycle Sutton natural gas plant (Sutton CC) for one year. In year one, the Stipulation provides for an increase in rates of $147,384,000. In year two, the Stipulation provides for an additional increase in rates of $31,328,000, for a total increase of $178,712,000.[1]

[1] This increase is exclusive of the coal inventory rider, which is separately addressed in Finding of Fact and Conclusion No. 34.

10. The Stipulation provides that the following amounts of test year pro forma operating revenues, operating revenue deductions, and original cost rate base (under present rates) are to be used as the basis for setting rates in this proceeding: $3,224,444,000 of operating revenues, $2,822,979,000 of operating revenue deductions, and $6,701,450,000 of original cost rate base.

11. The Stipulating Parties agree that the revenue increase of $178,712,000 is intended to provide DEP, through sound management, the opportunity to earn an overall rate of return of 7.55%. This overall rate of return is derived from applying DEP’s long-term debt cost of 4.57% and a return on equity (ROE) of 10.20% to a capital structure consisting of 47% long-term debt and 53% common equity. The Commission finds and concludes that the Stipulation is material evidence entitled to appropriate weight in determining DEP’s overall rate of return, cost of debt, ROE, and capital structure.

12. Based on the expert witness evidence, the public witness evidence and the Stipulation, the Commission finds 10.2% to be a reasonable return on common equity for DEP in this general rate case.

13. Based on the expert witness evidence, the public witness evidence and the Stipulation, the Commission finds a capital structure of 53% equity and 47% debt to be a reasonable capital structure for DEP in this general rate case.

14. The Company's actual embedded long-term debt cost is 4.57%.

15. The increased capital and operating costs that DEP seeks to recover by increasing its rates were prudently and reasonably incurred by DEP, and were necessary in order for DEP to meet its obligation to provide safe, adequate and reliable electric service. There is no credible or substantial evidence disputing the prudency, reasonableness or necessity of these costs.

16. Changing economic conditions in North Carolina during the last several years have caused high levels of unemployment, home foreclosures and other economic stress on DEP's customers.

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

18. Continuous safe, adequate and reliable electric service by DEP is essential to the support of businesses, jobs, hospitals, government services, and the maintenance of a healthy environment.

19. The ROE and capital structure approved by the Commission appropriately balances the benefits received by DEP's customers from DEP's provision of safe, adequate and reliable electric service in support of businesses, jobs, hospitals, government services, and the maintenance of a healthy environment with the difficulties that some of DEP's customers will experience in paying DEP's increased rates.

20. The 10.2% ROE and the 53% equity financing approved by the Commission in this case are as low as reasonably possible. They appropriately balance DEP's need to obtain equity financing and maintain a strong credit rating with its customers' need to pay the lowest possible rates.

21. The difficulties that DEP's low-income customers will experience in paying DEP's increased rates will be mitigated to some extent by the $20 million that DEP will contribute to assistance for low-income customers and job training.

22. The Commission has reviewed the Stipulation's provisions for a two-step annual electric sales revenue increase totaling $178,712,000 ($147,384,000 in the first step and $31,328,000 in the second step) and finds and concludes that this increase in the level of base rates to be paid by DEP's North Carolina retail customers is just and reasonable to all parties in light of all the evidence presented.

23. The Stipulation provides that DEP shall implement a decrement rider for one year, beginning on the effective date of the rates approved in this proceeding, to delay inclusion of Sutton CWIP in rate base, resulting in a $31,328,000 reduction in the revenue increase. The Company will continue to accrue allowance for funds used during construction (AFUDC) on the Sutton CC from the effective date of the rate until the plant is placed in service. The Commission finds and concludes that the Stipulating Parties' agreement with respect to the delay of the Sutton CWIP as set forth in Paragraph 8.I. of the Stipulation is just and reasonable to all parties in light of all the evidence presented.

24. The North Carolina retail base fuel expense for this proceeding is $1,099,039,000, and the following base fuel and fuel-related cost factors are just and reasonable to all parties in light of all the evidence presented, for purposes of this proceeding (amounts are cents per kilowatt-hour (kWh), excluding gross receipts tax and regulatory fee): 3.030 for residential customers; 3.020 for SGS customers; 2.935 for MGS customers; 2.969 for LGS customers; and 3.692 for Lighting customers.

25. The Stipulation provides that beginning with the effective date of the rates, the North Carolina retail fuel line loss differential shall be recovered as part of the fuel and fuel-related cost factor, and not as part of the non-fuel component of base rates. The Company will include the line loss differential in the prospective component of its fuel and fuel-related cost factor in the Company's annual fuel charge proceedings, beginning with the proceeding filed in 2013, and true it up through the fuel EMF process.

26. G.S. 62-133.2 was amended by the General Assembly in S.L. 2007-297 (Senate Bill 3) to allow certain fuel-related costs that had previously been recovered only through base rates to be recovered as part of the annual fuel charge adjustment for the electric utilities. The Stipulating Parties agree that these costs for DEP will be allocated as part of its annual fuel charge adjustment, provided, however, that the Commission's decision to approve such allocations shall not be precedent for and may be contested in a future general rate case proceeding. The Commission finds and concludes that the allocation of fuel and fuel-related costs, as set forth in Paragraph 3.C. of the Stipulation, is just and reasonable to all parties in light of all the evidence presented.

27. The Stipulation provides for the implementation of the rate design proposed by witness O'Sheasy in his direct testimony, subject to certain modifications set out in detail in Paragraph 5 of the Stipulation. The Commission finds and concludes that the Stipulation is material evidence entitled to be given appropriate weight in determining DEP's rate design. Based on all the evidence presented in this proceeding, the Commission finds and concludes that the changes to the Company's rate design, as described in the Stipulation, are just and reasonable. Except to the extent modified in the Stipulation, the Commission finds and concludes that the rate design proposed by witness O'Sheasy is just and reasonable to all parties in light of all the evidence presented. The Company shall implement the rate design proposed by witness O'Sheasy, as well as the specific modifications set forth in Paragraph 5 of the Stipulation.

28. Based on all of the evidence and Paragraph 7 of the Stipulation, the Commission finds and concludes that the overall quality of electric service provided by DEP is good.

29. The Stipulation provides that the Company will convert $20 million of a regulatory liability for the benefit of the Company's North Carolina retail customers to be allocated among (a) local agencies and organizations for programs that provide assistance to low-income customers and (b) programs that provide training that improve worker access to jobs and increase the quality of the workforce. These funds will be contributed no later than January 1, 2014, and reflected on the Company's books by a corresponding reversal to income in the same amount from the cost of removal component of Account 108. The Company will consult with the Public Staff and submit a specific proposal for distribution of the funds within 60 days of this Order for Commission review and approval. 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.

30. As set forth in Settlement Exhibit 1, the Stipulation provides for a reduction in the amounts the Company collects for nuclear decommissioning. In accordance with Paragraph 8.B. of the Stipulation, the Public Staff shall not oppose the Company's deferral request for any changes in decommissioning cost and funding requirements based on future decommissioning studies filed with the Commission. 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.

31. As provided in Settlement Exhibit 2 and set forth in Paragraph 8.D. of the Stipulation, the Company may use levelization accounting for nuclear refueling costs, effective January 1, 2013. 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.

32. As set forth in Paragraph 8.E. of the Stipulation and based on all the evidence presented, the Commission finds and concludes that it is appropriate to include amortization of the deferred costs associated with DEP's Wayne County Combined Cycle natural gas-fired generating facility (Wayne CC) in the Company's test-period cost of service for purposes of this proceeding.

33. Paragraph 8.H. of the Stipulation provides that the revenue requirement includes an adjustment to cost of service to normalize storm restoration costs for the test period in this proceeding. The Stipulation also provides that the Public Staff may oppose any request by the

Company to defer or amortize future storm restoration costs on the grounds that the request is inconsistent with this normalization. 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.

34. Paragraph 8.G. of the Stipulation provides for a reduction in the amount of coal inventory included in working capital. The Stipulation also provides that the stipulated revenue increase is subject to an increment rider, effective June 1, 2013, and expiring at the earlier of (a) November 30, 2014, or (b) the Coal Inventory Rider Termination Date,[1] to allow the Company to recover the additional costs of carrying coal inventory in excess of a 40-day supply (priced at $91.623 per ton). The Stipulation further provides that the Company may request an extension of the November 30, 2014 date. The Commission finds and concludes that the increment rider, as set forth in the Stipulation, is just and reasonable to all parties in light of all the evidence presented.

35. The Commission finds and concludes based on all of the evidence that the provisions of the Stipulation are just and reasonable to all parties to this proceeding and serve the public interest. Therefore, the Stipulation should be approved in its entirety.

Cost of Service Allocation Method

36. The Commission finds and concludes that the summer coincident peak (1CP) method is the most appropriate method for allocating costs between jurisdictions and between customer classes within the North Carolina retail jurisdiction for DEP in this proceeding. The Commission, having considered all of the evidence presented, finds that the 1CP methodology is just and reasonable to all parties.

Industrial Economic Recovery Rider

37. The Company's proposed Industrial Economic Recovery Rider (Rider IER) is a 5-year experimental discount rider that would provide retail electric service at a reduced rate to the Company's industrial customers as determined by the United States Government's Standard Industrial Classification (SIC) Manual. The main purpose of the Rider is to preserve industrial jobs by avoiding further reductions in the number of DEP's industrial customers and the level of operations of DEP's industrial customers. In order to receive the reduced rate, the industrial customer would be required to state that it reasonably expects to maintain current employment levels and that it will request or receive an energy audit within 12 months of requesting service under Rider IER.

38. There is no substantial evidence that the reductions in the number of DEP's industrial customers and the level of operations of DEP's industrial customers were caused by

[1] The Stipulation provides that the Coal Inventory Rider Termination Date is the last day of the month in which the Company's actual coal inventory levels return to a 40-day supply on a sustained basis. For this purpose, three consecutive months of total coal inventory of 42 days or below will constitute a sustained basis. Any over- or under-collection of costs experienced as a result of this rider shall be trued up at the time of the proceeding held to set DEP's DSM/EE Program Rider, REPS Rider, and Fuel Adjustment Rider. Any interest on over- or under-collection shall be set to the Company's net-of-tax overall rate of return, as approved by the Commission in this proceeding.

DEP's industrial rates. In addition, there is no substantial evidence that a discount in DEP's industrial rates would be a material factor in avoiding future reductions in the number of DEP's industrial customers and the level of operations of DEP's industrial customers.

39. There is no substantial evidence that Rider IER would result in job retention by DEP’s industrial customers, which is the intended main benefit that other DEP ratepayers would receive in return for paying higher rates to support Rider IER. Therefore, the evidence fails to show that Rider IER will result in just and reasonable rates.

Distribution System Demand Response

40. DEP originally proposed to reduce its demand-side management/energy efficiency (DSM/EE) rider by $28 million and increase base rates by $32 million for costs associated with its distribution system demand response (DSDR) program. The Amended Stipulation between DEP and the Public Staff withdrew that proposal. While this issue requires no determination by the Commission at this time, the Commission will require DEP to file additional information about DSDR in its next DSM/EE rider proceeding and in its 2014 fuel proceeding.

EVIDENCE IN SUPPORT OF FINDINGS OF FACT AND CONCLUSIONS NOS. 1-4

The evidence supporting these findings and conclusions is contained in the verified Application and Form E-1 of DEP, 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.

EVIDENCE IN SUPPORT OF FINDINGS OF FACT AND CONCLUSIONS NOS. 5-8

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

On October 12, 2012, DEP filed its Application and initial direct testimony and exhibits, seeking a net increase of approximately $359 million, or 11%, in its annual electric sales revenues from its North Carolina retail electric operations. On February 28, 2013, the Company and the Public Staff entered into and filed an Agreement and Stipulation of Settlement, which was corrected on March 6, 2013, and amended on March 14, 2013, and March 19, 2013. The Stipulation resolves most of the issues in this proceeding between these two parties and provides for a net increase of $178,712,000 in DEP’s annual revenues from its North Carolina retail electric operations, to be phased in over two years. The Company submitted evidence in this case with respect to revenue, expenses, and rate base using a test period consisting of the 12 months ended March 31, 2012, updated for certain known and actual changes. The Stipulation is based upon the same test period.

Need for Rate Increase

Company witness Yates testified that the primary objective of the rate increase requested by the Company is to enable it to continue providing safe, reliable, cost-effective, and environmentally compliant electricity. Witness Yates explained the primary cost drivers making up the requested rate increase and described the steps the Company has taken to minimize its cost to provide electricity to its customers.

Witness Yates explained that electric service provided by DEP is still a good value for customers, who have paid the same base rate for electricity since the Company's last general rate case in 1988 in Docket No. E-2, Sub 537. For much of the last 25 years, new capital additions and increased operating costs have been offset by additional revenues from customer growth and savings from operating efficiencies to allow the Company to avoid requesting a base rate increase. However, new customer growth and sales have decreased significantly since the 2008 financial crisis, resulting in less load over which to spread the costs. Prior to 2008, the Company was adding, on average, 24,000 new residential customers per year. In 2009 and 2010, these numbers fell to 8,700 and 7,200, respectively. For most classes, usage per customer decreased in the test period. Also, the demands placed on the Company and its power system by increasing environmental regulation and aging infrastructure has required the Company to make significant capital investments. The Company's fleet modernization effort is the primary driver of this rate case. Additionally, increased expenses related to nuclear operations and vegetation management are contributing significantly to the need to file this case.

According to witness Yates, over the last 25 years, DEP has made significant investments to modernize its generation fleet by replacing older, less efficient coal-fired generation with state-of-the-art, cleaner-burning natural gas-fueled plants, such as the new natural gas combined cycle plants located in Richmond and Wayne Counties and the Sutton CC plant located in New Hanover County. The 600-megawatt (MW) Richmond CC was placed into service in June 2011, the 950-MW Wayne CC was placed into service in December 2012, and the Company expects to place the 620-MW Sutton CC into service in December 2013. Over the last decade, in order to comply with the North Carolina Clean Smokestacks Act, DEP has also been retiring or retrofitting its larger, older coal-fired plants. The Company has installed state-of-the-art sulfur dioxide (SO_2) emissions-reduction equipment (scrubbers) and selective catalytic reduction (SCR) systems on its seven units at the Asheville, Mayo, and Roxboro plants in North Carolina. The Company has also retired eight of its eleven North Carolina coal plants lacking environmental controls, and plans to retire the remaining three plants by the end of 2013, in conjunction with the operation of the new Sutton CC plant. The Company's installation of scrubbers and SCRs has resulted in significant reductions in SO_2, nitrogen oxide, and mercury emissions. As a result of the installation of environmental controls, the construction of natural gas-fueled combined cycle plants, and the retirement of unscrubbed coal-fired plants, the Company's emissions profile will be significantly reduced as its fuel diversity is simultaneously strengthened. The Company's investment in new generation has enabled it to address growing environmental constraints and to take advantage of favorable prices for U.S. natural gas as well as improvements in combined-cycle technology.

Witness Yates also testified regarding the additional expenses the Company has experienced related to the operation of its nuclear fleet. The Company has included increased operating and maintenance (O&M) expenses in this case to reflect increased costs of compliance with new requirements issued by the Nuclear Regulatory Commission (NRC), increased staffing requirements, and increased collections for end-of-life reserves to cover costs to retire the Company's nuclear facilities.

Witness Yates testified that the Company has incurred increased costs to comply with the requirements issued by the NRC in response to the March 2011 event in Fukushima, Japan. The NRC continues to evaluate and act on the lessons learned from this incident and issued near-term requirements in March 2012 to ensure that appropriate safety enhancements are implemented at nuclear power plants in the U.S. In response to these requirements, the Company has developed a Fukushima Response Program. The Company has incurred expenses to plan, design, and execute compliance measures and anticipates ongoing staffing additions of operations and maintenance personnel to support the expanded requirements resulting from the new regulations. Witness Yates testified that the Company is also experiencing higher costs related to NRC rules governing cyber security. The Company has only included in this case costs related to NRC regulations that are known and measurable, but expects that its annual compliance expenses will further increase as additional requirements from the NRC are forthcoming.

Witness Yates also explained the Company's need to hire additional staff at its nuclear facilities. Based on recent analyses conducted on behalf of DEP, the Company's peers and top quartile performers have higher staffing levels. This issue is exacerbated when one considers that due to the age of the nuclear workforce the industry is challenged to develop a pipeline of skilled employees. The Company is committed to investing in its nuclear plants and employees to ensure continued safe, and improved, performance. To that end, the Company plans to add staff positions for the Company's Brunswick, Robinson, and Harris nuclear generating facilities and related support organizations.

Witness Yates stated that the Company has also experienced increased pension and other post-employment benefits (OPEB) costs, resulting from continued declines in discount rates, decreases in the expected long-term return on plan assets, the five year market-smoothing of pension plan asset losses occurring in 2008, and increases in health care medical costs for the OPEB plans.

Witness Yates also described the Company's increased expenses related to improving the reliability of the Company's power delivery system, specifically through implementing changes to its vegetation management program. The Company's Vegetation Management Plan was filed with the Commission on April 13, 2012, in Docket No. E-2, Sub 1010. The Company maintains more than 70,000 miles of transmission and primary distribution lines in the Carolinas, and it is costly to maintain such a large system. During the test period, the Company switched to a cyclical approach to lower voltage transmission line vegetation management, and determined that a change on all transmission voltages to a three-year side-trimming cycle (from the planned six-year cycle) with additional off right-of-way danger tree cutting was necessary to ensure reliability. The change to a three-year side-trimming cycle with danger tree cutting for transmission was necessary to address conductor blow-out design clearance issues on existing rights-of-way, to ensure compliance with NERC clearance requirements for 230/500 kV lines, and to maintain lower voltage transmission to the same practices and standards to ensure high levels of reliability. Also, at the time of the switch, the Company had started to see degradation in its reliability and an increase in vegetation-related outages. Mr. Yates testified that the new cyclical approach will ensure the reliability of the Company's distribution system by minimizing vegetation-related interruptions, while also maintaining compliance with regulatory, environmental, and safety requirements in a manner that enhances safety for the public and its customers, as well as employees and contractors.

Witness Yates also described the Company's cost containment efforts. The Company's customers are receiving the benefit of savings related to Progress Energy Corporation's merger with Duke Energy. In addition to the savings customers are realizing through the two merger-related decrement riders implemented on September 1, 2012, the Company is including merger-related savings in this request related to its Voluntary Severance Program (VSP), net of certain costs to achieve. Also, through its Continuous Business Excellence initiative, the Company is identifying opportunities to improve operations and cut costs, and is developing sustainable process improvements to benefit customers and shareholders over the long term. The Company also provides demand-side management (DSM) and energy efficiency (EE) programs to its customers, which provide incentives to invest in efficiency improvements, and include customer education and outreach efforts to help customers better understand and manage their energy use.

Witness Yates explained that the Company is very mindful of the fact that it is asking to increase its base rates at a time when many of its customers are struggling. He explained that electric service provided by DEP is still a good value for customers, who have paid the same base rate for electricity for the last 25 years. Witness Yates noted that even with the increase proposed in this case, customers will continue to pay electric rates that are well below the national average. The requested increase should allow the Company to maintain a financially strong position and ensure that financing costs remain reasonable as the Company continues its modernization program. Both witness Yates and Company witness De May testified that the Company must remain attractive to the financial community in order to access the capital it needs on reasonable terms for the benefit of the Company's customers. According to witness Yates, the Company needs to update its rates to reflect the true costs of providing service to its customers and maintain the ability to balance those needs with the requirements of investors who provide the reasonably priced capital upon which the Company relies.

The Stipulation

On February 25, 2013, the Public Staff filed a Notice of Settlement in Principle. On February 28, 2013, DEP and the Public Staff entered into and filed an Agreement and Stipulation of Settlement, a corrected version of which was filed on March 6, 2013, resolving most of the issues in this proceeding between the two parties. The Stipulation is based upon the same test period used by the Company in the Application, with updates. On March 14, 2013, DEP and the Public Staff filed an Amendment to the Stipulation withdrawing the Company's request to include DSDR in base rates. On March 19, 2013, the Stipulating Parties filed a Second Amendment to the Stipulation agreeing to strike the reference to Rider 7 in paragraph 5.B.(5).

The Public Staff also filed direct testimony on February 28, 2013, recommending and supporting certain settlement adjustments to the Company's requested revenue increase, as modified by the Company's supplemental filings, set forth in Revised Hoard Exhibit 1 and Revised Settlement Agreement 1. The Company filed testimony in support of the Stipulation on March 14, 2013, accepting or choosing not to contest the settlement adjustments recommended by the Public Staff.

Company witness Newton testified that the Stipulation is the product of extensive give-and-take negotiations between the Company and the Public Staff. He and Public Staff witness Hoard stated that while the Stipulating Parties believe that the Stipulation represents a just and reasonable resolution of the issues in this case, the agreed-to resolution of issues does not necessarily reflect specific positions asserted by the Stipulating Parties, or the position any of these parties would take if this matter were fully litigated. Witness Newton emphasized that the Stipulation represents a compromise of a complex set of issues; and thus, the various provisions of the Stipulation are interrelated. He noted that it is important that the Stipulation be accepted in its entirety. The Stipulation provides that it is binding upon the Stipulating Parties only if the entire agreement is approved by the Commission.

As summarized by witness Newton, the key provisions of the Stipulation are as follows:

1. The Stipulation includes a two year step-in to the total agreed upon rate increase, with rates anticipated to be effective June 1, 2013. This step-in would occur through the agreement of the Company to delay its collection of the financing costs on CWIP for the new Sutton CC for one year.

2. The rate increase in Year One is approximately $147 million, or an average of 4.6%.

3. The rate increase in Year Two is approximately an additional $32 million, or an average of 0.9%, for a total rate increase of 5.5%.

4. The Stipulation is based upon an ROE of 10.20% and a 53% equity component of the capital structure.

5. The Company will convert $20 million of a regulatory liability for the benefit of the Company's North Carolina retail customers to be allocated among (a) local agencies and organizations for programs that provide assistance to low-income customers and (b) programs that provide training to improve worker access to jobs and increase the quality of the workforce.

6. The Stipulation withdraws the Company's request to include the costs of its DSDR program in its base rates. This withdrawal resolves the issues raised by Intervenors in connection with the Company's initial request.

Company witness O'Sheasy explained that for the purposes of settlement, the Company and the Public Staff agreed to various rate design changes to effectuate the recommended rate increases to all rate classes. He testified that he believes that the agreed-upon provisions represent a reasonable compromise of the issues in the context of the settlement. In summary, the key rate design provisions in the Stipulation include increased basic customer charges, a new time-of-use (TOU) rate design for residential customers, a study of the Company's TOU schedules and inputs associated with those schedules for each customer class, consolidation of the Company's standby service riders, consolidation of the Company's large load curtailment riders, and implementation of minimum bill provisions for certain rate classes.

With respect to the Company's low-income customers, witness Newton testified that the Company realizes that they are struggling during these difficult economic times. Accordingly, DEP agrees in the Stipulation to convert a $20 million regulatory liability into funds to benefit low-income customers and work force development in North Carolina. This is in addition to the

$20 million of similar assistance that the Company agreed to commit to low-income assistance in connection with the recently completed merger between its parent company and Duke Energy. The Stipulating Parties agree that the low-income assistance and work force development funds committed pursuant to the Stipulation will be contributed by January 1, 2014, and that the Company will consult with the Public Staff and submit a specific proposal for distribution of the funds within 60 days of this Order for Commission review and approval.

As the Stipulation has not been adopted by all of the parties to this docket, its acceptance by the Commission 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 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).

The Commission finds and concludes that the Stipulation is the product of the give-and-take of the settlement negotiations between DEP and the Public Staff in an effort to appropriately balance the Company's need for rate relief with the impact of such rate relief on customers. It is, therefore, material evidence to be given appropriate weight in this proceeding.

EVIDENCE IN SUPPORT OF FINDINGS OF FACT AND CONCLUSIONS NOS. 9-22

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

The Stipulation provides for a two year step-in increase in DEP's electric sales revenues from its North Carolina retail electric operations. In the first year, the Stipulation provides for an approximate increase in rates of $147 million. In the second year, the Stipulation provides for an additional increase in rates of approximately $32 million, for a total increase of approximately $179 million. The Stipulating Parties agree that these revenues are intended to provide DEP, through sound management, the opportunity to earn an overall rate of return of 7.55%. This overall rate of return is derived from applying the Company's long-term debt cost of 4.57% and a rate of return on common equity of 10.20% to a capital structure consisting of 47% long-term debt and 53% common equity.

Return on Equity

The Company requested approval for its rates to be set using an ROE of 11.25% in its Application. The Stipulation provides for an ROE of 10.20%.

1. Evidence from expert witnesses on cost of equity capital

Company witness Hevert recommended in his direct testimony an ROE of 11.25%, which was slightly above the midpoint of his recommended range of 10.50% to 11.50%. Witness Hevert's direct testimony explained the importance of a utility being allowed to earn an ROE that is adequate to attract capital at reasonable terms, under varying market conditions, and that will enable the utility to provide safe, reliable electric service while maintaining its financial integrity. Witness Hevert explained that unlike the cost of debt, the cost of equity is neither contractual nor observable, and must be estimated based on market data. Witness Hevert primarily used the Constant Growth Discounted Cash Flow (DCF) model and considered, as a check on his DCF, the results of the Capital Asset Pricing Model (CAPM) in determining his ROE recommendation. Witness Hevert provided extensive testimony concerning the capital market environment, and addressed the effect those market conditions have on the return investors require in order to commit their capital to equity securities. Witness Hevert also considered economic conditions as they affect the Company's customers in North Carolina. He noted that while the unemployment rate in North Carolina was higher than the national rate, other indicia of economic health were better in North Carolina than in the nation as a whole. For example, Hevert testified that the State's household income growth is expected to outpace the national average over the coming five years. Hevert indicated further that:

> North Carolina's compound annual real Gross Domestic Product (GDP) growth over the most recent one, five, and ten year periods (*i.e.*, 1.84 percent, 0.83 percent, and 1.86 percent) has been consistently higher than the national average (1.47 percent, 0.36 percent, and 1.44 percent). Similarly, the state's kilowatt-hours sales growth rates over the same time periods (1.30 percent, 1.23 percent, and 6.86 percent) have been higher than the national average (0.93 percent, 0.51 percent and 4.38 percent). However, over the past ten years, the cost of electricity in North Carolina has generally grown at a slower pace than the national average such that 2010 residential prices (10.12 cents/kWh) were approximately 12.31 percent below the average price in the U.S. (11.54 percent).

(T, Vol. 1, pp. 256-57) Accordingly, witness Hevert concluded, "the regional economic conditions in North Carolina were substantially similar to the United States, such that there is no direct effect of those conditions on the Company's cost of equity." (Id., p. 256.)

In addition to capital market risks, witness Hevert considered several business risks specific to DEP in determining his recommended ROE of 11.25%, including: (1) the Company's large coal-fired generation portfolio; (2) the Company's nuclear generation portfolio; and (3) flotation costs associated with equity issuances. Witness Hevert also described how current capital market conditions, including historically low Treasury yields, incremental credit spreads, yield spreads and equity market volatility and return correlation have affected the Company's ROE. In his direct testimony, witness Hevert concluded that those factors suggested an ROE above the midpoint of his range.

Public Staff witness Johnson also provided testimony regarding the Company's cost of equity. Witness Johnson testified in support of the 10.20% ROE in the Stipulation. Witness Johnson explained that the Stipulation allows an overall rate of return of 7.55% based on a 10.20% ROE and a capital structure of 53% equity and 47% long-term debt. The overall rate of return in the Stipulation is 25 basis points lower than the overall rate of return that the Commission approved in Dominion North Carolina Power's (DNCP) recent rate case, Docket No. E-22, Sub 479 (DNCP Rate Case). Witness Johnson explained that the 10.20% ROE falls just below the mid-point of his comparable earnings analysis.

Public Staff witness Johnson utilized both a comparable earnings approach and a market approach to estimate ROE. Witness Johnson explained that he arrived at an ROE range of 9.75% to 10.75% under the comparable earnings approach. Under the market approach, Johnson arrived at an ROE range of 7.72% to 8.95%. The stipulated 10.20% ROE falls within Johnson's range using the comparable earnings approach, but not within the range he developed under the market approach. Witness Johnson testified that a 10.20% ROE and a 7.55% overall rate of return is reasonable within the context of the Stipulation because it falls within the range of the evidence. Witness Johnson concluded that a 10.20% ROE is reasonable and consistent with the public interest because the return is being used in the context of a settlement of numerous other issues, resulting in a rate increase of less than half of what the Company originally requested.

Company witness Hevert also provided testimony in support of the 10.20% ROE in the Stipulation. Witness Hevert testified that although the stipulated ROE is below the lower bound of his recommended range, he recognized that the Stipulation represents the give-and-take among the parties with respect to multiple issues that would otherwise be contested. Witness Hevert testified that he appreciated and respected the Company's determination that the terms of the Stipulation, taken as a whole, are such that the Company will be able to raise the external capital necessary to continue the investments required to provide safe and reliable service, and that it will be able to do so when needed and at reasonable cost rates.

In his prefiled direct testimony, CUCA witness O'Donnell recommended an ROE of 9.25%. Witness O'Donnell also testified that he was concerned that DEP may be downgraded by rating agencies if the Commission approves the stipulated rate increase, citing the Company's industrial rates compared to select regional peers. However, witness O'Donnell noted on cross examination that in light of CUCA's position regarding the Stipulation the only parts of his prefiled direct testimony that "would be applicable [in this proceeding] are rate design and Rider IER." (T, Vol. 3, p.162.)

Company witness Hevert rebutted CUCA witness O'Donnell's initial ROE recommendation. Witness Hevert disagreed with many aspects of witness O'Donnell's ROE analysis and recommendation. Principally, witness Hevert disagreed with witness O'Donnell's: (1) proxy group selection criteria and comparison companies; (2) growth rate estimates used in witness O'Donnell's DCF models; (3) criticisms of the CAPM method; and (4) characterization of the effect of current capital market conditions on the Company's cost of equity. Witness Hevert also noted that witness O'Donnell failed to reconcile his recommended ROE with the 10.20% ROE authorized by this Commission two months ago in the DNCP Rate Case. Witness Hevert testified that his research indicated that witness O'Donnell's recommendation would equal the lowest return authorized for a vertically integrated electric utility in at least 30 years. Therefore, even putting aside analytical differences, witness Hevert found witness O'Donnell's recommendation to be unreasonably low.

Company witnesses De May and Hevert also disagreed with witness O'Donnell's assertion that DEP will be downgraded if the current rate increase is granted. Witnesses De May and Hevert testified that, in fact, a denial of this rate increase would be far more damaging to the Company's credit quality. According to witnesses De May and Hevert, the consistency of regulation and the extent to which regulatory decisions support utilities' financial integrity are important considerations from the perspective of investors, and the Stipulation supports these goals.

Commercial Group witnesses Chriss and Rosa provided testimony regarding the 11.25% ROE recommendation contained in witness Hevert's direct testimony. Witnesses Chriss and Rosa did not recommend a specific ROE. Rather, they observed that the 11.25% recommendation contained in witness Hevert's direct testimony exceeds the range of recently authorized ROEs across the country, which, according to data from SNL Financial, have been in the range of 9.25% to 10.50%, with an average authorized return of 10.00%.

After the Stipulation was filed, witnesses Chriss and Rosa filed testimony acknowledging that the Stipulation provides for significant movement on the Commercial Group's concerns regarding ROE. However, the Commercial Group declined to support the Stipulation because of concerns regarding the Company's proposed Rider SS.[1]

In his rebuttal testimony, Company witness Hevert responded to the Commercial Group's analysis of authorized returns in other jurisdictions by noting that several of the utilities included in the data from SNL Financial were transmission and distribution-only (T&D) utilities, not vertically integrated[2] utilities like DEP. Witness Hevert testified that after removing the T&D utilities from the data, the median authorized ROE for the remaining vertically integrated

[1] The Commercial Group also contested the Company's proposal to move the costs of its DSDR program into base rates. However, the Company subsequently withdrew this request through the March 14, 2013, Amendment to the Stipulation.

[2] A vertically integrated utility owns and operates the generation, transmission, and distribution facilities.

utilities included in Commercial Group Exhibit CR-3 was 10.20%, which is exactly equal to the stipulated ROE. Witness Hevert also noted that the Settlement ROE is consistent with the mean and median returns recently awarded to utilities in jurisdictions that are considered to be credit supportive.

Witnesses Hevert and Johnson both testified in the recently concluded DNCP Rate Case, Hevert for DNCP and Johnson for the Public Staff. The methodologies that they followed in that case were virtually the same as the methodologies that they followed in this case. The DNCP Rate Case was fully contested, so the Commission necessarily weighed their respective analyses in reaching an independent determination of the 10.2% ROE allowed by the Commission in that proceeding.

In the DCNP Rate Case, the Commission critiqued several aspects of witness Hevert's testimony. First, the Commission had questions concerning his proxy group selection, and, second, the Commission was not convinced that the "business risks" Hevert identified were of sufficient magnitude to push the utility's required ROE to the upper portions of his ROE range. The Commission did, however, give weight to Hevert's DCF analysis indicating that the required ROE ranged from 10.14% to 10.38% when measured by mean growth rates after he made certain adjustments to his proxy group composition. Order Granting General Rate Increase, Docket No. E-22, Sub 479 (December 21, 2012) (DNCP Rate Order), at 112, 114. The Commission ultimately concluded that 10.20% was the appropriate ROE for DNCP. Further, 10.20% is squarely within witness Hevert's DCF range.

Witness Johnson's testimony in the DNCP Rate Case, as in this case, examined ROE through two methods, the comparable earnings method and a market approach. The Commission questioned the results of his market approach, finding that those results would have placed DNCP's cost of equity at a level below "any authorized ROE determination for a vertically-integrated electric utility like DNCP by any Commission in the last 30 years," and that "the weight of the evidence" simply does not support such a conclusion. (Id. at 113.) The Commission did, however, give weight to Johnson's comparable earnings approach, which resulted in an ROE range of 9.75% to 10.75%.

In this case, witness Hevert testified in response to cross examination questions from the Attorney General that DEP and DNCP "are in many ways very similar," and agreed that they "are fairly representative of one another in terms of their risk profiles" (T, Vol. 1, pp. 370-71.) This testimony is credible and uncontested, and the Commission gives it substantial weight.

In his rebuttal testimony in this case, witness Hevert took note of the concerns the Commission expressed regarding his DNCP Rate Case analysis. In particular, he re-analyzed his DCF results after reducing the growth rate for one of his proxy group members in light of the Commission's concerns expressed in the DNCP Rate Order about the effect that the dramatic increase in the forecasted growth rate for that company had upon his analysis. (See DNCP Rate Order at 112.)[1] Witness Hevert's re-analyzed results are presented in his Table 4: Summary of

[1] The Commission indicated in the DNCP Rate Order that this did not show a flaw in witness Hevert's analysis, but merely that in light of the relatively small size of witness Hevert's proxy group the forecasted growth increase had contributed to an "inordinate" influence on the outcome of the analysis. (Id.)

Constant Growth DCF Results. The results shown for "mean growth rate" forecasts are depicted on the basis of both the "Proxy Group Mean" (ranging from 10.03% to 10.17%) and the "Proxy Group Median" (ranging from 9.97% to 10.52%). Averaging all of the numeric results together, the resulting sum is 10.19%. The North Carolina Supreme Court has long recognized that a "zone of reasonableness extending over a few hundredths of one percent" exists within which the Commission may appropriately exercise its discretion in choosing a proper ROE. State ex rel. Utils. Comm'n v. Gen. Tel. Co. of the Southeast, 285 N.C. 671, 681, 208 S.E.2d 681, 687 (1974). Accordingly, the Commission finds that witness Hevert's testimony and his DCF analysis, and in particular his analysis on the basis of mean growth rates, provides substantial support for an ROE of 10.20%.

Witness Johnson analyzed the Company's cost of equity under the comparable earnings method and a market approach, just as he did in the DNCP Rate Case. His comparable earnings result indicates a range of 9.75% to 10.75%, and the stipulated ROE of 10.20% is almost at the mid-point (indeed, slightly below the mid-point) of that range. Witness Johnson's market approach, however, produced a range of 7.72% to 8.95%. Again, these levels are low in relation to authorized ROEs previously approved by this Commission. As witness Hevert pointed out with specific reference to witness O'Donnell's 9.25% ROE recommendation, an ROE at that level would equal the lowest return authorized for a vertically integrated electric utility in at least 30 years. No evidence before this Commission supports the proposition that the Company is so much less risky than other vertically integrated electric utilities with which the Company is obliged to compete for capital. Accordingly, as in the DNCP Rate Case, while the Commission believes that witness Johnson's comparable earnings approach is entitled to substantial weight, the Commission believes that his market approach as presented in this proceeding is unpersuasive.[1]

The Commission cannot blindly follow ROE results allowed by other commissions. Rather, the Commission 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, DEP must compete with utilities in other jurisdictions for investors. In this connection, the analysis performed by Commercial Group witnesses Chriss and Rosa, as modified by witness Hevert, is instructive. Chriss and Rosa noted that according to data from SNL Financial, recently authorized ROEs across the country have been in the range of 9.25% to 10.50%, with an average authorized return of 10.00%. Witness Hevert extracted from the data reviewed by witnesses Chriss and Rosa those companies that were T&D utilities, not vertically integrated utilities, like DEP. Witness Hevert testified that after removing the T&D utilities from the data the median authorized ROE for the remaining vertically integrated utilities included in Commercial Group Exhibit CR-3 was 10.20%, which is equal to the stipulated ROE. In addition, as witness Hevert noted, North Carolina is generally viewed by the credit ratings agencies to be a credit supportive jurisdiction, and an ROE of 10.20% is consistent

[1] The Commission emphasizes that its consideration of the various ROE witness's analyses, its weighing of expert evidence, and its findings and conclusions concerning the methodologies it finds more acceptable all are limited to this case. In a different case, with different facts and circumstances, the Commission may well come to different conclusions.

with the mean and median returns recently awarded to utilities in jurisdictions that are considered to be credit supportive.

In complying with the Supreme Court's mandate in CUCA I that the Commission evaluate all of the testimony in determining the appropriate ROE, it remains for the Commission to consider the testimony of CUCA witness O'Donnell. As noted previously, O'Donnell's pre-filed direct testimony recommended an ROE of 9.25%. However, when testifying at the evidentiary hearing, witness O'Donnell in effect disavowed reliance upon those portions of his testimony except for rate design and Rider IER. Accordingly, the Commission gives only very limited weight to witness O'Donnell's ROE recommendation in the selection of an appropriate ROE. The Commission may take into account in its evaluation of testimony the witness' own position with respect to the weight the witness places on that testimony. See e.g., State ex rel. Utilities Commission v. Public Staff-North Carolina Utilities Commission, 331 N.C. 215, 225, 415 S.E.2d 354 (1992) (striking down Commission finding of 13.2% ROE, the Court noted that the only evidence of ROE higher than 13% was risk premium study by one expert, but that expert's own testimony indicated that the risk premium approach had been used "merely as a 'check' on his DCF studies, was 'not as good as the DCF.'") Further, as a result of Witness O'Donnell's withdrawal of his ROE testimony, O'Donnell was not subject to cross-examination regarding his ROE recommendation. Therefore, the Commission gives only very limited weight to his recommendation in the selection of an appropriate ROE.

In addition, witness O'Donnell's insistence in his pre-filed direct testimony that approval of the stipulated rate increase, which is predicated upon a 10.20% ROE, may lead to the Company being downgraded by rating agencies casts doubt on his overall conclusions. The factual basis for O'Donnell's opinion is the September 2011 downgrade of South Carolina Electric & Gas (SCE&G) by Moody's. According to O'Donnell, Moody's took this action in part because of high rates in comparison to its neighboring utilities. However, SCE&G's rate levels do not appear to be the driver for Moody's downgrade. Rather, as Moody's itself reported, the downgrade reflected heightened financial risk associated with SCE&G's nuclear construction program. Thus, O'Donnell's testimony fails to address in detail the actual basis for Moody's downgrade of SCE&G, and this failure negatively affects the Commission's acceptance of O'Donnell's testimony generally. In any event, as previously indicated, acceptance by this Commission of his 9.25% ROE recommendation would mean that the Commission would have accepted an ROE at a level equal to the lowest return authorized for a vertically integrated electric utility in at least 30 years, without any evidence showing that the Company is so much less risky than other vertically integrated electric utilities with which it competes for capital.

Finally, as the Supreme Court made clear in CUCA I (348 N.C. at 466) and CUCA II (351 N.C. at 231), the Commission should give full consideration to a non-unanimous stipulation as appropriate evidence, along with all other evidence presented by the parties, in determining whether the Stipulation's provisions should be accepted. In this case, insofar as expert ROE testimony is concerned, none of the expert witnesses presented any evidence to the effect that the stipulated 10.20% ROE level was unacceptable. Both witnesses Hevert and Johnson supported the Company's required ROE at that level, in the context of the Stipulation as a whole, and witness Hevert was subjected to extensive cross-examination. In contrast, witness O'Donnell indicated that his pre-filed direct testimony regarding ROE "no longer applied" in light of CUCA's position regarding the Company's settlement with the Public Staff. No other party submitted expert ROE testimony. No party sought to cross-examine witness Johnson, and no party cross-examined witness O'Donnell on his statement that his pre-filed ROE testimony no longer applied, or on any aspect of his ROE opinion. Thus, the Commission finds and concludes that the Stipulation itself, along with the expert testimony of witnesses Hevert and Johnson, as discussed above, is credible evidence of the appropriate ROE and is entitled to substantial weight in the Commission's ultimate determination of this issue.

2. Impact of changing economic conditions on customers

On April 12, 2013, the North Carolina Supreme Court decided State ex rel. Utils. Comm'n v. Attorney General Roy Cooper (Cooper), ___ N.C. ___, 739 S.E.2d 541 (2013). The Supreme Court reversed and remanded the Commission's ROE decision in Duke Energy Carolinas, LLC's 2011 Rate Case. See Order Granting General Rate Increase, Docket No. E-7, Sub 989, at 28 (January 27, 2012). (Duke Rate Order). In the Duke Rate Order, the Commission approved a stipulation between Duke Energy Carolinas and the Public Staff calling for a 10.50% ROE. In its decision, the Supreme Court held that:

> (1) it did not appear that the Commission made its own independent analysis and conclusion, as required by CUCA I, that a 10.50% ROE was appropriate; and
>
> (2) 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.

As set forth above, the Commission has independently evaluated and weighed the expert ROE evidence together with the Stipulation in the present case, and finds and concludes as a result of that evaluation that the 10.20% stipulated ROE is just and reasonable. The Commission's review also includes consideration of the evidence presented by all parties in connection with the impact of changing economic conditions on customers of the Company, as set forth below.

In considering the impact of changing economic conditions on customers, the Commission must perform its analysis and reach a conclusion that is consistent with the United States Constitution, the North Carolina Constitution and the Public Utilities Act. As the North Carolina Supreme Court has held,

> [T]he Legislature intended for 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, Sec. 19, being the same in this respect.

State ex rel. Utils. Comm'n v. Pub. Staff-N. Carolina Utils. Comm'n, 323 N.C. 481, 490, 374 S.E.2d 361 (1988). There are constitutional constraints upon the Commission's ROE decision, as the United States Supreme Court's decisions in Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia, 262 U.S. 679 (1923) (Bluefield), and Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944) (Hope) make clear. 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 nonetheless 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 (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.

In his Brief, the Attorney General notes that in Cooper the North Carolina Supreme Court held, among other things, that "in retail electric service rate cases the Commission must make findings of fact regarding the economic impact of changing economic conditions on customers when determining the proper ROE for a public utility." State ex rel. Utils. Comm'n v. Cooper, ___ N.C. ___, 739 S.E.2d 541, 548. In the present case, the Attorney General contends that the rate of return expert witnesses failed to adequately consider all requisite statutory factors for establishing an ROE that is fair to consumers as well as investors. The Attorney General argues that the testimony of the expert witnesses shows that customer interests did not factor into their ROE recommendations, other than, at most, indirectly or as afterthoughts. Therefore, the Attorney General states that the Commission cannot legally make a proper determination as to a fair and reasonable ROE. The Attorney General believes that a review of witness Hevert's testimony demonstrates that he failed to adequately consider or factor in economic conditions on customers when establishing his ROE recommendation and that he offered no explanation as to how his analysis and recommendation balanced the interests of customers and investors. In addition, the Attorney General states that an examination of the remaining record shows that other ROE witnesses likewise did not adequately consider impacts on consumers. Thus, the Attorney General argues that the record is insufficient to allow the Commission to render a decision regarding a rate of return that is fair to both customers and investors. Therefore, the Commission should reject the Stipulation and deny the Company's request for a rate increase.

The Commission disagrees with the Attorney General, for two reasons. First, the Supreme Court's holding in Cooper does not adopt the Attorney General's position on this point. Indeed, the Court did not hold that the ROE evidence in that case was deficient. Rather, it held that the Commission appeared to have adopted the ROE in the Stipulation instead of making an independent analysis of the ROE evidence and reaching its own conclusion on the proper ROE. In addition, the Court held that in making its independent analysis and conclusion the Commission must consider the impact of the ROE on consumers and make findings of fact about that impact. However, the Court did not hold that the ROE expert witnesses must consider the impact of changing economic conditions on consumers in their analyses in order for their evidence to be sufficient.

Second, the testimony of witnesses Hevert and Johnson, which deserve great weight, addresses changing economic conditions at some length. As noted above, in his direct testimony witness Hevert considered economic conditions in North Carolina. He noted that while the employment rate in North Carolina was higher than the national rate, other indicia of economic health were better in North Carolina that in the nation as a whole. Witness Hevert compared the State's expected household income growth, GDP, and kWh sales, to the national average and concluded that "the regional economic conditions in North Carolina were substantially similar to the United States, such that there is no direct effect of those conditions on the Company's cost of equity." (T, Vol. 1, pp. 256). In the course of cross-examination by the Attorney General, witness Hevert testified concerning changing economic conditions as they affect customers, as follows:

> Q . . . Mr. Hevert, in coming up with your ROE range and your recommendation, did you factor into your analysis how changing economic conditions are affecting . . . DEP's customers? . . .
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> A (Mr. Hevert) . . . [I]n the testimony here we did review economic conditions in North Carolina relative to the rest of the country looking at unemployment, real GDP growth, relative electric rates so yes, we did take that into consideration.
>
> Q Okay. Can you – can you tell me how specifically you took that – those factors into consideration?
>
> A (Mr. Hevert) Let me – well, I guess we – I looked at – looked at those factors, looked at the rate of unemployment in North Carolina relative to the country, it's somewhat higher in North Carolina; looked at the rate of 1-, 5-, and 10-year real gross domestic product growth, it was higher in North Carolina; looked at the level of retail electricity rates relative to the balance of the country, it's lower in North Carolina; and on balance, based on those specifics, based on those metrics, concluded that I didn't find reason to make an adjustment one way or another.

(T, Vol. 1, pp. 391-92) Thus, witness Hevert provided evidence that changes in the economic conditions affecting customers in North Carolina were not so different from changes in economic conditions affecting utility customers generally in the United States, and therefore did not merit any adjustment to his ROE analysis.

Similarly, witness Johnson indicated in his Appendix B that the Commission is required to fix rates that are fair to both the utility and the consumers. He testified the state of the economy is relevant to both sides of that balancing effort.

Witness Johnson also testified as to the extraordinary events occurring in the financial markets and the broader economy from 2007 to the March 2013 evidentiary hearing. He stated that within the past century the only really comparable period of prolonged weakness was during the 1930's, which came to be known as the Great Depression. Witness Johnson further testified that although the National Bureau of Economic Research declared the recession officially ended in June 2009, the improvement in the economy has been both weak and very slow, and firms are still reluctant to expand or invest despite extremely low interest rates.

In this case, all parties had the opportunity to present the Commission with evidence concerning changing economic conditions as they affect customers. The Attorney General presented no ROE evidence. However, he submitted AG Bateman Cross Examination Exhibit 1, which indicated that the Company's revenue requirement as set out in the Stipulation would be reduced by in excess of $50 million if witness O'Donnell's 9.25% ROE were adopted. However, the Commission has concluded that witness O'Donnell's ROE testimony, having been disavowed and not subjected to cross-examination, deserves only very limited weight in the

Commission's ROE determination. Indeed, the lowest recommended returns and the lowest results from the witnesses' economic models would, in the Commission's judgment, leave the Company with less revenue than necessary to pay for its reasonable costs, including the cost of equity capital.

Finally, NC WARN takes the position in its Brief that the Commission should deny the Company's application to increase rates, as modified by the Stipulation. Further, in one of NC WARN's four recommended alternatives it contends that the increased residential Basic Customer Charge (BCC) lowers DEP's risk of collecting revenue for its residential services and that this lowered risk should be reflected in a lower ROE. However, NC WARN made no suggestion as to what the lower ROE should be and cited no evidence supporting the quantification of such an adjustment to the ROE. Thus, any adjustment to the ROE on this basis would be pure speculation. In addition, the Commission regards any increase in the BCC as a rate design issue, not an ROE issue.

In the Duke Rate Order, the Commission stated:

> In his brief, the Attorney General first argued that there is insufficient evidence in the record to allow the Commission to establish a reasonable return pursuant to G.S. 62-133 because the expert witnesses failed to consider the impact of changing economic conditions on consumers when making the ROE analyses and recommendations. However, the Commission does not find this argument persuasive. Duke witness Hevert and Public Staff witness Johnson testified that it is not necessary to consider the impact of changing economic conditions on consumers in the context of an ROE economic analysis, other than in a broader macroeconomic sense, when analyzing changing market conditions for the purpose of making ROE recommendations. However, the Commission is required to consider the economic effects of its ROE decision on a public utility's customers pursuant to G.S. 62-133(b)(4). In particular, G.S. 62-133(b)(4) states, in pertinent part, that in fixing rates the Commission must fix a rate of return on the utility's investment that "will enable the public utility by sound management to produce a fair return for its shareholders, considering changing economic conditions and other factors, including, but not limited to…to compete in the market for capital funds on terms that are reasonable and that are fair to its customers and to its existing investors." One of the "terms" on which a public utility competes in the market for capital funds is the utility's authorized ROE. Thus, the Commission must consider whether that term is reasonable and fair to the utility's customers.

Duke Rate Order, at 28.

The Commission's DNCP Rate Order included a very similar statement. DNCP Rate Order, at 113-114. Moreover, in both the Duke and DNCP rate cases, the Commission obtained extensive evidence regarding the impact on the utilities' customers of changing economic conditions by holding several public witness hearings. Consistent with that requirement in this case, the

Commission held five evening hearings throughout DEP's North Carolina service territory to receive public testimony. The testimony presented at public hearings illustrates in detail the difficult economic conditions facing customers. The Chairman of the Commission expressly noted at the conclusion of the public hearings that customer testimony was recorded, "and will become an official part of this case and we will consider it with the other testimony when we render a decision after all the evidence has been submitted." (See T, Rockingham, p. 22.)

Of the 1.2 million DEP retail customers in North Carolina, 127 customers testified at the hearings for public witnesses. Of that total, 58 customers testified that the rate increase was not affordable to many customers, including the elderly, persons on fixed incomes, persons with disabilities, persons unemployed, persons underemployed, and the poor. A sampling of that customer testimony is summarized below. Another significant group of customers expressed the view that the Company should be required to discontinue its fossil fuel and nuclear generation in favor of energy efficiency and renewables, even if reliance on renewables is more expensive.

Bob Cozart of Asheville explained how poor people are victimized in many ways. Not only do they spend a disproportionate amount of their income on the basic necessities, they reside in cheap housing such as trailers, old houses or buildings that are much more costly to heat or cool. It is not uncommon for poor customers to see a monthly utility bill of $300 in the middle of winter.

Greg Borom testified that the local referral line for the Children First/Communities in Schools of Buncombe County received over 9,200 requests for housing and utility needs in 2012. He also testified that over half the school children in Buncombe County receive free lunch and reduced lunch, and their families struggle to meet the basic needs of housing, healthcare, transportation and food. He requested that the Company's rate proposal not place more hardship on these children because their parents will have to choose between food and electricity or heat. Similarly, Kelly Martin testified that over 15% of the individuals in Buncombe County are living in poverty.

Greene County Commissioner Denny Garner testified that Greene County is one of the most impoverished counties in North Carolina with approximately 20% of its citizens living below the poverty level, and Charles Wright of Goldsboro testified that eastern North Carolina has nearly 21% of its people living in poverty.

Joseph Kearns of Marston in Richmond County testified that he lives in a small community of approximately 30 households, in which nearly 90% of the people are retired, or on a fixed income, and many have disabilities. He testified in this current economic situation, they are having a difficult time paying utility bills.

Antonio Blue, the mayor of the Town of Dobbins Heights in Richmond County, testified that the average income of the approximately 855 in Dobbins Heights is $12,000 to $13,000, and most people are on fixed incomes, either retired or disabled. Mayor Blue inquired how his citizens, who can hardly pay their bills now, will be able to afford to pay their bills when the proposed increase comes.

Jesse Hannible of Wilmington testified that people come to his non-profit civic organization all the time for funds to help pay their utility bills. Carol Swift of Wilmington testified that she owns rental houses in Wilmington and on numerous occasions in the past two years, due to the economic environment, she actually had to reduce rents so her tenants could stay in their homes. She stated if her tenants receive an electric rate increase, there is no way the tenants are going to make it.

Karen Mallem of Siler City testified that the Company's proposed rate increase is regressive and unconscionable given the high unemployment rate in North Carolina of 9.4%, ranking North Carolina 47th of 50 states. Wanda Webb Schrader of Raleigh testified that North Carolina has over one million seniors living in poverty, and the Commission should consider in its decision the customers that must make a choice between how well they can heat and cool their homes, and how much food they can buy.

The Commission accepts as credible, probative and entitled to substantial weight the testimony of public witnesses detailing how numerous North Carolina citizens struggle to make ends meet. The Commission also accepts as credible, probative and entitled to substantial weight the testimony of witness Johnson regarding economic conditions on a nationwide basis, indicating a high degree of economic stress since the 2008 recession. The Commission also accepts as credible, probative and entitled to substantial weight the testimony of witness Hevert indicating that economic conditions in North Carolina are not so dissimilar from economic conditions nationally as to provide any basis for an upward or downward adjustment in the Company's cost of capital.

As noted above, the Commission's duty under G.S. 62-133 is to set rates as low as reasonably possible without impairing the Company's ability to raise the capital needed to provide reliable electric service and recover its cost of providing service. The Commission is especially mindful of this duty in light of the evidence in this case concerning the impact of current economic conditions on customers.

The North Carolina Supreme Court has held that subjective judgment is a necessary part of setting the authorized ROE:

> Under N.C.G.S. § 62-133 the determination of what is a fair rate of return requires the exercise of subjective judgment. Utilities Commission v. Duke Power Co., 305 N.C. at 23, 287 S.E.2d at 799; see Utilities Comm. v. Telephone Co., 298 N.C. 162, 178, 257 S.E.2d 623, 634 (1979); Cf. J.C. Bonbright, A.L. Danielson, & D.R. Kamerschen, Principles of Public Utility Rates, 317 (1988) (describing the highly judgmental aspect of determining the cost of equity capital); C.F. Phillips, Jr., The Regulation of Public Utilities, 363-64 (1984) (noting the difficulty in estimating the cost of equity capital and recognizing that estimates vary significantly).

State ex rel. Utilities Com'n v. Public Staff, 323 NC 481, 490, 374 S.E.2d 361, 370 (1988). Indeed, of all the components of a utility's cost of service that must be determined in the ratemaking process the appropriate ROE is the one requiring the greatest degree of subjective judgment by the Commission. Setting an ROE for regulatory purposes is not simply a mathematical exercise, despite the quantitative models used by the expert witnesses. As explained in one prominent treatise:

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

Charles F. Phillips, Jr., <u>The Regulation of Public Utilities</u>, 3d ed. 1993, pp. 381-82. (Notes omitted.)

Thus, in determining the appropriate ROE to use in setting rates for DEP, the Commission must strike a balance that (1) avoids setting an ROE so low that it impairs the Company's ability to attract capital; (2) avoids setting an ROE any higher than needed to raise capital on reasonable terms; and (3) considers the impact of changing economic conditions on the utility's customers.

Chapter 62 in general, and G.S. 62-133 in particular, sets forth an elaborate formula the Commission must employ in establishing rates. The rate of return on cost of property element of the formula in G.S. 62-133(b)(4) is a significant but not independent one. Each element of the formula must be analyzed to determine the utility's cost of service and revenue requirement. The Commission must make innumerable subjective decisions with respect to each element in the formula in establishing the rates it approves in a general rate case. The Commission must approve accounting and proforma adjustments to comply with G.S. 62-133(b)(3). The Commission must approve depreciation rates pursuant to G.S. 62-133(b)(1). The decisions the Commission makes in each of these subjective areas have multiple and varied impacts on the decisions it makes elsewhere in establishing rates, such as its decision on the rate of return on equity.

In this case the Commission has required DEP to exclude from its rate base CWIP invested in the Sutton gas plant for the first year of the rate increase. This decision benefits ratepayers in this case by reducing the approved increase, thus making it easier for ratepayers to pay their electric bills in the current economic environment. However, this decision also impairs the quality of DEP's earnings. DEP accrues AFUDC, but these are non-cash earnings viewed by investors as earnings of inferior quality, thus subjecting DEP to greater risk. In establishing the 10.20% rate of return on equity, the Commission is mindful of its decision on Sutton CWIP.

The Commission has approved a phase-in of the rate increase that the evidence in this case justifies. This decision benefits ratepayers and lowers the rates they otherwise would pay in the current economic environment. However, the Company's equity investors forego the revenues to which they otherwise would be entitled during this time. The Commission most assuredly has taken this decision into account in establishing the 10.20% rate of return on equity.

The Commission has approved a capital structure of 53% equity, 47% debt, which is a capital structure with less equity than DEP's actual test year capital structure. The decision to use this proforma rate-making capital structure lowers the rate ratepayers pay and makes it easier for them to pay their bills in the current economic environment. However, it reduces debt coverage, increases leverage, and consequently increases risk to debt holders and lowers return to equity investors. The Commission takes this decision into account in approving a 10.20% rate of return on equity.

The Commission has approved distribution of $20 million for assistance to low-income customers and for training to improve access to jobs. This decision benefits ratepayers and particularly those with the least ability to pay in the current economic environment. At the same time this decision reduces by $20 million the fund that DEP has available for its future retirement of older plants and equipment. As a result, this is $20 million that DEP might have to replace out of DEP's future earnings, a risk borne by the Company's shareholders. The Commission takes this fact into account in approving the 10.20% rate of return on equity.

Under G.S. 62-133, rates are established on an historical test year as opposed to a future test year. This diminishes the ability for DEP to earn its authorized return, especially when it is in a plant constructing phase as is currently the case. This diminishes the rates ratepayers pay in the current economic environment. Nevertheless, it increases risk to investors and places DEP at a disadvantage when competing for capital with utilities where the rate-making formula is more favorable. The Commission takes this fact into consideration in establishing the 10.2% rate of return on equity.

The examples listed above are but a few of the instances where the Commission makes decisions in each general rate case (and has made such decisions in this case) that influence the Commission's determination on rate of return on equity and cost of service and the revenue requirement. The Commission always endeavors to comply with the North Carolina Supreme Court's requirements that it "fix rates as low as may be reasonably consistent" with U.S. Constitutional requirements irrespective of economic conditions in which ratepayers find themselves. While compliance with these requirements may have been implicit, and, the Commission reasonably assumed, self-evident as shown above, we make them explicit in this case to comply with the new Supreme Court requirements.

The Commission always places primary emphasis on consumers' ability to pay where economic conditions are difficult. By the same token, it places the same emphasis on consumers' ability to pay when economic conditions are favorable as when the unemployment rate is low. Always there are customers facing difficulty in paying utility bills. The Commission does not grant higher rates of return on equity when the general body of ratepayers is in a better position to pay than at other times, which would seem to be a logical but misguided corollary to the position the Attorney General advocates on this issue. Moreover, the Commission in establishing a rate of return on equity and other cost of service determinations is mindful that should it set the rate of return on equity too low, the impact on long term rates may be harmful to ratepayers. The utilities the Commission regulates compete in a market to raise capital. Financial analysts, rating agencies, and investors themselves scrutinize with great care the regulatory environment and decisions in which these utilities operate. The regulatory environment includes the utilities commissions, consumer advocates, the state legislature, the executive branch and the appellate courts. When regulatory risk is high, the cost of capital goes up. Should regulatory ratemaking decisions swing too far toward low consumer rates in a given case, the long term result may likely be higher rates in the future, irrespective of the now unknown economic conditions that will exist at such future time.

There is no clear numerical basis for quantifying the impact of economic conditions on customers in determining an appropriate ROE for setting rates in this case. This impact is essentially inherent in the ranges presented by the ROE 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. It is not measured by any of the traditional methods used by economists to determine the cost of equity in the marketplace. Nor can it be derived from public witness testimony. Thus, in accordance with the decision of the Supreme Court in State ex rel. Utilities Com'n v. Public Staff, the Commission must exercise its subjective judgment in balancing two competing ROE factors - the economic conditions facing the Company's customers and the Company's need to attract equity financing in order to continue providing safe and reliable service. Id. at 490, 374 S.E.2d at 370. Based on all of the evidence presented, the Commission has balanced those two factors using three categories of evidence, as follows.

The Commission gives significant weight to the testimony of witness Yates regarding the Company's need to raise capital at this time to finance the improvements needed for safe, adequate and reliable electric service. The Commission notes that no credible or substantial evidence was presented disputing the prudency, reasonableness or necessity of these improvements and their cost. The Commission must set the Company's ROE at a level that will enable the Company to access the equity capital markets and raise the capital needed to provide safe, adequate and reliable service.

As shown by the evidence, relatively small changes in the ROE have a substantial impact on a utility's base rates. Therefore, the Commission has carefully considered the changing economic conditions and their effects on DEP's customers in reaching its decision regarding DEP's approved ROE. As discussed above, the public witnesses in this case provided extensive testimony concerning the high unemployment, home foreclosures and other economic stress experienced by DEP's customers during the last several years. The Commission accepts as credible, probative and entitled to substantial weight the testimony of the public witnesses detailing how numerous North Carolina citizens struggle to make ends meet. The Commission also accepts as credible, probative and entitled to substantial weight the testimony of witness Johnson regarding economic conditions on a nationwide basis, indicating a high degree of economic stress since the 2008 recession. The Commission also accepts as credible, probative and entitled to substantial weight the testimony of witness Hevert indicating that economic conditions in North Carolina are not so dissimilar from economic conditions nationally as to provide any basis for an upward or downward adjustment in the Company's cost of capital.

Finally the Commission gives weight to the Stipulation and the benefits that it provides to DEP's customers, which the Commission is obliged to consider as an independent piece of evidence under the Supreme Court's holdings in CUCA I and CUCA II. As with all settlement agreements, each party to the Stipulation gained some benefits that it deemed important and gave some concessions for those benefits. Based on DEP's application and pre-filed testimony, it is apparent that the Stipulation ties the 10.20% ROE to substantial concessions the Company made to alleviate the impact of the rate increase on customers. In particular, the Company agreed to delay for one year its statutory right to recover the financing costs on the CWIP for its new Sutton CC. The result is revenues for the Company that are $31,258,000 lower in the first year of the rate increase. Additionally, the Company will convert $20 million of a regulatory liability to be used for the benefit of North Carolina retail customers by (a) local agencies and organizations for programs that provide assistance to low-income customers and (b) programs that provide training that improves worker access to jobs and increases the quality of the workforce. Absent the Stipulation, these benefits to customers would not exist.

Based on the changing economic conditions and their effects on DEP's customers, the Commission recognizes the financial difficulty that the increase in DEP's rates will create for some of DEP's customers, especially low-income customers. The Commission must weigh this impact against the benefits that DEP's customers derive from DEP's ability to provide safe, adequate and reliable electric service. Safe, adequate and reliable electric service is essential to the support of businesses, jobs, hospitals, government services and the maintenance of a healthy environment. For example, witness Yates testified about DEP's major investments in the replacement of older coal plants with new natural gas combined cycle facilities and the installation of emissions control equipment on the Company's more modern coal plants. These improvements are expensive, but they also improve the efficiency of DEP's generating facilities, lower the Company's operating costs and enhance the environment. These are significant benefits that are received by all of DEP's customers. The Commission concludes that the ROE approved by the Commission appropriately balances the benefits received by DEP's customers from DEP's provision of safe, adequate and reliable electric service in support of businesses, jobs, hospitals, government services and the maintenance of a healthy environment with the difficulties that some of DEP's customers will experience in paying DEP's increased rates.

3. Conclusion as to ROE.

In sum, the Commission finds and concludes, for purposes of this case and after thoroughly and independently reviewing all of the evidence that an ROE of 10.20% is just and reasonable based on the evidence concerning changing economic conditions as they affect DEP's customers. Moreover, the Commission concludes that witness Hevert's rebuttal DCF analysis, particularly as it relates to his findings concerning mean growth rates, is credible and deserving of great weight, and that witness Johnson's comparable earnings analysis provides independent corroboration for the results of that analysis and is also deserving of great weight, and that an ROE of 10.20% is fully supported by both of those analyses. The Commission finds and concludes, for the reasons set forth herein, that the ROE analysis of witness O'Donnell is to be afforded only very limited weight. A 10.20% ROE was also found by this Commission to be appropriate in the recently concluded DNCP Rate Case, and, in accordance with the analyses conducted by witnesses Chriss, Rosa and Hevert, is within the range of average ROEs for vertically integrated electric utilities allowed by other utilities commissions in recent years. Accordingly, the Commission's analysis of the evidence concerning changing economic conditions as they affect customers, the Stipulation, and the expert ROE evidence leads it to the conclusion that an ROE of 10.20% strikes a fair balance and will result in just and reasonable rates in light of all the evidence presented, including the effects of changing economic conditions on DEP's customers.

The Commission notes further that its approval of an ROE at the level of 10.20% – 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. Rather, as North Carolina law requires, setting the ROE at this level merely affords DEP 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.

Capital Structure

Duke Energy Progress originally proposed using a capital structure of 43.98% long-term debt, 0.62% preferred stock, and 55.39% common equity, which was the Company's actual regulatory capital structure as of the end of the test period. The Stipulation provides for a modified capital structure of 47% long-term debt and 53% equity.

Company witness De May testified that DEP's actual capital structure includes approximately 53% equity as of December 31, 2012, on a regulatory basis.[1] Witness De May explained that financial strength and the ability to attract capital, both debt and equity, on reasonable terms are vitally necessary for DEP to provide cost-effective, safe, environmentally

[1] Regulatory capital structure excludes short-term debt and losses on unregulated subsidiaries.

compliant, and reliable service to its customers. To assure reliable and cost effective service to its customers, fund infrastructure projects, and refinance maturing debt, he stated that DEP must be able to finance without interruption, regardless of market conditions. Witness De May noted that lack of access to capital can force interruption of capital projects to the long-term detriment of customers. He testified that although recent market conditions have improved, the financial crisis of 2008-2009 illustrates the importance of maintaining the financial strength, flexibility, and strong credit ratings of DEP which result in lower debt costs for its customers and assurance of access to capital, even in challenging market conditions. Further, he testified that the Company's strong balance sheet is an asset to customers as it helps the Company maintain access to capital on reasonable terms to deal with unforeseen events while still maintaining the safe, reliable, and environmentally compliant service that the Company's customers expect. He explained that one of the Company's primary objectives that supports financial strength and flexibility is maintaining at least 53% common equity for DEP on a regulatory capitalization basis.

Witness De May testified that the stipulated capital structure is within the range of Standard & Poor's (S&P's) and Moody's criteria for the Company's current credit ratings. He stated that Commission approval of the Stipulation would be viewed by rating agencies as constructive and equitable. Witness De May also testified that approval of the Stipulation would support the Company's ability to achieve its financial objectives.

Public Staff witness Johnson also testified in support of the stipulated capital structure of 53% equity and 47% long-term debt. Witness Johnson recommended that the Commission establish rates consistent with the Stipulation and testified that allowing DEP an opportunity to earn an overall rate of return of 7.55% is reasonable and consistent with the public interest.

In his pre-filed direct testimony, CUCA witness O'Donnell recommended that the Commission use a 50/50 debt/equity ratio, based upon the capital structure of the Company's parent company. However, he noted on cross examination that in light of CUCA's position regarding the Stipulation, the only parts of his pre-filed direct testimony that "would be applicable [in this proceeding] are rate design and Rider IER." (T, Vol. 3, p.162.)

In his rebuttal testimony, witness De May stated that it is inappropriate to use a parent capital structure in this case because DEP is a regulated utility operating company, not a parent-level holding company. He testified that a better way to assess the reasonableness of the Company's capital structure is to analyze several regulated utilities' capital structures over a period of time. Witness De May conducted an analysis of the capital structures of the companies included in witness O'Donnell's ROE proxy group over the eight quarters ending September 12, 2012. Witness De May testified that his analysis revealed an average equity ratio of 54%, and stated that this demonstrates that the 53% equity component in the Stipulation is reasonable and in line with other regulated utility companies.

At the hearing, counsel for the Attorney General questioned witness De May as to whether he believed that the current low cost of debt would offset the additional cost of equity that would be introduced if the Company added more leverage. Witness De May responded that it is not simply a question of cost, but that when additional leverage is introduced into the Company, there is additional risk, which in turn puts weight on the Company's credit ratings.

Further, witness De May stated that access to capital is just as important as cost of capital, and access is driven significantly by the Company's credit quality.

In his Brief, the Attorney General recommends that the Commission reject the 53% equity and 47% debt capital structure set forth in the Stipulation because it would increase the Company's revenue requirement by $17.1 million compared to a sufficiently conservative capital structure consisting of 50% equity and 50% debt, and nothing in the record supports the need for the higher equity ratio. According to the Attorney General, the Company offered no evidence as to why it requires a significantly higher equity ratio than that established in its last rate case, nor did it offer evidence as to why it requires a higher equity ratio than its parent company. The Attorney General states that based on the evidence the Commission should consider adopting a hypothetical capital structure consisting of a lower percentage of equity, such as 50%, which is reflective of the equity ratio of Duke Energy Corporation, the parent company of DEP. The Attorney General proffers that DEP customers should not be required to pay higher rates simply because the Company prefers to maintain a higher level of equity, and that a lower equity ratio would limit the size of the rate increase without causing negative market consequences to the Company.

The Commission concludes that DEP's actual capital structure at December 31, 2012 includes approximately 53% common equity. The Commission concludes that a capital structure of approximately 47% long-term debt and 53% common equity is appropriate based upon the evidence in this proceeding. The Commission reaches this conclusion in part by giving weight to the historical common equity of the Company, with an average common equity ratio of 54.6% for the eight quarters ending September 2012, and the 53.8% average actual common equity for the Company for the first quarter of 2007 through the third quarter of 2012, as shown on De May Rebuttal Exhibit 1. In addition, as noted above, Company witness De May testified that DEP is a regulated utility operating company, not a parent holding company, and that a better way to assess the reasonableness of the Company's actual capital structure is to analyze the capital structures of several regulated utilities over a period of time. When he did so, as demonstrated on De May Exhibit 2, his analysis revealed an average equity ratio for the group of approximately 54%.

The Attorney General did not provide any evidence on this issue. Contrary to the assertions of the Attorney General, the Commission concludes that the evidence presented by the Company supports the reasonableness of the Company's actual 53% equity ratio and provides a more reasonable basis of comparison than the Company's equity ratio at the time of its last general rate case in 1988, the equity ratio of one parent holding company, or a hypothetical capital structure. The Commission also gives significant weight to the testimony of witness De May that a strong equity component is a factor in determining the Company's credit rating. It would be counterproductive for DEP to lower its equity ratio and increase its amount of debt if that action results in a downgrading of the Company's credit rating and thereby causes an increase in its cost of debt. Further, the Commission gives significant weight to the testimony of witness Yates regarding the Company's need to raise capital at this time to finance the improvements needed for safe, adequate and reliable electric service. The Commission notes that no credible or substantial evidence was presented disputing the prudency, reasonableness or necessity of these improvements and their cost. The Commission concludes that a capital structure consisting of 47% debt and 53%

common equity will allow the Company access to capital markets and raise the capital needed to provide safe, adequate and reliable service.

The Commission has carefully considered the changing economic conditions and their effects on DEP's customers in reaching its decision regarding DEP's capital structure. As discussed in the previous section concerning ROE, which is incorporated herein, the public witnesses in this case provided extensive testimony concerning the high unemployment, home foreclosures and other economic stress experienced by DEP's customers during the last several years. The Commission accepts as credible, probative and entitled to substantial weight the testimony of the public witnesses detailing how numerous North Carolina citizens struggle to make ends meet. The Commission also accepts as credible, probative and entitled to substantial weight the testimony of witness Johnson regarding economic conditions on a nationwide basis, indicating a high degree of economic stress since the 2008 recession. Finally, the Commission gives weight to the Stipulation and the benefits that it provides to DEP's customers, including the two year phase-in of the rate increase, the one year delay in the Company's statutory right to recover the financing costs on the CWIP for its new Sutton CC, and the $20 million contribution to assistance for low-income ratepayers and job training programs.

Based on the changing economic conditions and their effects on DEP's customers, the Commission recognizes the financial difficulty that the increase in DEP's rates will create for some of DEP's customers, especially low-income customers. The Commission must weigh this impact against the benefits that DEP's customers derive from DEP's ability to provide safe, adequate and reliable electric service. Safe, adequate and reliable electric service is essential to the support of businesses, jobs, hospitals, government services and the maintenance of a healthy environment. For example, witness Yates testified about DEP's major investments in the replacement of older coal plants with new natural gas combined cycle facilities and the installation of emissions control equipment on the Company's more modern coal plants. These improvements are expensive, but they also improve the efficiency of DEP's generating facilities, lower the Company's operating costs and enhance the environment. These are significant benefits that are received by all of DEP's customers. The Commission concludes that the capital structure approved by the Commission appropriately balances the benefits received by DEP's customers from DEP's provision of safe, adequate and reliable electric service in support of businesses, jobs, hospitals, government services and the maintenance of a healthy environment with the difficulties that some of DEP's customers will experience in paying DEP's increased rates.

Based on all the evidence, the Commission finds and concludes that a capital structure of 47% long-term debt and 53% common equity is just and reasonable to all parties.

<u>Cost of Debt</u>

The Company proposed a long-term debt cost of 4.57%, which is its annualized cost of debt as of the end of the test period, with adjustments for post-test period debt issuances and retirements. The Stipulation also provides for a 4.57% cost of debt.

The Company’s cost of debt calculation is set forth on page 2 of Exhibit 4 to Company witness Bateman’s direct testimony. Witness Bateman explained that in May of 2012, the Company issued $500 million of debt at a rate of 4.1% and $500 million of debt at a rate of

2.8%, and in July of 2012, the Company retired $500 million of debt at a 6.5% rate. An adjustment was made to the end-of-test-period cost of debt to include the impact of these issuances and retirements. Witness Bateman explained that because the new debt issuances will become part of DEP's embedded cost of debt for the foreseeable future, it is appropriate to include the impacts of these issuances and retirements in this proceeding.

Public Staff witness Johnson supported an embedded cost of debt of 4.57%. He testified that 4.57% is a substantially lower debt rate than the rate approved by this Commission in the DNCP's Rate Order in Docket No. E-22, Sub 479. Witness Johnson also agreed that this debt rate properly reflects the impact of several downward adjustments, which flow through to customers the benefit of reductions in DEP's cost of debt that occurred after the end of the test period.

No intervenor offered any evidence to contradict the use of 4.57% as the cost of debt. The Commission therefore finds and concludes that the use of a debt cost of 4.57% is just and reasonable to all parties in light of all the evidence presented.

Revenue Increase

In the Application and initial direct testimony and exhibits, DEP provided evidence supporting a net increase of $359,232,000 (which included the net impacts associated with transferring the DSDR program into base rates and application of the Company's proposed Rider IER), or approximately 11% in its annual non-fuel revenues from its North Carolina retail electric operations. On January 18, 2013, the Company filed supplemental direct testimony and exhibits updating several cost of service adjustments.

Pursuant to the Stipulation, the Company and the Public Staff have agreed upon a two-step increase in DEP's annual electric sales revenue from its North Carolina retail electric operations, totaling $178,712,000.[1] The increase will be phased in over two years. In the first year, the Stipulation provides for an increase in rates of $147,384,000, or approximately 4.6%. In the second year, the Stipulation provides for an additional increase in rates of $31,328,000, or approximately 1%. The undisputed evidence before the Commission indicates the following amounts of test year pro forma operating revenues, operating revenue deductions, and original cost rate base (under present rates) to be used as the basis for setting rates in this proceeding: $3,224,444,000 of operating revenues, $2,822,979,000 of operating revenue deductions, and $6,701,450,000 of original cost rate base. Revised Hoard Exhibit 1 contains a verified and detailed breakdown of these amounts.

The Public Staff filed direct testimony on February 28, 2013, recommending and supporting the Stipulation adjustments, set forth in Revised Hoard Exhibit 1 and Revised

[1] This increase reflects the withdrawal of the request to move the DSDR program into base rates and is also net of any effect of the proposed IER Rider.

Settlement Agreement 1,[1] to the Company's requested revenue increase, as modified by the Company's supplemental filings. For example, Public Staff witness Hoard supported numerous adjustments, including adjustments to the Company's new depreciation rates, Wayne CC deferral, lobbying expenses, advertising expenses, and vegetation management expenses. Public Staff witness Hinton supported adjustments to the Company's customer growth and nuclear decommissioning funding requirements. Public Staff witness Ellis supported adjustments to the level of coal inventory, nuclear outage expenses, the level of materials and supplies for the Company's end of life nuclear reserves, and nuclear operation and maintenance expenses. Public Staff witness Maness supported adjustments to the Company's non-fuel variable O&M expenses and REPS expenses, among other things. The Public Staff's recommended adjustments supporting the Stipulation are summarized in Revised Hoard Exhibit 1, Schedule 1.

The Company filed testimony in support of the Stipulation on March 14, 2013, accepting some of the Stipulation adjustments recommended by the Public Staff and choosing not to contest others. In particular, Company witness Bateman testified that the Company agrees with the following adjustments, as listed on Schedule 1 of Hoard Exhibit 1: the adjustment to change the retention factor (Line 6); the adjustment to remove REPS expenses (Line 13); the adjustment to normalize nuclear refueling outage costs (Line 26); the adjustment to treatment of the gains on Harris land sales and emission allowances (Line 30); and the adjustment for the rounding difference (Line 37). As to the remaining Public Staff adjustments, witness Bateman testified that the Company decided, for purposes of this proceeding only, not to contest other issues—in whole or in part—because the Company felt it served the interest of its customers in this particular case. Witness Bateman explained that the Company's acceptance of these adjustments does not constitute agreement with the Public Staff's positions and should not be taken as indicative of positions the Company may take on similar topics in future proceedings.

Thus, the mechanism by which the Company and the Public Staff arrived at the agreed revenue requirement in the Stipulation was to take a common starting point (the Company's requested revenue requirement, as adjusted by its supplemental filings and testimony), and then agree upon a series of adjustments to that number, with the resulting sum totaling the stipulated revenue requirement. The adjustments start with reductions in the revenue requirement resulting from the change in equity ratio as agreed in the Stipulation (Line 4 of Revised Settlement Exhibit 1) and from the change in ROE (Line 5 of Revised Settlement Exhibit 1), and continue with additional adjustments captured in Lines 6 through 38 of Revised Settlement Exhibit 1 to arrive at the final agreed upon revenue requirement, which, the Stipulating Parties agree should allow the Company to provide safe, reliable, and cost-effective electric service to its customers.

However, it is evident from the testimony of the Public Staff and the Company that while both Stipulating Parties have agreed on the absolute amount of the revenue requirement, they have differing views on the particular adjustments that make up the requirement and take differing routes to arrive at that level of revenue. As Company witness Newton aptly put it, the

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[1] Revised Settlement Exhibit 1 and Revised Hoard Exhibit 1 were filed on March 14, 2013, and March 15, 2013, respectively, and reflect the reduction to the recommended increase in the base revenue requirement to $178,712,000 as a result of the removal of DSDR from base rates. Revised Settlement Exhibit 1 also incorporated four additional changes from the original Settlement Exhibit 1, none of which affected the recommended revenue requirement.

settlement embodied by the Stipulation "represents a negotiated compromise of a complex set of issues . . . [and] is the product of extensive give-and-take negotiations between the Company and the Public Staff [and therefore] . . . not surprisingly the settlement reflects some instances where [the parties] could agree to a fair overall revenue impact but not on the characterization of some of the adjustments." (T, Vol. 8, p. 114)

With respect to Line 37 of Revised Settlement Exhibit 1, on cross-examination, witness Bateman testified that the $42 million adjustment to post test year expenses represented the give and take of settlement and the compromise of the two parties. Witness Bateman contended that, from the Company's perspective, there are several adjustments that sum to approximately $37 million that, absent the settlement, DEP would not have agreed with. For example, she stated that the Public Staff's adjustments to the DOE settlement and vegetation management expenses would be captured in the $42 million in post test year expenses. Further, she explained that there were three additional items that provide value in the Stipulation and have a cost to the Company which would also be represented in the $42 million of post test year expenses. First, under the Stipulation, DEP agreed to lock in the jurisdictional revenue requirement using the 1CP allocation methodology in order for the stipulated revenue requirement to be unaffected by the Commission's decision regarding the appropriate allocation methodology for use in this proceeding. Witness Bateman explained that, absent the Stipulation, if the Commission were to decide that SWPA is the appropriate allocation methodology as recommended by the Public Staff in this proceeding, the Company's jurisdictional revenue requirement would increase by $20 million. However, she stated that under the Stipulation, the Company has agreed to forego that increase. She asserted that such agreement provides value to the customers but is a cost to the Company that is reflected in the context of the settlement.

Additionally, witness Bateman testified with respect to the Sutton CWIP that although the Company will continue to accrue AFUDC during the construction phase of the plant, DEP has agreed to forego recovery of the costs from the date when the plant goes into service (the middle of December 2013), until June 2014, when the full rate increase becomes effective. Witness Bateman testified that this provision in the Stipulation represents about $14 million that the Company has agreed to give up on a one-time basis and will never seek to recover at a later point in time. Witness Bateman explained that the third item that provides value to the customer at a cost to the Company relates to the agreed upon $20 million contribution to low-income and job recruitment programs. Witness Bateman contended that DEP is taking on slightly more risk by agreeing to reduce a regulatory liability and that there is a cost, albeit small, associated with that risk. Witness Bateman summarized that the $42 million in post test year expenses makes agreement with those three items, as well as acceptance of the other Public Staff adjustments, acceptable in the context of the settlement from the Company's perspective. She commented that if Public Staff witness Hoard were asked to characterize the components of the $42 million in post test year expenses, he might have a different answer than the Company.

In response to follow-up questions by CUCA's attorney regarding her explanation of the $42 million in post test year expenses and the estimated $20 million difference in jurisdictional revenue requirement related to the use of the SWPA methodology versus the 1CP methodology contained therein, witness Bateman was cautioned by her attorney that "we're getting very close to confidential settlement discussions, and I would just like to point that out and object to going too far down that path." Chairman Finley ruled that CUCA's attorney should "…try to avoid talking about confidential settlement discussions." CUCA's attorney responded to witness Bateman, "I don't want you to say anything that was said in confidence. I'm just asking you what the fallout of that is." (T, Vol. 2, p. 133)

On cross-examination, witness Hoard testified that in the Public Staff's view approximately $20 million of the $42 million in post test year expenses is composed of the rate base items to move from 1CP to SWPA, as well as the expense items that move from one method to the other. Further, witness Hoard testified that the $42 million in post test year expenses also includes other items related to the give and take of negotiation.

In addition, Public Staff witness McLawhorn testified that the $42 million in post test year expenses is not a meaningless number but rather a number that means two different things to the Stipulating Parties. Witness McLawhorn testified that the 44 line item exhibit entitled Revised Settlement Exhibit 1, which supports the agreements contained in Paragraph 2.B. and 2.C. of the Stipulation, was informed by the substantial number of responses by DEP to questions contained in Public Staff data requests and by the Public Staff's numerous on-site document reviews of other auditing processes and the NCUC Form E-1 items.

In its Brief, NC WARN observed that the Stipulating Parties had made significant concessions to reach the settlement, most notably an additional $38,471,000[1] as "post test year expenses." NC WARN commented that DEP and the Public Staff disagreed about what items were contained in the post test year expenses, referred to at the evidentiary hearing as the "sweetener." According to NC WARN, witness Bateman testified that "this number represents the give and take of settlement and the compromise of the two parties" and that DEP would not have settled without it. NC WARN observed that witness Hoard also discussed the post test year expenses. NC WARN commented that both parties agreed that regardless of what particular items were included in the sweetener, the amount was essential in achieving the settlement. NC WARN argued that negotiated rates between parties do not alleviate the Commission's responsibility in establishing that such rates are fair and reasonable and that the weight and sufficiency of all of the testimony and evidence needs to be determined. NC WARN contended that in this proceeding the fairness and reasonableness of the undesignated post test year expenses should be closely scrutinized.

In regard to the Sutton CWIP costs, in its Brief the Commercial Group stated that if the Commission does not adopt the Stipulation, the Commission should exclude the Sutton CWIP costs from rate base because: (1) the Sutton CC natural gas plant would not be in service during the test year; (2) the Sutton plant is not the type plant envisioned as baseload plant by Senate Bill 3; and (3) the plant may only operate as a baseload plant for a short period of time.

The Commission agrees with NC WARN that whether the amount of DEP's revenue increase is set by a negotiated settlement or by contested evidence, the end result must be just and reasonable rates. Further, in reaching that end result the Commission must consider and weigh all of the evidence, including the testimony, exhibits and the Stipulation. The evidence in this case

[1] The Stipulated Parties amended the Stipulation on March 14, 2013, and adjusted the amount of post test year expenses from $38,471,000 to $42,267,000.

began with DEP's Application, Form E-1and pre-filed testimony. Those filings contain substantial evidence supporting the line item costs included in DEP's original proposed revenue increase of $359,232,000. Because the Public Staff and DEP reached a settlement agreement, the Public Staff filed testimony in support of the Stipulation and discussed the accounting and ratemaking adjustments to which the Stipulating Parties agreed. The Public Staff did not specifically address or challenge the details of the various other line item costs included in DEP’s proposed revenue increase. In his pre-filed direct testimony, CUCA witness O’Donnell challenged DEP’s accelerated depreciation on its unscrubbed coal plants, pension costs and executive pay. However, witness O’Donnell noted on cross-examination that in light of CUCA’s position regarding the Stipulation the only parts of his pre-filed direct testimony that “would be applicable [in this proceeding] are rate design and Rider IER.” (T, Vol. 3, p.162.) Witness O’Donnell’s testimony on these cost items having been withdrawn and, consequently, having not been subject to cross-examination, the Commission gives his testimony no weight. No other intervenor presented substantial or credible evidence challenging the details of DEP’s line item costs.

The Stipulation includes the Public Staff’s adjustments presented on Revised Settlement Exhibit 1, with the most widely discussed adjustment being the post test year expenses of $42 million. As explained by the Public Staff and DEP, this adjustment does not clearly correspond with specific line items presented in Hoard Revised Exhibit 1.[1] In assessing the weight to be given to the Stipulation, the Commission recognizes that the parties to a general rate case may reach agreement on an ultimate settlement of the total amount of a revenue increase while adhering to positions on certain issues that, on their face, could appear inconsistent with the ultimate settlement. For example, the Public Staff might believe that DEP's depreciation expense should be $10 million less, while DEP refuses to accept any adjustment to its depreciation expense. On the other hand, DEP might be willing to accept a $12 million reduction in its REPS expenses, while the Public Staff was expecting to achieve only a $5 million reduction in that line item. In the context of the ultimate settlement this type of give-and-take is the means by which the parties reach the stipulated revenue increase. Thus, the negotiated revenue requirement will likely be somewhere between the litigation positions that the Stipulating Parties would have pursued absent the settlement.

It is not the role of the Commission to look behind the Stipulation into the details of how and why DEP agreed to certain provisions that advanced the Public Staff's interests and the Public Staff agreed to other provisions that advanced DEP's interests. Indeed, the rules of evidence prohibit the introduction of evidence of statements made during settlement discussions. <u>See</u> G.S. 8C-1, Rule 408. Further, it would be counterproductive for the Commission to attempt to evaluate the individual provisions of the Stipulation in a vacuum or to attempt to pull the details apart and approve certain provisions while refusing to accept others. An individual provision of the Stipulation, standing alone, might well be unreasonable. However, the Stipulation specifies in Paragraph No. 11 that it is a comprehensive package and is binding on the Stipulating Parties only if accepted in its entirety by the Commission.

[1] Revised Hoard Exhibit 1 contains numerous schedules which support both the rate base and net operating income components with respect to the agreed-upon revenue increase presented on Revised Settlement Exhibit 1.

The Commission recognizes that the Stipulating Parties may reach agreement during confidential settlement negotiations on the overall revenue requirement while providing differing testimony on particular adjustments on which reasonable persons could disagree. In fact, as pointed out during the evidentiary hearing, the Stipulating Parties may not be able to show how they arrived line-by-line at the stipulated revenue increase without discussing confidential settlement negotiations. Further, the Commission is of the opinion that the Stipulating Parties need not show how they arrived line-by-line at the stipulated revenue increase, especially where, as here, the stipulated revenue increase is based, in part, on a global, yet non-specific resolution of many individual revenue requirement items in dispute between the Stipulating Parties. See Order Granting General Rate Increase and Approving Amended Stipulation, Docket E-7, Sub 909, at 36 (Dec. 7, 2009). This is particularly so in a situation, like the present case, in which no intervenor presented any substantial evidence challenging the justness or reasonableness of any of the individual adjustments set forth in Lines 6 through 39 of Revised Settlement Exhibit 1. Intervenors who challenge a utility's prima facie evidence concerning the reasonableness of its costs have a burden of production, even though the utility ultimately bears the burden of persuasion. See State ex rel. Utils. Comm'n v. Intervenor Residents, 305 N.C. 62, 76, 286 S.E. 2d 770, 784 (1982) ("[t]he burden of going forward with evidence of reasonableness and justness arises only when the Commission requires it or affirmative evidence is offered by a party to the proceeding that challenges the reasonableness of expenses allocated to it by an affiliated company…"); State ex rel. Utils. Comm'n v. Conservation Council, 312 N.C. 59, 64, 320 S.E. 2d 679, 684 (1984) ("Costs are presumed to be reasonable unless challenged."); Order Approving Fuel Charge Adjustment, Docket No. E-7, Sub 780 (June 15, 2005) (finding expenses reasonable where utility witness testified that expenses were reasonable and this testimony was not contradicted or challenged by any other witness). Further, in State ex rel. Utilities Comm'n v. Carolina Utility Customers Association, 348 N.C. 452, 466, 500 S.E. 2d 693, 707 (1998), the Supreme Court noted the value of settlement agreements, stating that the Court "recognizes the crucial role that informal disposition plays in quickly and efficiently resolving many contested proceedings and encourages all parties to seek such resolution through open, honest and equitable negotiation." This is the same case in which the Court held that the Commission is required to consider a non-unanimous stipulation in addition to any other evidence and relevant facts presented to the Commission.

Moreover, a Stipulation can achieve benefits for customers that the Commission could not order on its own. In particular, the Stipulation provides that DEP will implement a decrement rider for one year, beginning on the effective date of the rates approved in this proceeding, to delay inclusion of Sutton CWIP in rate base, resulting in a $31,328,000 reduction in the revenue increase. Further, the Stipulation provides for the rate increase to be phased in over two years. These measures could not be ordered by the Commission absent agreement by the Company.

The Commission gives significant weight to the evidence presented in DEP's pre-filed testimony and exhibits with regard to DEP's line item costs. Further, the Commission gives significant weight to the testimony in support of the Stipulation, and the lack of any credible evidence refuting the reasonableness of the line item adjustments made by the Stipulating Parties. Finally, the Commission gives significant weight to the Stipulation as the reasonable product of the give-and-take of settlement negotiations. Based on the evidence, the Commission finds and concludes that the $178,712,000 revenue increase provided in the Stipulation is just and reasonable to all the parties and should be approved.

ELECTRIC – RATE INCREASE

Based on the conclusions set forth thus far in this Order, the Commission has reviewed the Stipulation's provisions for an annual non-fuel revenue increase of $178,712,000, to be phased in over two years, and finds and concludes that this increase in the level of base rates to be paid by DEP's North Carolina retail customers, resulting in an overall rate of return of 7.55% on jurisdictional rate base and a return on common equity of 10.20% using a capital structure of 47% long-term debt and 53% common equity, is just and reasonable to all parties in light of all the evidence presented.

The Commission further finds and concludes that the following amounts of operating revenues, operating revenue deductions, and original cost rate base (under present rates) are appropriate and reasonable for purposes of setting rates in this proceeding: $3,224,444,000 of operating revenues, $2,822,979,000 of operating revenue deductions, and $6,701,450,000 of original cost rate base.

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, Progress Energy Carolinas is authorized to increase its annual level of revenues by $178,712,000 based upon the adjusted test year level of operations.

SCHEDULE I
DUKE ENERGY PROGRESS, INC.
North Carolina Retail Operations
Docket No. E-2, Sub 1023
STATEMENT OF OPERATING INCOME
For the Twelve Months Ended March 31, 2012
(000's Omitted)

Item	Present Rates	Approved Increase	Approved Rates
Electric operating revenue	$ 3,224,444	$ 178,712	$ 3,403,156
Operating expenses:			
Operation & maintenance	2,087,849	662	2,088,511
Depreciation	397,647	0	397,647
Amortization	(6,504)	0	(6,504)
Other taxes	176,653	5,740	182,393
Income taxes	164,447	67,555	232,002
Investment tax credits	(3,793)	0	(3,793)
Total operating expenses	2,816,299	73,957	2,890,256
Return before interest on deposits	408,145	104,755	512,900
Interest on customer deposits	(6,680)	0	(6,680)
Net operating income for return	$ 401,465	$ 104,755	$ 506,220

SCHEDULE II

DUKE ENERGY PROGRESS, INC.
North Carolina Retail Operations
Docket No. E-2, Sub 1023
STATEMENT OF RATE BASE AND RATE OF RETURN
For the Twelve Months Ended March 31, 2012
(000's Omitted)

Item	Amount
Electric plant in service	$13,456,625
Accumulated depreciation and amortization	(6,556,654)
Net electric plant in service	6,899,971
Nuclear fuel inventory	269,879
Accumulated deferred income taxes	(1,461,257)
Regulatory assets and liabilities	563,726
Operating reserves	(360,611)
Materials and supplies	459,743
Cash working capital	56,398
Construction work in progress	273,601
Total original cost rate base	$ 6,701,450
Rates of Return:	
Present rates	5.99%
Approved rates	7.55%

SCHEDULE III

DUKE ENERGY PROGRESS, INC.
North Carolina Retail Operations
Docket No. E-2, Sub 1023
STATEMENT OF CAPITALIZATION AND RELATED COSTS
For the Twelve Months Ended March 31, 2012
(000's Omitted)

Item	Capital-ization Ratio	Original Cost Rate Base	Embedded Cost	Net Operating Income
		Present Rates – Original Cost Rate Base		
Long-term debt	47.00%	$ 3,149,682	4.57%	$ 143,940
Common equity	53.00%	3,551,768	7.25%	257,525
Total	100.00%	$ 6,701,450		$ 401,465
		Approved Rates – Original Cost Rate Base		
Long-term debt	47.00%	$3,149,682	4.57%	$ 143,940
Common equity	53.00%	3,551,768	10.20%	362,280
Total	100.00%	$ 6,701,450		$ 506,220

EVIDENCE IN SUPPORT OF FINDING OF FACT AND CONCLUSION NO. 23

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

Company witness Newton testified that pursuant to the Stipulation, the inclusion of CWIP in rate base stemming from the construction of Sutton CC will be delayed for one year as a means of phasing in the impact of the overall rate increase on customers. Company witness Bateman explained that Senate Bill 3 allows utilities to include CWIP for baseload units in rate base in the context of a general rate case. Although the Company originally planned Sutton CC to be dispatched as an intermediate plant, it is now expected to operate as a baseload plant, as indicated by the Company's 2011 and 2012 Integrated Resource Plans (IRPs). However, as witness Bateman clarified, even though the Company is permitted to include CWIP for Sutton CC in base rates in this proceeding, it has agreed in the Stipulation to delay collection of the costs of Sutton CWIP until after the plant is in service in order to mitigate the impact of the rate increase on customers. Witness Bateman explained that while the Company will not collect the costs of Sutton CWIP in base rates during the first year rates go into effect, the Company will continue to accrue AFUDC until the plant goes into service.

Public Staff witnesses Hoard and Johnson also testified in support of the decrement rider under which inclusion of CWIP for Sutton CC will be delayed for one year. Witness Hoard cited the phase-in of the rate increase through the use of this rider as one of the most important benefits provided to ratepayers by the Stipulation. Witness Johnson testified that although the Company was allowed under State law to earn a return on CWIP for Sutton CC, it had agreed to delay collection for one year to phase-in the rate increase. No intervenor offered any evidence in opposition to the Stipulating Parties' proposal to phase-in the rate increase through delaying the inclusion of Sutton CWIP in rate base for one year.

The Commission agrees that the one-year Sutton CWIP decrement rider appropriately balances the Company's need for a rate increase with mitigation of the impact of this rate increase on customers during difficult economic circumstances. The Commission finds and concludes that the decrement rider proposed by the Stipulating Parties is just and reasonable to all parties in light of all the evidence presented.

EVIDENCE IN SUPPORT OF FINDINGS OF FACT AND CONCLUSIONS NOS. 24-26

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

Company witness Barkley provided testimony in support of the proposed base fuel and fuel-related cost factors in the Company's Application. These factors included the Experience Modification Factors (EMFs) as proposed by the Company in its 2012 fuel and fuel-related cost adjustment proceeding in Docket No. E-2, Sub 1018 (Sub 1018). As stated in witness Barkley's testimony in that proceeding, these proposed factors are based upon the Company's forecasted fuel and fuel-related costs for the period December 1, 2012, through November 30, 2013. Witness

Barkley explained that DEP proposed to adjust the factors used in this proceeding, as necessary, to conform to the factors approved by the Commission in Sub 1018. He testified that the Company's North Carolina retail adjusted fuel and fuel-related expense for the test period ending March 31, 2012, was $1,104,066,204. Witness Barkley explained that he calculated this amount using the proposed base fuel and fuel-related cost factors proposed in Sub 1018 and the North Carolina retail test period megawatt-hour sales as adjusted for weather and customer growth.

Witness Barkley also testified about the additional fuel cost to be collected from North Carolina retail customers due to the line loss differential. He explained that the Company's North Carolina retail line loss percentage exceeds its system-wide line loss percentage. The line loss differential is the difference in these percentages multiplied by the proposed total system fuel expense, $5,866,906 in this proceeding. Witness Barkley testified that DEP proposes to begin recovering this cost through its adjustment clause for fuel and fuel-related costs simultaneously with the effective date of the rates approved in this proceeding. He further explained that monthly deferred fuel calculations and the prospective treatment of the line loss differential would be subject to review in the Company's future fuel and fuel-related cost adjustment proceedings. Witness Bateman did not include the costs associated with the retail line loss differential in the Company's proposed base rates in this proceeding.

Lastly, witness Barkley testified about the Company's proposed allocation of fuel costs between rate classes in future fuel and fuel-related cost recovery proceedings. He explained that there are nine categories of "costs of fuel and fuel-related costs" that are eligible for recovery through the fuel clause under G.S. 62-133.2(a1). Witness Barkley explained that DEP proposes to allocate subdivisions (1) through (4) and (7) through (9) on the basis of forecasted energy. G.S. 62-133.2(a2)(2) requires the allocation of subdivisions (5) and (6) to be based upon peak demand until different treatment is approved by the Commission in a general rate case. The Company proposed to continue the allocation by peak demand for subdivisions (5) and (6) in the same manner the Commission has approved in the Company's fuel and fuel-related cost adjustment proceedings since 2008.

The Stipulating Parties agreed to the following fuel and fuel-related cost factors, incorporating those factors approved by the Commission on November 16, 2012, in Sub 1018:

	Residential	SGS	MGS	LGS	Lighting
Non-Capacity Purchased Power effective December 1, 2012, in Sub 1018	0.246	0.241	0.24	0.232	0.236
Cogeneration Capacity and Renewables effective December 1, 2012, in Sub 1018	0.222	0.213	0.174	0.125	0.000
All other Fuel Costs effective December 1, 2012, in Sub 1018	2.562	2.566	2.521	2.612	3.456
Total Base Fuel	3.030	3.020	2.935	2.969	3.692
EMF effective December 1, 2012, in Sub 1018	0.033	0.066	0.036	-0.046	-0.214
Total approved Fuel and Fuel-Related Cost Factor	3.063	3.086	2.971	2.923	3.478

Public Staff witness Maness testified that the Public Staff accepted the Company's proposal regarding recovery of the fuel line loss differential. He testified that under the Company's proposed approach, the Company will recover the North Carolina retail fuel line loss differential, but the actual cash effect on ratepayers will be deferred until December 2013. The Stipulation provides that beginning with the effective date of the new rates the North Carolina retail fuel line loss differential shall be recovered as part of the fuel and fuel-related cost factor, and not as part of the non-fuel component of base rates. The Company will include the line loss differential in the prospective component of its fuel and fuel-related cost factor in the Company's annual fuel charge proceedings.

Witness Maness recommended several changes to the Company's proposed allocation of fuel-related costs in future fuel and fuel-related cost recovery proceedings. For the purposes of determining the prospective and EMF components of the factors set in fuel and fuel-related cost proceedings, the Public Staff recommended the following allocation methods for the costs described in G.S. 62-133.2(a1):

> (1) The costs described in subdivision (4) shall be allocated on an energy only basis, using as appropriate the same annual or monthly, forecasted or actual energy allocation factors and methodology currently used in the annual fuel proceedings for costs falling under subdivisions (1), (2), (3), and (7) ("all other fuel costs");
>
> (2) The costs described in subdivision (5) shall be allocated using the production plant allocation factor as updated in the annual cost of service filings, using the cost of service methodology approved in the Company's most recent general rate case; and
>
> (3) The costs described in subdivision (6), which have both capacity-related and energy-related components, shall be allocated using, for the energy-related costs, the same energy allocation factors as used for subdivision (4) costs above, and, for the capacity-related costs, the same production plant allocation factor as used for subdivision (5) costs.

(T, Vol. 3, p. 27)

The Stipulation incorporates the allocations recommended by witness Maness, provided that these allocations shall not be a precedent for and may be contested in future general rate case proceedings.

Public Staff witness Maness testified that during the course of the Public Staff's investigation it became evident that the Company had included revenues and expenses associated with the fuel EMF in the cost of service. Because the fuel EMF is a true-up adjustment that is handled entirely in fuel clause proceedings, and because it is not part of the base fuel factor, he recommended elimination of these revenues and expenses from the cost of service. His recommendation did not affect the increase recommended pursuant to the Stipulation. However, witness Maness testified that it ensures that fuel-related revenues and expenses presented in this proceeding relate only to the proposed base fuel factor, not additional amounts. This adjustment was included in the exhibits of Public Staff witness Hoard that form the basis of the amounts accepted as reasonable by the Commission in Finding of Fact and Conclusion No. 10.

No intervenor contested these provisions of the Stipulation or the testimony of Public Staff witness Maness regarding fuel revenue and expenses for purposes of this proceeding. The Commission finds and concludes, based on the Stipulation and the undisputed exhibits of witness Maness, that the North Carolina retail base fuel expense for this proceeding is $1,099,039,000, and that the following base fuel and fuel-related cost factors are just and reasonable to all parties in light of all the evidence presented, for purposes of this proceeding (amounts are cents per kWh, excluding gross receipts tax and regulatory fee): 3.030 for residential customers; 3.020 for SGS customers; 2.935 for MGS customers; 2.969 for LGS customers; and 3.692 for Lighting customers.[1] The Commission also finds and concludes that the retail fuel line loss differential provision in Paragraph 3.B. of the Stipulation and the allocation of fuel and fuel-related costs as set forth in Paragraph 3.C. of the Stipulation and recommended by witness Maness are just and reasonable to all parties in light of all the evidence presented.

EVIDENCE IN SUPPORT OF FINDING OF FACT AND CONCLUSION NO. 27

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

Company witness O’Sheasy provided testimony regarding the Company’s proposed changes to rate design. Witness O’Sheasy’s direct testimony focused on DEP’s major proposed rate design initiatives, including: (1) a new TOU rate design for residential customers; (2) a new TOU rate design for small non-residential customers; (3) new tariffs for customers desiring either firm or non-firm standby service; and (4) a new optional tariff for customers agreeing to curtail 1,000 kW or more at the Company’s request. The new TOU tariffs will be effective December 1, 2013, to allow adequate time to promote and implement the new rate designs. The elimination of Schedule R-TOUE will then commence as these customers are migrated to the new residential R-TOU design, unless they request to be served under standard Residential Service Schedule RES. Witness O’Sheasy explained that the Company’s proposed rates must be set to achieve the necessary total revenue requirement and reflect the cost of service within the Company’s five major rate classes: Residential, SGS, MGS, LGS, and various Outdoor Lighting schedules. He explained that because the Company’s rates have not been modified since its last general rate case in 1988, some rates may have drifted further from unit costs than others. In order to move rate schedules and riders closer to a more efficient cost basis, it is important to consider the impact upon customers and, therefore, to employ the principle of “gradualism.” Witness O’Sheasy explained that the Company used this principle not only to minimize the potential for rate shock on participants, but also to minimize rate migration concerns, while still trying to move rate classes toward a more equitable pricing structure.

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[1] The fuel EMF is not part of the base rates approved in a general rate case.

In Paragraph 5 of the Stipulation, the Stipulating Parties agreed to implement the rate design proposed by Company witness O'Sheasy, subject to the following modifications:

(1) The Company shall increase its Basic Customer Charge (BCC) for Schedule RES to $11.50 per month and increase its BCC for Schedules R-TOUD, R-TOUE, and R-TOU to $14.60 per month.

(2) The Company shall close Schedule R-TOUD to new customers, except for those who will be served under Rider NM, Net Metering.

(3) The Company will not adjust the on-peak hours in the medium and large general service TOU rate schedules, MGS-TOU and LGS-TOU at this time. DEP shall complete a study of its TOU hours for all customer classes to ensure that TOU hours appropriately reflect the cost to serve these customers and the actual conditions of DEP's utility system. The results of this study will be provided in the Company's next general rate case or within two years from the date of order approving the rate schedules submitted pursuant to paragraph 2.F. of the Stipulation (Approval Order), whichever comes first.

(4) DEP shall implement its proposed minimum charge for distribution facilities for rate schedules SGS-TOU, CH-TOUE, GS-TES, APH-TES, CSE, and CSG. Within 60 days of the Commission's Approval Order, the Company shall evaluate the service of each customer impacted by the minimum bill provisions for each rate schedule and determine whether the customer would be better served under another rate schedule. The Company shall make a proactive effort to ensure that any customer impacted by the minimum bill provisions is afforded the opportunity to migrate to the most advantageous rate schedule for electric service.

(5) DEP shall implement proposed Riders SS and NFS to provide supplementary and standby service. DEP shall also cancel its existing Riders 66 and SSSW, with all existing customers being migrated to Rider SS or NFS as appropriate, and Rider 57 shall remain closed to new customers. The standby delivery charge for Rider NFS shall be $0.00220 per kWh for service at transmission level, and $0.00501 per kWh for service at distribution level, as adjusted to reflect the LGS rate class unit cost derived from the authorized cost of service study that reflects approved rates.

(6) DEP shall cancel Riders 58 and CL, and transfer existing participants in these riders to its proposed Rider LLC. DEP shall set the rate credit included in Rider LLC based on the marginal avoided capacity and energy rates supported by the Company's IRP of $5.90 per kW using the Public Staff's methodology.

Witness O'Sheasy also testified that the rate design issues addressed in the Stipulation present a reasonable approach to implementing the Company's proposed rate design. He recognized that although the residential BCC has been reduced below the Company's requested rate, it moves towards the cost level supported by the Company's unit cost analysis and therefore balances cost recovery and customer impact concerns.

In his direct testimony, Public Staff witness Floyd explained the stipulated rate design provisions as set forth above. He testified that in spreading the impact of the combined base revenue changes among the customer classes, the following principles should be followed: (1) the combined base revenue increase for any customer class should be limited to no more than two percentage points greater than the overall jurisdictional increase; (2) a plus or minus 10% "band of reasonableness" should be used, such that, to the extent possible, the class rates of return after the rate changes stay within this band of reasonableness; and (3) subsidization of customer classes by other classes should be minimized.

Several intervenors provided testimony on various rate design issues in this proceeding, as discussed below. Having considered the testimony and exhibits of all of the witnesses and the entire record in this proceeding, the Commission makes its findings and conclusions on each of these issues as set forth below.

Constant Load Provision of Schedule SGS-TOU

In his pre-filed direct testimony, Time Warner witness Coughlan proposed the following two changes to the pricing structure of the constant load provision of DEP's SGS-TOU schedule: (1) that the energy charge (cost per kWh) under the constant load provision of the SGS-TOU rate should be set at the level which equates to the overall cost per kWh for a 100% load factor customer under the SGS-TOU rate (which under the proposed rates would be $0.06926/kWh); and (2) that the BCC for customers receiving service under the constant load provision of Schedule SGS-TOU should be reduced from $17.00 per month to $4.10 per month.

In regard to cable television (CATV) power supply equipment, witness Coughlan testified that cable television companies require thousands of small amplifier devices along the length of the cable system. These devices have a 100% load factor, drawing the same power requirement at all times. CATV power supplies are served by the Company under the constant load provision of the SGS-TOU rate. Witness Coughlan asserted that these devices would be billed unfairly under DEP's proposed constant load provision rate because this rate fails to take into account the fact that these devices cost less to serve on a cost per kWh basis. Witness Coughlan explained that because CATV power supplies have a constant 100% load factor at all times, these customers are currently billed at a fixed cost per kWh that is calculated by averaging the hourly cost during on-peak and off-peak times. He proposed that the energy rate for CATV power supplies continue to be determined using this methodology.

Witness Coughlan also proposed a reduced BCC for CATV power supplies. He asserted that the facilities and customer-related costs to serve CATV power supplies are much lower than those required to serve other customers. He cited several reasons why CATV power supplies cost less to serve, including reduced cost associated with service length, right of way procurement, clearing and maintenance, trenching, service conductor size, transformation, metering, account setup, and ongoing billing. In his pre-filed direct testimony, witness Coughlan argued that in terms of facilities to serve a customer, the most similar customer type to CATV power supplies is traffic signals, which he argued are almost identical in operating and load characteristics to

CATV power supplies. He noted that Duke Energy Carolinas serves traffic signals for a BCC of $4.22 per month. Accordingly, witness Coughlin proposed that DEP reduce its BCC for CATV power supplies to $4.10 per month. However, in the summary of his direct testimony presented at the evidentiary hearing, witness Coughlan changed this recommendation of $4.10 per month to a recommendation that the BCC for DEP’s residential customers of $11.50 per month also apply to CATV power supplies.

Company witness O’Sheasy provided testimony describing how the rates under the constant load provision were established. He explained that even though CATV amplifiers have no ability to shift usage away from on-peak hours, their owners determined that they would benefit from TOU pricing and therefore requested service under Schedule SGS-TOU. Witness O’Sheasy noted that the Company recognized that on-peak and off-peak usage could be accurately estimated for these customers without the installation of more expensive TOU metering. Therefore, the Company introduced the constant load pricing provision of Schedule SGS-TOU to render the same bill as if the standard SGS-TOU prices using a TOU meter had been used, but without incurring the cost of the more expensive TOU meter.

Witness O’Sheasy explained that under the proposed rates, the BCC for customers receiving service under the constant load provision of SGS-TOU will now be below what other SGS-TOU customers pay in recognition of the lower TOU meter costs under the constant load provision. He noted that the single energy rate is set in a manner to achieve the same overall percentage change in revenue for customers served under the constant load provision as other SGS-TOU customers on average. Witness O’Sheasy testified that this approach results in a lower bill for customers served under the constant load provision than would be realized under a normal SGS-TOU billing, assuming a TOU meter was installed.

Witness O’Sheasy testified that witness Coughlan incorrectly picks a customer charge from one schedule - first Duke Energy Carolinas’ traffic signal customer charge, and subsequently DEP’s residential customer charge - and simply combines it with an energy charge from another schedule (SGS-TOU), without considering what the combined effects will be compared to the overall targeted revenue change for the schedule. He explained that for a proposed constant load application, witness Coughlan has calculated an energy rate using the same basis as DEP’s current rate design for Schedule SGS-TOU, but then fails to recognize that the Company is also significantly reducing the constant load customer charge below the proposed SGS-TOU BCC. Witness O’Sheasy asserted that one cannot pick a customer charge from one schedule and simply combine it with an energy charge from another schedule without considering what the combined effect will be compared to the target for the schedule. In other words, as witness O’Sheasy testified at the evidentiary hearing, “Rate design is not like eating a buffet lunch where you can pick and choose what you want to eat and … end up paying the same price.” (T, Vol. 7, p. 117)

Witness O’Sheasy testified further that the MGS class is currently subsidizing the SGS-TOU customers. Under current rates, DEP realizes a return of only 4.14% for Schedule SGS-TOU, much less than the 9.71% return realized by all other MGS class tariffs; therefore, Schedule SGS-TOU is recommended to receive a larger increase than other MGS class tariffs, according to witness O’Sheasy. He testified that under witness Coughlan’s proposal, a customer charge of $4.10 and an energy charge of $0.06926 per kWh would result in a monthly bill of

$38.04 for the average CATV amplifier using 490 kWh per month, or 27% less than such a customer currently pays. This would result in a significant rate decrease, which, according to witness O'Sheasy, is inappropriate and would further exacerbate the subsidization of the SGS-TOU schedule. He testified that by requesting a customer charge of only $17 rather than the $23.12 justified by the unit cost for the MGS rate class, DEP has already given these customers a significant benefit over their actual cost of service for customer-related costs. Witness O'Sheasy noted that it is particularly important to set the customer charge at the level supported by the unit cost for lower usage customers, such as these CATV accounts, to avoid subsidization by other customers within the rate class.

In its Brief, Time Warner submits that DEP's proposed design of SGS-TOU fails to remedy the subsidization that constant load devices have paid for 20 years and will continue to provide by paying a BCC that is not cost based. Time Warner asserts that SGS-TOU-CLR customers would pay an increase in their combined demand and energy charges that is more than 300% of the increase being asked of all other customers under the same rate schedule, and that this creates an unduly discriminatory rate differential that has no cost basis, in violation of G.S. 62-140 and State policy outlined in G.S. 62-2(a)(4). Further, Time Warner submits that the cost components of a unit based BCC should be set independently of the demand and energy charges of each rate. Thus, the Commission should direct DEP to establish the kWh charge of the SGS-TOUE-CLR and SGS-TOU-CLR to be in parity with the ultimate energy and demand cost components of Schedule SGS-TOU.

In its assessment of the evidence on this issue, the Commission gives substantial weight to three points made by witness O'Sheasy: (1) there is no evidence supporting Time Warner's proposal to use DEP's residential BCC as the customer charge for SGS-TOU; (2) DEP's proposed rate design lowers the BCC for customers receiving service under the constant load provision of SGS-TOU to below what other SGS-TOU customers pay in recognition of the lower TOU meter costs under the constant load provision; and (3) the energy rate for constant load customers is set to achieve the same overall percentage change in revenue for constant load customers as other SGS-TOU customers on average. Therefore, for the purpose of the current proceeding, the Commission finds and concludes that the pricing structure established for customers receiving service under the constant load provision of SGS-TOU is just and reasonable. However, the Commission also finds and concludes that the unique load factor characteristics of CATV power supply equipment and related cost of service issues, as discussed by witness Coughlan, merit a full review by the Company to determine whether a more appropriate rate provision should be established and implemented for CATV power supply equipment as part of DEP's next general rate case proceeding.

Schedule SGS-TOU

In his testimony on behalf of LCFWSA, witness Coughlan recommended that the current 1,000 kW limit be removed from Schedule SGS-TOU to allow customers with larger loads to be served. He explained that when the Company implemented the 1,000 kW maximum demand limit in the mid-1980s, customers that were being served under SGS-TOU with a higher demand were grandfathered in and could continue service under that rate until the customer had a change in corporate ownership or added load to such an extent that the Company was required to upgrade its electrical facilities. Witness Coughlan asserted that the current 1,000 kW limit is unfair because it makes it difficult for new customers that are the same size and in the same line of business to compete with older customers that are still able to receive lower rates on schedule SGS-TOU, despite exceeding the demand limit.

Witness O'Sheasy disagreed with witness Coughlan's recommendation to remove the demand limit on SGS-TOU. He explained that due to an unintended impact of the rate design of SGS-TOU approved in the Company's last general rate case, class customers selecting service under SGS-TOU realize a significant bill savings without changing their consumption patterns. Further, the number of customers being served under Schedule SGS-TOU has increased from 35% in 1988 to 60% of the MGS class today. As a result, and as described above, DEP realizes a 4.14% return under current SGS-TOU, much less than the 9.71% return realized from the remaining MGS tariffs. Witness O'Sheasy concluded that offering a tariff with lower rates of return to more customers by removing the 1,000 kW limit on SGS-TOU would only exacerbate this situation.

Witness O'Sheasy also provided testimony as to how the Company has proposed to correct the situation in this rate case. He asserted that it is inappropriate to correct the pricing deficiency in one step, but he believes that moving toward rate parity is appropriate. Thus, DEP has recommended that rates for Schedule SGS-TOU be increased by approximately 15% more than other MGS class tariffs (*e.g.*, if Schedule MGS increases by 10%, then SGS-TOU would increase by 11.5%). According to witness O'Sheasy, while this approach fails to achieve rate parity, it attempts to help resolve the problem without resulting in significant rate increases for any particular SGS-TOU customer.

In weighing the evidence on this issue, the Commission gives substantial weight to three points made by witness O'Sheasy: (1) there has been a large influx of customers choosing SGS-TOU without having to change their consumption patterns, which has resulted in DEP realizing only a 4.14% return under SGS-TOU; (2) DEP's proposed rate design begins moving SGS-TOU to rate parity by increasing the schedule rates approximately 15% more than other MGS class tariffs; and (3) eliminating the 1,000 kW maximum demand limitation would cause more MGS customers to move to SGS-TOU, thus hampering the Company's efforts to achieve rate parity. Therefore, the Commission finds and concludes that removing the 1,000 kW limit from Schedule SGS-TOU would undermine the Company's appropriate attempts to gradually close the gap between SGS-TOU rates and other MGS tariffs, and, therefore, the proposal to do so should not be accepted.

TOU Pricing Structures

Witness Coughlan and Kroger witness Higgins provided testimony recommending structural changes to the Company's non-residential TOU rate designs. Witness Coughlan recommended revising LGS and LGS-TOU rates to lower the load factor at which LGS-TOU becomes advantageous. Witness Higgins recommended revising SGS-TOU rates to raise the demand charge. Witness O'Sheasy testified that neither of these rate design proposals is appropriate and they both would potentially create significant rate increases for certain customers served under these schedules.

In NCLM's Brief and Partial Proposed Order, it stated that the usage characteristics of water and sewer treatment facilities are sufficiently unique that a special rate class should be developed specifically for this group of customers. Since DEP's last rate case, water and sewer treatment operations have become increasingly automated and technologically advanced. Such advancement allows certain operations—such as water pumping, as one example—to take place during off-peak hours. The shifting of operations to off-peak hours lowers the cost incurred by DEP to serve these facilities, and such savings should be reflected in rates to these customers. Given the capabilities of these facilities to shift load and to allow DEP to peak shave, and their unique characteristic of providing essential services to all citizens, the development of a specific rate class for these sewer facilities could be addressed in the study that the Company has committed to undertake. NCLM requests that the Commission order DEP to study the usage characteristics of water and sewer treatment facilities, consider their special circumstances, and develop a specific rate class for these facilities, in the context of the TOU study.

Witness O'Sheasy provided testimony regarding the Company's plan to evaluate its non-residential TOU pricing structures applicable to the general service class to improve their effectiveness. He pointed out that the Stipulation includes a requirement for DEP to evaluate TOU pricing structures and to provide a report to the Commission within two years. According to witness O'Sheasy, this will allow deployment of more sophisticated interval metering for many of the MGS class customers. He explained that while lower rates may be appropriate for HLF customers based upon their cost of service, the Company hopes that a TOU rate design can be offered at a future date that would also be effective in encouraging load shifting away from DEP's peak hours on a cost-effective basis. However, witness O'Sheasy concluded that it is premature to alter the current pricing structure significantly before the Company's evaluation is complete.

Witness Higgins contended that the Company's proposed rate design for SGS-TOU significantly understates the demand charges and overstates the energy charges. He proposed that SGS-TOU demand rates be increased to better reflect the demand-related unit cost of the MGS class.

Witness O'Sheasy disagreed with this proposal, noting that the Company is not proposing to base its rate designs solely upon embedded unit cost of demand, and that such a proposal would not be advisable. Instead, DEP's recommended design involves consideration of both embedded and marginal cost. The Company considered the embedded unit cost in its rate design, but does not recommend that the results be accepted without judgment. Witness O'Sheasy explained that marginal cost was also considered in setting the overall rate levels of all tariffs, as well as seasonal and time-of-day price relationships. Consideration of marginal cost is important in any rate design to ensure that the customer is provided efficient price signals regarding its electrical consumption decisions, according to witness O'Sheasy. He explained that the current SGS-TOU demand rates exceed marginal cost. Consequently, significant increases in these rates, bringing them close to embedded unit cost, were deemed to be inappropriate. Instead, a consideration of both embedded and marginal cost was used. DEP therefore increased the SGS-TOU demand rates by 50% of the energy rate in an attempt to better recognize both the rate class embedded unit cost and marginal cost.

Witness O'Sheasy testified that the SGS-TOU rates proposed by the Company are equitable in their impact on customers, in that all SGS-TOU customers receive a 9 to 10% increase. He explained that witness Higgins' proposed rate design would increase customer bills by 7 to 12%, greatly benefiting HLF customers, such as Kroger, to the detriment of lower load factor customers.

Kroger contends in its Brief that DEP's proposed design of SGS-TOU significantly understates the demand charge while significantly overstating the energy charges. Kroger maintains that this over-recovery of energy costs and under-recovery of demand costs is particularly inequitable to HLF customers because energy charges for SGS-TOU are already significantly above test period energy costs for SGS-TOU. Therefore, Kroger recommends that the Commission accept the BCC proposed by DEP, and allow the recovery of the remaining revenue increase for SGS-TOU through an increase in the demand charge, leaving energy charges unchanged. According to Kroger, this rate design will result in a more reasonable rate impact based on customer load factor, since the primary driver of the rate increase is capacity/demand-related costs. On the other hand, if demand costs are under-recovered in SGS-TOU, the costs will be recovered in energy charges. If this happens, then HLF customers will be required to pay the demand-related costs of lower-load-factor customers, which amounts to an inequitable cross-subsidy.

As demonstrated by this evidence concerning TOU pricing structures, as well as that previously discussed regarding constant load provisions and eligibility requirements for SGS-TOU, there appears to be some general inconsistency and imbalance in DEP's TOU rate schedules. That is not surprising because more sophisticated metering and TOU rate schedules have developed largely in the last twenty years and DEP has not had a general rate case during that time. Therefore, the Commission gives substantial weight to witness O'Sheasy's testimony that the SGS-TOU rates proposed by the Company are equitable in their impact on customers, and that the Company's proposal to conduct a TOU study will result in a more organized approach to a comprehensive resolution of the issues for all customer classes, rather than the piecemeal approach proposed by witnesses Coughlan and Higgins. Thus, based on the Company's commitment under the Stipulation to evaluate TOU pricing structures and provide a report to the Commission within two years, the Commission finds and concludes that it is premature to order the Company to alter its current non-residential TOU rate designs until this evaluation is complete. Accordingly, the Commission declines to accept the changes to the Company's non-residential TOU rate designs recommended by witnesses Coughlan and Higgins. In addition, the Commission finds persuasive the position of NCLM that the usage characteristics of water and sewer treatment facilities are sufficiently unique that a special rate class should be developed specifically for this group of customers. Therefore, the Commission also directs the Company to include in its study an examination of the specific issues related to water and sewer treatment facilities raised by NCLM.

R-TOU

In its Brief, NCSEA states its support for DEP's goal of a 5 to 10% participation by residential customers in R-TOU. NCSEA contends that to achieve this goal R-TOU must be effectively marketed. NCSEA discusses testimony by DEP from 2006 stating that DEP had approximately 27,000 residential customers utilizing its TOU rate, and testimony in the present docket that the number is still approximately only 26,000. Given this lack of increase in the last several years, NCSEA submits that the Commission should require DEP to file a report in two years so that the Commission can monitor DEP's marketing effort. NCSEA cites G.S. 62-155(c) and G. S. 62-36 in support of its position, as well as previous statements by the Commission encouraging the utilities to inform new customers about the TOU rate option and to investigate opportunities to better educate their customers.

The Commission agrees with NCSEA that DEP should inform residential customers of the availability and benefits of the R-TOU tariff. However, the Commission is not persuaded that it should require DEP to establish a marketing program for R-TOU and to file reports concerning its marketing program. Pursuant to the Stipulation, DEP agrees to complete a study of the adoption of TOU rates by all customer classes and report the results of that study at the earliest of the Company's next general rate case or within two years from the date of the Order in this docket. The Commission will add to this requirement that the report shall include the details of all efforts made by DEP to inform customers about the availability of TOU rates and to encourage its customers' use of such rates. With this additional requirement, the Commission finds and concludes that the report required by the Stipulation is adequate and reasonable.

Light Emitting Diode Service

NCLM witness Howe testified about DEP's Light Emitting Diode (LED) street lighting and traffic signal services. He noted that DEP provides two options for LED street lighting: (1) the Company purchases and installs the LED lights, and the customer pays one monthly price, or (2) the customer owns the LED fixtures and pays the Company to install, operate, and maintain them. Witness Howe asserted that because the charge for the utility-owned option is higher than either the customer-owned option or conventional lighting, there is no cost-effective option for municipalities that cannot afford to purchase their own LED fixtures. He explained that North Carolina cities like Raleigh could realize large cost savings through LED lighting, and he proposed that DEP change the utility-owned charge to an amount closer to the cost municipalities would incur to own and maintain their own street lights. Furthermore, witness Howe proposed that because of emerging metrology technology for street lights, where a customer pays for the fixture and maintenance and only pays the utility for the cost of electricity consumed, DEP should allow municipalities to mount fixtures on existing Company poles at no cost. Witness Howe also recommended that DEP's rate schedules for traffic signals, including current TSS-19 and proposed TSS-24, differentiate between LED and conventional technology so that municipalities can realize cost savings from LED signals without having to invest in individual meters at each intersection.

Witness O'Sheasy testified that the Company's LED lighting rates are competitive with other light sources for customers desiring this lighting technology. He noted that the Company's current approach to LED pricing was approved by the Commission in Docket No. E-2, Sub 969, and allows billing rates to be adjusted downward as soon as LED fixture prices decline. He stated that current prices for LED fixtures are higher than those of other high intensity discharge (HID) fixtures, resulting in LED rates that are more expensive than comparable HID lighting. However, according to witness O'Sheasy, the Company's approach was beneficial because it allowed "early adopters" to receive LED lighting service immediately, while also allowing DEP to lower the total monthly rate quickly in the future as manufacturers' prices decline. Witness O'Sheasy explained that DEP is currently in final negotiations with lighting manufacturers and expects to lower its LED rates substantially in the near future. He testified that the monthly rate applicable to the LED 75 and LED 105 fixtures will be below the comparable HID monthly rate once the new purchase contracts are completed.

In NCLM's Brief, it asserts that there is sufficient data based on the number of metered LED traffic signals that have been and are now in use in the State to obtain LED usage data that will facilitate statistically significant analysis of the data for the purpose of studying the power usage of LED traffic signals. Further, cost of individual meters at each intersection is an unnecessary cost that municipalities should not have to pay. The energy saving and lower maintenance benefits of LED lighting should not be discouraged by the unnecessary additional cost of a traffic signal meter. Therefore, a non-metered rate for LED traffic signals should be developed and implemented by DEP.

NCLM also contends that DEP's cost to serve traffic signals is considerably less than the typical SGS customer Therefore, the customer charge under traffic signal schedules should be less than that for other SGS service.

With regard to LED street lighting, NCLM contends that based on the energy saving benefits of LED street lighting the public interest is served by policies that promote, or at least do not discourage, such lighting. Therefore, NCLM requests that the Commission direct DEP to study the costs incurred to serve LED street lighting in order to ensure that the those costs are accurately reflected in the rates paid by DEP's customers for such service.

Witness O'Sheasy also responded to witness Howe's recommendation to differentiate between LED and conventional technology for the Company's traffic signal service (TSS). Witness O'Sheasy explained that this request has been considered previously, and after reviewing Schedule TSS, the Company determined that it would be impossible to predict monthly consumption accurately when LED lighting is used. This conclusion led the Company to offer a new Traffic Signal Service Schedule TFS with metered service in 2009 (Docket No. E-2, Sub 955), to allow customers to benefit from lower energy consumption when using LED lighting.

In assessing the evidence on this issue, the Commission gives substantial weight to four points made by witness O'Sheasy: (1) the Company's LED lighting rates are competitive with other light sources; (2) the Company's LED lighting approach was approved by the Commission in Docket No. E-2, Sub 969; (3) it allows billing rates to be adjusted downward as soon as LED fixture prices decline; and (4) DEP is in final negotiations with lighting manufacturers and expects to lower its LED rates substantially in the near future. The Commission finds and concludes that DEP's current approach to rates for LED lighting for street lights and traffic signals is just and reasonable to all parties based on the evidence presented, and that the changes proposed by witness Howe should, therefore, not be accepted.

Electronic Data Interchange

NCLM witness Howe also requested that DEP consider using electronic data interchange (EDI) to transmit account data to customers so that the Company can provide customers with meter-specific data. He stated that using EDI would enhance municipalities' ability to evaluate and manage consumption and reduce the Company's and municipalities' administrative costs associated with managing multiple metered operations.

Company witness O'Sheasy responded to this request in his rebuttal testimony, stating that the Company has an ongoing process in place to convert customers requesting consolidated billing service to EDI. Witness O'Sheasy explained that the Company has been working for several months with the City of Raleigh to convert the city's billing to EDI. He stated that DEP has made EDI available to all customers who have the technical capabilities for receiving and interpreting bill data electronically sent through an industry-accepted Value Added Network.

The Commission finds and concludes that the Company's current practices with respect to EDI service for managing electronic billing are reasonable and appropriate.

Demand Response Automation Rider

DEP's Demand Response Automation (DRA) rider is available to non-residential customers that receive electric service with a contract demand of 200 kW or greater under rate schedules MGS, SGS-TOU, LGS, or LGS-TOU. Participating customers receive compensation for curtailing at least 75 kW during summer peak periods, up to ten times per year. The DRA rider is one of the Company's DSM/EE programs; therefore, customers that participate in the DRA rider are required to opt-in to paying charges associated with the Company's DSM/EE rider for ten years. NCLM witness Howe and LCFWSA witness Coughlan both recommended that Rider DRA be revised to allow participation without requiring payment of the DSM/EE rider.

According to NCLM witness Howe, most municipal facilities that would be eligible for service under Rider DRA are also eligible to opt out of payment of the Company's DSM/EE rider pursuant to G.S. 62-133.9(f). Witness Howe testified that under Rider DRA, it is possible for the DSM/EE charges to exceed the compensation received for curtailment. This creates a financial disincentive for municipalities to participate in the rider. He stated that none of Raleigh's facilities participate in Rider DRA for this reason, and that NCLM views this as a lost opportunity for both municipalities and utilities.

Similarly, witness Coughlan recommended that DEP eliminate the requirement that customers receiving service under the DRA rider pay the charges associated with the DSM/EE rider. He argued that because the Company realizes savings from customers' curtailment under Rider DRA, and these customers are also required to pay DSM/EE charges, DEP receives double compensation. Furthermore, according to witness Coughlan, the long-term costs of the DSM/EE rider can easily exceed the payments received under the DRA rider, resulting in many customers paying higher rates while also having to curtail load. He argued that eliminating the DSM/EE charge requirement for the DRA rider will improve pricing flexibility for customers that have the ability to shift load, and it will also reduce the overall rates for customers in the long term as the need for peak generating units is reduced.

In its Brief, NCLM contends that municipalities and public authorities should be eligible to receive service under Rider DRA even if they opt out of DEP's DSM/EE programs. According to NCLM, DRA-1A is unlike other DSM/EE programs and should be reclassified and removed from DEP's DSM/EE programs, with its revenues and expenses included in base rates. This would benefit DEP through increased peak-shaving and would incentivize municipal and public authority customers to shift load away from peak time.

Similarly, LCFWSA in its Brief contends that Rider DRA is often not a viable option for industrial customers and other large customers using over one million kWh a year that are eligible to opt out of DEP's DSM/EE Rider. The DSM/EE Rider compensates DEP for revenue losses and additional costs incurred when a customer participates in a DSM/EE program. On the other hand, DEP is compensated by DRA Rider participants by DEP's savings when it avoids purchasing expensive peak power on the wholesale market. Requiring a Rider DRA customer to pay additional compensation to DEP under the DSM/EE Rider results in double compensation to DEP.

Company witness O'Sheasy disagreed with the recommendation of witnesses Howe and Coughlan to eliminate the DSM/EE opt-in requirement for customers receiving service under the DRA rider. He explained that the Company introduced Rider DRA to emphasize DSM in response to Senate Bill 3, and the costs associated with the program are recovered in the DSM/EE rider. Senate Bill 3 provides that certain participants may opt out of paying the DSM/EE rate if they implement their own efficiency programs and do not participate in any new utility-sponsored DSM or EE programs, such as Rider DRA. Witness O'Sheasy explained that allowing customers to participate in a new utility-sponsored program, such as Rider DRA, without requiring them to pay for the cost of the DRA program via the DSM/EE rate would be inappropriate because it is inconsistent with the law and unfair to other customers.

In the Commission's Order Approving DSM/EE Rider and Requiring Filing of Proposed Customer Notice, issued on November 27, 2012, in Docket No. E-2, Sub 1019, the Commission ordered the Company to continue its efforts to develop and market a portfolio of DSM/EE programs attractive to commercial and industrial customers, including those who have opted out of participation. The DRA Rider appears to be exactly the type of DSM/EE program that may be attractive to commercial and industrial customers who have opted out of participation in the DSM/EE Rider.

The Commission is not persuaded by the testimony of witnesses Howe and Coughlan that there are significant benefits to be gained by removing Rider DRA from DEP's portfolio of DSM/EE programs. The DRA Rider is part of a balanced portfolio of DSM/EE programs carefully designed by DEP and reviewed and approved by the Commission. It would be counterproductive to pull programs out of the DSM/EE group on a piecemeal basis without sufficient evidence as to how that might affect the acceptance by customers of the remaining portfolio of DSM/EE programs and DEP's cost recovery under its DSM/EE rider. In addition, it would be inconsistent with the opt-out provision of Senate Bill 3 and with the Commission's rules.

Therefore, the Commission finds and concludes that the Company's requirement that customers receiving service under the DRA rider continue to pay the charges associated with the Company's DSM/EE rider is just and reasonable in light of all of the evidence presented.

Large Load Curtailable Rider LLC

Witness O'Sheasy testified that the Company's proposed Large Load Curtailable Rider LLC is available to customers with curtailable demands of 1,000 kW or greater and provides customers with credits to their electric bills for agreeing to curtail load when requested by DEP. Curtailment periods are for a maximum of eight hours per day, with a minimum of 30 minutes prior notice, and cannot exceed 400 hours annually. He explained that under Rider LLC, the Company will offer Level 1 and Level 2 curtailment options. During a Level 1 curtailment option, the customer may elect to continue to operate; however, an increased kWh rate applies. According to witness O'Sheasy, this option would apply when generation is available in the wholesale market during the peak period, but only at a high cost. During a Level 2 curtailment, system resources are constrained and generation is not readily available from the wholesale market.

Witness O'Sheasy explained that the rider provides for a fixed charge based upon the marginal cost of capacity that applies if a customer fails to reduce its load during a Level 2 curtailment event. The rider also provides for automatically increasing the firm demand and potential removal from the rider if, in subsequent curtailment periods, the participant again fails to reduce usage to or below its firm demand. Witness O'Sheasy testified that the intent of the charge for failure to comply is to allow the Company to recover the annual credit received by a customer that fails to deliver the agreed upon curtailable response. In addition, system planning relies upon this curtailable load, and therefore it is appropriate to impose a penalty on a non-compliant customer.

LCFWSA witness Coughlan recommended replacing the fixed charge in Rider LLC with the same type of penalty provision as in the DRA rider, and he also proposed that the minimum amount of curtailed load be reduced from 1,000 KW to 200 kW. He contended that the penalty provision and minimum load requirement in the proposed LLC rider unreasonably limit customer participation. Witness Coughlan asserted that under the Company's proposed penalty provision, customers risk having to pay higher electric bills if they sign up for Rider LLC and then cannot curtail when requested. Under the DRA rider, instead of incurring a fee for failure to curtail, customers forfeit future bill credits that they otherwise would have received. Witness Coughlan proposed that this type of penalty should be adopted for Rider LLC and that customers who fail to curtail to at least 90% of the requested load reduction should lose six months of future bill credits.

In its Brief, LCFWSA argues that the penalties for noncompliance charged under Rider LLC should not exceed the previously realized or future potential benefits of the program to the customer. It also notes that the language of the Rider should be revised to clarify the certification requirements for persons who conduct the required energy audits.

Witness O'Sheasy explained why compliance with the load reduction requirement under Rider LLC is important to DEP. The Company's IRP reflects non-firm load resources and uses them to reduce its generation resource addition requirements, to the benefit of its customers. Witness O'Sheasy testified that the noncompliance charge under Rider LLC is significant because a customer's failure to perform can lead to loss of service to customers during system peak conditions, a situation the Company strives to avoid.

Witness O'Sheasy testified that the Rider LLC noncompliance charge was selected because it approximates the return of the annual credit received by a customer that meets its contractual requirement. He explained that a more moderate non-compliance charge could lead to customers ignoring a curtailment request based upon economic decisions involving manufacturing or other requirements, with potentially dire consequences for DEP customers. Witness O'Sheasy suggested that customers with concerns over their ability to comply with their curtailable commitments should pursue service under Rider DRA, where the noncompliance charge removes future credits rather than seeking recovery of past discounts.

In response to witness Coughlan's recommendation that Rider LLC be opened to customers with curtailable loads as low as 200 kW, witness O'Sheasy testified that the 1,000-kW limit was selected because larger customers more clearly recognize the critical nature of their five-year commitment to curtail load. Since Rider DRA is readily available to general service customers with demands as low as 200 kW, provided they can provide at least 75 kW of curtailable load, witness O'Sheasy contended that it is inappropriate to expand Rider LLC for curtailable loads below 1,000 kW.

In assessing the evidence concerning DEP's Rider LLC, the Commission gives substantial weight to witness O'Sheasy's testimony that the non-compliance charge under Rider LLC is appropriate because the Company's system is planned in reliance upon this curtailable load. In addition, the Commission gives substantial weight to his testimony that the amount of the Rider LLC noncompliance charge approximates the return of the annual credit received by a customer that meets its contractual requirement under the rider. This is a balanced approach that gives Rider LLC customers the incentive to comply with their curtailment commitments, thus providing the Company with the reasonable expectation that load curtailment resources will be available to respond to changing system load conditions as needed. Further, the Commission gives weight to witness O'Sheasy's testimony that the 1,000-kW limit for Rider LLC was selected because larger customers more clearly recognize the critical nature of their five-year commitment to curtail load, and that Rider DRA is readily available to general service customers with demands as low as 200 kW. Therefore, the Commission finds and concludes that the non-compliance charge under Rider LLC is appropriate and that it would not be appropriate to expand Rider LLC to customers with curtailable loads below 1,000 kW.

Peak Time Pricing

In his testimony on behalf of LCFWSA, witness Coughlan requested that DEP be directed to study, develop, and propose a variable day pricing schedule and a critical peak pricing tariff for commercial and industrial customers by March 1, 2014.

In its Brief, LCFWSA states that DEP's present rates provide very few options and very limited pricing flexibility for commercial and industrial customers to shift their loads from on-peak to off-peak hours. It notes that Dominion Virginia Power and DNCP have a variety of rates that send customers daily price signals that allow those customers to curtail usage when system demand is high, including a variable day pricing rate called Schedule 10 and a critical peak pricing rate called Dynamic Pricing. LCFWSA submits that variable day pricing rates and/or a critical peak pricing rate would benefit DEP, its customers and the State. Therefore, it recommends that as DEP studies time of use hours for all classes, as proposed in the Stipulation, it would be appropriate to use the data to develop a variable day pricing rate and/or a critical peak pricing rate.

In response to witness Coughlan's recommendation, witness O'Sheasy testified that the Company supports demand response programs and is open to introducing new options, but is reluctant to offer new programs without a thorough review of its current demand response portfolio to assess how any new offerings would provide value not already being provided by current programs. Witness O'Sheasy then described the Company's current demand response and non-firm service options that encourage shifting of load to off-peak hours, including time-of-use pricing and numerous interruptible and curtailable programs, such as Riders LLC and DRA. He explained that these various programs have different expectations regarding the number of hours customers are expected to shift usage in order for the customer to gain an economic advantage, enable different technologies to help ensure the customer complies with the non-firm requirement, and have different approaches with regard to the financial consequence of non-compliance.

The Commission is not persuaded that DEP should be required at this time to offer additional load shifting rates. The Commission gives substantial weight to witness O'Sheasy's testimony that the Company currently offers a variety of demand response and non-firm service options that encourage shifting of load to off-peak hours, including time-of-use pricing and numerous interruptible and curtailable programs, such as Riders LLC and DRA. DEP currently has a balanced portfolio of DSM/EE programs carefully designed by DEP and reviewed and approved by the Commission. It would be more productive for the Company to thoroughly review its current demand response portfolio to assess how any new programs might compliment the Company's existing offerings. Further, given the Company's willingness to consider the introduction of new cost-effective demand-side management programs, the Commission does not at this time find good cause to require the Company to specifically develop and implement a variable pricing or critical peak rate as recommended by witness Coughlan.

Rider SS

Originally, the Company recommended that Rider No. 7, Rider No. 66, Rider SSSW, and existing Rider SS be terminated, with any existing participants being migrated to a new Supplementary and Firm Standby Service Rider SS. As reflected in the Amendment to the Stipulation filed on March 19, 2013, the Company later agreed to continue service under Rider No. 7.

In his direct testimony, Company witness O'Sheasy explained that the Company's new Rider SS will be available in conjunction with any of the Company's general service tariffs and will require the customer to contract for supplementary and standby service demand. Witness O'Sheasy explained that the Company has proposed billing under Rider SS, which reflects that standby service needs vary based upon the operating characteristics of the customer's generation. Thus, the new Rider SS includes charges based on the customer's Standby Service Contract Demand, which the Company proposes to define on the basis of the planning capacity factor of the customer's generation. As noted in the testimony of Commercial Group witness Chriss, the Standby Service Contract Demand for a customer's generation with a planning capacity factor of less than 60% will be set based on the nameplate kW capacity of the generation. For generation with a planning capacity factor of greater than 60%, the Standby Service Contract Demand is proposed to be the maximum increased demand the Company is requested to serve when the customer's generation is not operating.

The proposed new Rider SS also includes a monthly Generation Reservation Charge of $0.98 per kW of standby service for both customers above and below a 60% planning capacity factor. Witness O'Sheasy explained that in order to provide for standby service, the Company must acquire generation resources 15% in excess of its own predicted load requirement. Thus, the reservation charge is calculated by applying this 15% generation planning reserve margin to the Company's marginal generation cost calculated pursuant to the methodology approved in the most recent avoided cost proceeding, Docket No. E-100, Sub 127. The Generation Reservation Charge is then applied to the participant's contract kW of standby service. In witness O'Sheasy's view, this is a reasonable method for establishing the charge for standby requirements in excess of the supplementary service requirement.

Company witness O'Sheasy also proposed several revisions to Rider NFS to: (1) remove the experimental status of the rider; (2) clarify that the rider is only available to customers with generation having a planning capacity factor of 60% or greater; (3) require all customers with parallel generation to be served on a standby rider; and (4) include a new standby service delivery charge that is dependent on whether the customer receives service through transmission or distribution facilities. He explained that the use of the planning capacity factor of 60% or greater was intended to ensure that the customer's generation was both available and capable of operating during non-firm periods. Witness O'Sheasy also testified that the Company wanted all customers with parallel generation to be served under a standby service rider (firm or non-firm) to allow the Company to adequately identify the location of the generation on the distribution system. He further indicated that customers with small amounts of generation could contract for "0 kW" standby service to avoid charges for standby service, with usage being billed at normal tariff rates. Witness O'Sheasy testified that the new standby delivery charge was based on the Company's study of the unit cost to provide compensation for the delivery infrastructure necessary to render standby service during times when the Company's system is near peak conditions.

Public Staff witness Floyd testified in support of witness O'Sheasy's position that when a customer installs self-generation and requires standby service for times when the self-generation is not operating, the Company must maintain sufficient generation facilities to meet the customer's demand, and the cost of those facilities may be taken into account in setting the rates for standby service.

Commercial Group witness Chriss made several recommendations regarding the Company's proposed new Rider SS. His concerns focused around setting the Standby Service Contract Demand and the pricing of the Generation Reservation Charge. First, witness Chriss recommended that the Company define the Standby Service Contract Demand for all types of generation in the same manner. He contended that DEP's proposed setting of Standby Service Contract Demand can potentially overcharge a customer with a planning capacity factor below 60% and, therefore, is inequitable in its application. Witness Chriss also testified that the TOU periods exacerbate this problem. In his opinion, this aspect of the Company's proposed new Rider SS would add significant cost to solar and wind generation, and therefore it presents a barrier to customer installations of on-site solar or wind generation.

In rebuttal, Company witness O'Sheasy testified that renewable generation customers with planning capacity factors below 60% are different from those with planning capacity factors greater than 60%. They are dependent upon the availability of their energy resource, and they have little ability to influence the hours when their generation is operative. He explained that unlike cogeneration and base load generation resources with capacity planning factors greater than 60%, when renewable generation with a capacity factor less than 60% fails, the load required of the utility often instantly increases by the full output of the failed self-generator. The Company is responsible for constructing the facilities necessary to meet this sudden dramatic increase in demand. Witness O'Sheasy testified that Rider SS allows the customer to receive all of the potential demand reduction benefits due to the operation of its self-generation, but requires a cost-based reservation charge to compensate DEP for guaranteeing the resources needed to serve the customer's load at any time. He believes that the Standby Service Contract Demand provision of the Company's proposed new Rider SS is appropriate in order to avoid subsidization by other ratepayers.

Witness Chriss also voiced two concerns regarding the Company's proposed pricing of Rider SS. He disagreed with the Company's use of the marginal generation cost from the Company's last avoided cost proceeding, Docket No. E-100, Sub 127, in calculating the Generation Reservation Charge. Witness Chriss testified that customers taking standby service will be overcharged for the Generation Reservation Charge if the Commission approves the proposed avoided costs in Docket No. E-100, Sub 136, the avoided cost proceeding currently pending. Instead, he recommended that at the conclusion of Docket No. E-100, Sub 136, the Commission should require DEP to file an updated Rider SS in which the Generation Reservation Charge is adjusted to reflect the approved avoided costs.

In addition, witness Chriss argued that the Company's use of marginal generation costs and pricing does not recognize the benefits of solar installations on DEP's system within the framework of the 1CP cost allocation methodology. He testified that customer-installed solar resources provide a benefit to DEP's system under the 1CP framework, but the peak day benefits of future installations will not be recognized due to use of the historical test year. To remedy this issue, he recommended that the Commission consider expanding to Rider SS the standby service exemption currently allowed under Rider NM, which waives standby charges for customers generating 100 kW or less.

CIGFUR witness Phillips recommended that customers receiving service under Rider No. 7 be allowed to continue under this rider and not be required to migrate to the new Rider SS. Through the March 19, 2013, Amendment to the Stipulation, the Company withdrew its request to terminate Rider No. 7.

In its Brief, Commercial Group asserts that Rider SS is unjust, unduly discriminates against customers installing solar generation, and creates an unreasonable barrier to the development of solar generation on DEP's system. In particular, Commercial Group submits that the general tariff of a MGS customer includes a charge for DEP to make power available to meet the customer's power needs, whether on or off-peak. Commercial Group contends that this same customer that installs solar generation at its facility would be forced to pay again for this availability under proposed Rider SS through a generation reservation charge (GRC). According to Commercial Group, this double charge discriminates against the customer choosing the solar generation option to meet a portion of its energy/demand needs, as compared to a customer choosing another option, such as day lighting, that may result in an identical change in demand from the same weather event. Further, Commercial Group maintains that this unfairness can be corrected by making the GRC charge the same for all Rider SS customers.

In addition, Commercial Group argues that the Commission should align the cost level of the GRC with DEP’s most up-to-date avoided costs, i.e., those that are being determined in Docket E-100, Sub 136.

In its Brief, NCSEA notes that DEP's proposed Rider SS generation reservation charge is a cost-based tariff. Further, NCSEA contends that a portion of the cost of the Rider SS generation reservation charge represents the recovery of a percentage of DEP's avoided costs. Because DEP’s avoided costs will change over time, NCSEA submits that the Commission should adopt a cost-based rider that will track DEP’s changing costs. According to NCSEA, the rider is needed to avoid potential overcharges of customer-generators, a possible under-recovery of costs by DEP, and a failure to achieve the integrated regulation Chapter 62 was designed to achieve. With regard to this last point, NCSEA cites the decision of the North Carolina Supreme Court in State ex rel. Utilities Com. v. General Tel. Co., 285 N.C. 671, 680, 208 S.E.2d 681, 687 (1974), in which the Court states that “Chapter 62 provides for the granting of a monopoly and for the regulation of its service and its charges by the Utilities Commission. The entire chapter is a single, integrated plan. Its several provisions must be construed together[.]” NCSEA also cites similar language in the Supreme Court's April 12, 2013 decision in State ex rel. Utils. Comm’n v. Cooper, __N.C.__, 739 S.E.2d 541, 548 (2013).

In the alternative to a cost-based rider, NCSEA contends that the Commission should base the Rider SS generation reservation charge on DEP’s proposed 2012 avoided costs, not on DEP’s 2012 IRP-based avoided costs, for at least two reasons. First, NCSEA believes that DEP's IRP-based avoided costs may be based on outdated and inaccurate information. Second, NCSEA believes that its approach of basing Rider SS costs on to-be-adopted avoided costs is similar to that advocated by Duke Energy Carolinas, LLC, in seeking to incorporate its 2012 proposed avoided costs into Duke's 2012 DSM/EE cost recovery rider.

In his rebuttal testimony, Company witness O’Sheasy explained that the Rider SS Generation Reservation Charge is priced to recover 15% of the Company’s estimated marginal generation cost; this percentage is based on the planning capacity reserve margin in the Company’s IRP. He explained that current marginal capacity cost is lower than the avoided cost used for pricing purposes in this case. In the Stipulation, the Public Staff and Company agreed to use an avoided cost rate of $5.90/kW for the new LLC Rider. Witness O’Sheasy explained that because the same cost basis is used in pricing the Rider SS reservation charge, the requested Rider SS reservation charge should be reduced from $0.98/kW to $0.89/kW to be consistent with the Stipulation. Witness O’Sheasy also responded to the Commercial Group’s criticism of Rider SS’s impact on customer-installed solar resources, testifying that for generation with a planning capacity factor of 60% or less, the reservation rate proposed in Rider SS is 29% less than the currently applicable rate under Standby Service for Solar-Electric and Wind-Powered Generation Rider SSSW.

The Commission is not persuaded by the recommendation of Commercial Group witness Chriss that the Company should be required to define the Standby Service Contract Demand for all types of generation in the same manner. The Commission gives substantial weight to the testimony of Public Staff witness Floyd that when a customer installs self-generation and requires standby service for times when the self-generation is not operating the Company must plan and maintain sufficient generation facilities to meet the customer's demand, and the cost of those facilities should be taken into account in setting the rates for standby service. An example provided by Company witness O'Sheasy is that of renewable generation customers with planning capacity factors below 60% being different from those with planning capacity factors greater than 60%. Thus, the Company is responsible for planning and constructing its generating facilities to meet these differences. The Commission finds this testimony to be entitled to significant weight.

In addition, the Commission is not convinced that it should adopt the recommendation of witness Chriss to apply the standby service exemption currently allowed under Rider NM, which waives standby charges for customers generating 100 kW or less, to Rider SS. In its assessment of this issue, the Commission gives significant weight to the Stipulation and the testimony of witness O'Sheasy. The Stipulation calls for the use of an avoided cost rate of $5.90/kW for the new LLC Rider. Witness O'Sheasy explained that because the same cost basis is used in pricing the Rider SS reservation charge, the requested Rider SS reservation charge should be reduced from $0.98/kW to $0.89/kW to be consistent with the Stipulation. In response to the Commercial Group's criticism of Rider SS's impact on customer-installed solar resources, witness O'Sheasy testified that for generation with a planning capacity factor of 60% or less, the reservation rate proposed in Rider SS is 29% less than the currently applicable rate under Standby Service for Solar-Electric and Wind-Powered Generation Rider SSSW.

Further, the Commission does not find persuasive the argument of Commercial Group that Rider SS is unjust or unduly discriminates against customers installing solar generation. Generally, all tariffs include a charge for the utility to make power available to meet the customer's needs, whether on or off-peak. When a customer installs solar generation, it creates an additional planning factor that the utility must consider in order to have sufficient generation available to meet that customer's need when the solar generation is not operating. The Company's proposed generation reservation charge is appropriate for that purpose.

Moreover, the Commission is not persuaded by NCSEA's arguments for three reasons. First, biennial avoided costs are established by the Commission pursuant to the Public Utility Regulatory Policies Act of 1978 (PURPA), not Chapter 62. The goal underlying PURPA's avoided cost provisions is mainly the development of small wholesale power producers. On the other hand, the "single, integrated plan" of Chapter 62 cited by the Supreme Court in the General Telephone and Cooper decisions is in reference to the Commission's role in setting retail rates for utilities providing monopoly service, a very different function.

Second, rate riders have generally been established by the legislature, as is the case with the fuel, DSM/EE and REPS riders. The Commission has created such riders very sparingly, only when justified by volatile, temporary or unanticipated costs. The cost of Rider SS does not meet those criteria.

Third, the Commission concludes that it should not set Rider SS costs in this docket based on what the Commission might decide in the avoided cost docket.

Based on all of the evidence, the Commission finds and concludes that the Company's new Riders SS and NFS, as proposed by Company witness O'Sheasy, are just and reasonable to all parties. In accordance with the Stipulation, the Company shall implement its proposed new Riders SS and NFS; terminate its Rider No. 66, Rider SSSW, and existing Riders SS and NFS; and transfer any existing participants in these riders to the new Riders SS and NFS as appropriate.

Schedule LGS-RTP

The Company proposed to retain the current limit of 85 participants for its LGS Real Time Pricing Schedule LGS-RTP. Company witness O'Sheasy explained that LGS-RTP is a complex rate design and requires daily support to calculate hourly rates, monitor consumption for each participant, and download usage information to a real time pricing (RTP) website to assist participants in responding to the hourly price signals. Furthermore, extensive interaction with participants is required to create Customer Baseline Load billing at least annually to reflect the customer's operation. According to witness O'Sheasy, because LGS-RTP participants require much more attention than standard tariff customers, it is difficult to manage a greater number of participants than 85.

During cross-examination by counsel for NCLM, witness Coughlan recommended that the Company remove the current cap on participation in its LGS-RTP program. In rebuttal, witness O'Sheasy testified that the current cap is not being met today, nor does it appear that it is going to be met, and that DEP has never turned away a customer that requested RTP because of the cap. Witness O'Sheasy went on to explain that LGS-RTP is not an easy tariff to administer, as there are significant price development costs, price transmission costs, customer accounting expenses, and billing expenses. He added that there is a lot of "customer handholding" involved in explaining to RTP customers why these prices are what they are. Witness O'Sheasy concluded that the cap enables the Company to keep its administrative costs at a reasonable level and should be retained.

The Commission finds witness O'Sheasy's testimony that DEP's 85-customer cap on participation in LGS-RTP has yet to be exceeded to be credible and agrees that there is no reason to remove the limit on participation in LGS-RTP in light of this evidence. Moreover, the Commission finds that the 85-customer limit is reasonable at this time to ensure adequate program management given the substantial costs involved in administrating LGS-RTP.

Residential Basic Customer Charge

In its Brief, NC WARN contends that the proposed increase in the residential basic customer charge (BCC), from $6.75 to $11.50 under the Stipulation, is highly regressive and discriminatory because as a fixed rate increase the impact on low-income and low usage residential customers is higher than the impact on other residential customers. NC WARN maintains that this results in unreasonable discrimination in violation of the criteria set forth in State ex rel. Utilities Commission v. N.C. Textile Manufacturers Association, Inc., 313 N.C. 215, 328 S.E.2d 264 (1985), and is contrary to the State policy under G.S. 62-2(a)(3) that utility service should be economical. NC WARN recommends that the Commission create a lower residential BCC for lower-usage customers.

With regard to NC WARN's recommendation, the Commission concludes that a tiered approach to the residential BCC would be inconsistent with the general principle that where feasible a utility's fixed costs should be recovered by fixed charges. The fixed cost of serving a low-usage residential customer is the same as the fixed cost of serving a high-usage residential customer. In addition, NC WARN's recommendation would not necessarily benefit the customer group that it seeks to benefit, low-income customers. A residential customer may be a low-usage or high-usage customer irrespective of whether the customer's income is in the low, middle or upper income bracket. Low-income residential customers in subsidized or rental housing often have high usage.

Summary With Respect to Rate Design

Based on the testimony of witness O'Sheasy, with consideration of the testimony of witnesses Coughlan, Higgins, Howe, Chriss, Rosa, Phillips, and Floyd, as well as the agreement of the Stipulating Parties, the Commission finds and concludes that the rate design provisions in Paragraph 5 of the Stipulation are just and reasonable to all parties in light of all the evidence presented.

EVIDENCE IN SUPPORT OF FINDING OF FACT AND CONCLUSION NO. 28

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

Company witness Yates provided testimony regarding DEP's performance with regard to customer service. He stated that DEP has been recognized for providing excellent customer service. Both the 2012 J.D. Power residential customer and business customer surveys ranked the Company in the top quartile of all large utilities nationally. DEP has been in the top quartile nationally for the residential customer survey for ten straight years and in the top quartile for the business customer survey for ten of the last 11 years. Additionally, in 2005, the Company was awarded the J.D. Power and Associates Founder's Award for its dedication, commitment, and sustained improvement in serving customers. DEP is the only company in the utility industry to receive this award.

Witness Yates also explained that DEP continues to enhance its customer service practices to address language, cultural and disability barriers. Among other accommodations, DEP's customer service center offers customer service and correspondence in the Spanish language, handles calls from TTY devices (text telephones), offers bills in Braille, and accepts pledges from social service agencies to assist in the payment of customers' bills.

No intervenor offered any evidence contradicting the agreement of the Stipulating Parties that the quality of DEP's service is good. Therefore, consistent with Paragraph 7 of the Stipulation, the Commission finds and concludes that the overall quality of electric service provided by DEP is good.

EVIDENCE IN SUPPORT OF FINDING OF FACT AND CONCLUSION NO. 29

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

Company witness Newton explained that as part of the settlement with the Public Staff the Company will convert $20 million of a regulatory liability for the benefit of the Company’s North Carolina retail customers to be allocated among (a) local agencies and organizations for programs that provide assistance to low-income customers, and (b) programs that provide training to improve worker access to jobs and increase the quality of the workforce.

At the hearing, witness Newton explained that the Company is mindful of the fact that it is requesting an increase at a time when many customers are struggling. He testified that the Stipulation reflects a constructive approach that allows the Company to maintain its financial strength and credit quality, and that it positions the Company to continue to provide high quality service to customers, while also mitigating the impact of this rate increase on customers. According to witness Newton, one of the key ways the Stipulation reduces the impact of the rate increase on customers is through the Company’s agreement to contribute $20 million in funds that can be used right away to help those most in need. He explained that the Company will convert $20 million of its Account 108, a regulatory liability associated with the Company’s anticipated costs of decommissioning and removing equipment that is past its useful life.

No party offered any evidence opposing this provision of the Stipulation. Therefore, the Commission finds and concludes that the Company’s plan to use $20 million of a regulatory liability to provide assistance to low income customers and support workforce development, as set forth in Paragraph 8.A. of the Stipulation, is a just and reasonable measure to mitigate the impact of the proposed rate increase on DEP's low-income customers. The $20 million will be sourced from the portion of the current balance in the Company’s FERC Account 108 that consists of the accrual for the Company’s anticipated costs of decommissioning and removing equipment that is past its useful life. The Company shall consult with the Public Staff and submit a specific proposal for distribution of the funds within 60 days of this Order for Commission review and approval.

EVIDENCE IN SUPPORT OF FINDING OF FACT AND CONCLUSION NO. 30

The evidence supporting this finding of fact and conclusion is contained in the verified Application, DEP’s Form E-1, the testimony and exhibits of the witnesses, the Stipulation, and the entire record in this proceeding.

Company witness Wiles testified that the North Carolina retail portion of the Company’s nuclear decommissioning expense during the test year was $20.5 million. He observed that this figure is based on DEP’s July 14, 2010, Decommissioning and Funding Report filed in Docket No. E-100, Sub 56 (Funding Report). According to witness Wiles, the Funding Report assumed that a government repository for spent fuel located at Yucca Mountain would begin accepting spent fuel in 2020. He explained that the federal government, however, has since closed Yucca Mountain and created a Blue Ribbon Commission on America’s Nuclear Future (BRC) to review policies for managing the back end of the nuclear fuel cycle and recommend a new plan. Witness Wiles testified that given the uncertainty around the timing of the new plan, DEP updated its assumption regarding disposal of spent nuclear fuel, anticipating that a repository would be available no sooner than 2030. Further, witness Wiles testified that DEP's updated calculation of nuclear decommissioning expense also included, among other things, the following assumptions: (a) a 3% escalation rate for future decommissioning costs; (b) a 0% real rate of return on decommissioning funds during the decommissioning period; and (c) an updated NC retail allocation factor based on the year 2011. Witness Wiles stated that DEP's updated calculation results in an increase in funding requirements of $20.3 million, for a total of $40.8 million of nuclear decommissioning expense for the North Carolina retail jurisdiction. He testified that DEP's next nuclear decommissioning study is not due to be completed until 2014, and, therefore, he submitted that the $20.3 million increase is the most reasonable estimate currently available to the Company until the BRC issues an updated timeline for the opening of a spent fuel storage facility.

Public Staff witness Hinton expressed concerns regarding two of DEP's assumptions utilized in the Company's calculation of nuclear decommissioning expense for the North Carolina retail jurisdiction – the 3% escalation rate for future decommissioning costs and the 0% earnings rate on decommissioning funds during the decommissioning period. Witness Hinton testified that the Public Staff's review revealed that the escalation rate for the projected decommissioning costs is a composite of the escalation rates for each of DEP's four nuclear units plus the Robinson Independent Storage Fuel Storage Installation (ISFSI). He explained that DEP determined the projected escalation rates by weighting various cost elements unique to each unit that are needed to complete the decommissioning process. DEP then escalated the cost elements using forecasts obtained from Moody's Analytics and Energy Solutions, Inc., and took a simple average of the results to arrive at a composite escalation rate of 2.75%, which it rounded up to 3%. The Public Staff supports the use of weighted cost elements to reflect the expected future costs associated with each unit. However, witness Hinton contended that the simple averaging process used by DEP was inappropriate, as it results in equal weighting of the projected decommissioning costs for each of the four units and the ISFSI, which constitute widely varying percentages of the total, the ISFSI being less than 1%. Witness Hinton maintained that it is more reasonable to base the escalation factor on the ratio of the weighted inflated decommissioning cost of each facility to the total decommissioning costs of all the facilities. According to witness Hinton, this method is conceptually the same as the process DEP used in developing the escalation rate for each unit. The Public Staff's method results in an escalation factor of 2.6%, rather than 3%, which witness Hinton contended is more reflective of future decommissioning costs.

Regarding the 0% earnings rate, witness Hinton contended that by using a 0% real rate of return during the decommissioning period, DEP's model has assumed that decommissioning costs would be fully funded upon retirement of its nuclear plants. However, witness Hinton testified that the Public Staff is aware that the Nuclear Regulatory Commission (NRC) permits utilities, such as DEP, that provide funding assurance based on certain prescribed formula amounts to take a pro rata credit for projected earnings up to a 2% annual real rate of return for the first seven years of the decommissioning period. Witness Hinton maintained that this is a more appropriate assumption to use in DEP's model to determine the level of decommissioning expense to be recovered through rates in this proceeding. Not only is an assumption of a real rate of return during the decommissioning period consistent with NRC regulations, it is also consistent with assumptions used by Dominion North Carolina Power in its decommissioning cost and funding reports filed with this Commission. For these reasons, witness Hinton recommended that an assumed 2% real rate of return on tax-qualified funds and a 0.92% rate of return on nontax-qualified funds during the first seven years of the decommissioning period should be used in determining the decommissioning revenue requirement.

The Public Staff's recommended assumptions regarding the appropriate escalation and post-retirement earnings rates will result in an annual decommissioning expense of $7.6 million, as opposed to the $40.8 million proposed by DEP. The resulting adjustment including the tax impacts of nonqualified funds results in a net operating income increase of $31.7 million, such that the stipulated adjustment decreased the revenue requirement by $54 million.

The Company agreed to the Public Staff's decommissioning revenue requirement adjustment, and in return, the Public Staff agreed not to oppose the Company's deferral request for any changes in decommissioning cost and funding requirements based on future decommissioning studies filed with the Commission. The $54 million adjustment to the revenue requirement is reflected in Revised Settlement Exhibit 1 to the Stipulation.

The Stipulating Parties have demonstrated that the amount of nuclear decommissioning expense set forth in the Stipulation is reasonable and appropriate for the Company in this proceeding. None of the intervenors took issue with this provision of the Stipulation. The Commission finds that based on all of the evidence presented, the amount of decommissioning expense set forth in the Stipulation is just and reasonable to all parties.

EVIDENCE IN SUPPORT OF FINDING OF FACT AND CONCLUSION NO. 31

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

Company witness Bateman testified that DEP included in its Application a request for approval to implement a levelization methodology for its nuclear unit refueling outage expenses. She stated that DEP owns and operates four nuclear units, Brunswick Nuclear Units 1 and 2, the Harris Nuclear Unit, and the Robinson Nuclear Unit. These units are periodically taken out of service for refueling. Witness Bateman maintained that on average, the Company will experience seven refueling outages in a three-year period. She explained that the scheduling of these outages can result in anywhere from one to three outages in a calendar year. DEP currently expenses nuclear refueling outage costs in the month that the costs are incurred which results in significant variability in DEP's annual operating costs. In order to minimize the impact of this variability and to better match the refueling outage expenses with the period over which the benefit is realized, witness Bateman proposed to levelize the expenses associated with these refueling outages by deferring the actual incurred outage expenses and amortizing them over the period of the operating cycle between scheduled refuelings for the unit, beginning January 1, 2013. In conjunction with the proposed accounting methodology, the Company is requesting authorization from the Commission to establish a regulatory asset on its balance sheet.

Public Staff witness Hoard testified that because there is a separate adjustment that annualizes labor expenses as of December 31, 2012, base labor expenses have been removed from the computation of the nuclear refueling outage cost adjustment to avoid double-counting labor expenses. In the computation of the stipulated adjustment, labor expenses have been excluded from both the normalized level of nuclear refueling outage costs and the actual test year level of such costs.

As set forth in the Stipulation, the Public Staff agreed not to contest the Company's normalization proposal. Settlement Exhibit 2 to the Stipulation sets forth the agreement between DEP and the Public Staff regarding the establishment of a regulatory asset on the Company's balance sheet to accumulate nuclear outage expenses in a deferred account and then expense them over the nuclear unit's refueling cycle. Public Staff witness Hoard explained that under Settlement Exhibit 2, the deferred costs would be amortized to expenses over 24 months for each of the Brunswick units and over 18 months for the Harris and Robinson units. For each unit, the amortization would begin the second calendar month following the completion of the unit's refueling outage and continue for the length of the operating cycle until the second month after the next scheduled refueling. In the event that a unit is permanently retired from service, a different amortization period for nuclear refueling outage costs that were incurred prior to the end of a nuclear unit's operating life and have been deferred, but not yet amortized to expenses, could be deemed appropriate by the Commission, as long as the Company is allowed to recover the costs. Specific details regarding the types of incremental costs eligible for deferral are provided in the Levelization Attachment 1, included in the Stipulation.

Witness Bateman testified that this methodology is consistent with standard and accepted ratemaking principles. According to witness Bateman, the levelized accounting methodology provides a fair and reasonable approach to match the Company's outage costs with the period during which customers receive the generation benefits from its nuclear units.

Pursuant to Settlement Exhibit 2, the establishment of the deferral accounting method for nuclear outage costs would not prejudice the right of any party to raise issues of prudence and reasonableness of the nuclear refueling outage costs reflected in a Commission proceeding. No return would be proposed for ratemaking purposes on any unamortized balance, either by inclusion of any unamortized balance in rate base, by incorporation of a return in the expense amount, or by other means. All amortization expenses would be included in cost of service and surveillance reporting, and would also be included in future general rate cases.

No intervenor took issue with this provision of the Stipulation. The Commission has reviewed the levelized accounting methodology set forth in Settlement Exhibit 2 to the Stipulation. The Commission agrees that this provision represents an appropriate resolution of the issue by the Stipulating Parties, and finds and concludes that it is just and reasonable to all parties in light of all the evidence presented.

EVIDENCE IN SUPPORT OF FINDING OF FACT AND CONCLUSION NO. 32

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

In its Application, the Company included a pro forma, test-period, cost-of-service adjustment to amortize proposed deferred costs, including a return on investment, associated with its recently completed Wayne County generating facility (Wayne CC). Deferral of such costs had been requested by the Company in a petition filed in Docket No. E-2, Sub 1026 (Sub 1026). The Company proposed to amortize the Wayne CC deferral over a five-year period.

On March 22, 2013, the Commission approved the Company's deferral request for the Wayne CC in Sub 1026. In its Order, the Commission concluded that a 10.50% ROE was reasonable for use in determining the incremental cost of capital with respect to the Wayne CC deferral request.

As part of the Stipulation, the Company and the Public Staff agreed that it was appropriate to include amortization of the Wayne CC deferred costs in the Company's revenue requirement. Public Staff witness Hoard testified that the stipulated amortization was computed in a manner consistent with the Commission's computation of similar amortizations in past cases. In particular, Hoard testified that the stipulated amortization reflected the following changes to the Company's computation:

(1) Adjustment to the computation of the cost of capital for December 2012 and January 2013;

(2) Reflection of the monthly cost-of-capital percentages used in the computations of the deferral and levelized amortization amounts to produce the proper annual cost-of-capital amount. The Company used the annual rate divided by 12 to determine the monthly cost-of-capital percent and the amount of its deferred return. Using this method overstates the cost of capital due to the effect of compounding. The computation of the deferral and amortization has therefore been adjusted so as to produce the target cost of capital, on an annual basis;

(3) Adjustment to the return on deferred costs to include a return on the deferred capital costs;

(4) Adjustment to the monthly cost of capital used in the computation of the return on deferred costs to reflect the after-tax rate, instead of the pre-tax rate used by the Company. It is appropriate to use the after-tax rate so that all of the tax benefits related to the deferred costs are recognized in calculating the return;

(5) Adjustment to the monthly cost-of-capital percentage used in the computation of the levelized amortization amount to reflect the stipulated capital structure and cost rates in this case, compounded annually, based upon mid-year cost recovery;

(6) Adjustment to the Company's calculation of the deferral balance for the Wayne transmission plant by (a) removing accumulated deferred income taxes that were included by the Company in error; (b) correcting the calculation of the depreciation reserve balance; (c) correcting the calculation of the beginning rate base balance for January 2013; and (d) correcting the calculation of the total costs for deferral to include the amounts for December 2012;

(7) Removal of property tax expense for December 2012, since the plant was placed in service on December 31, 2012;

(8) Adjustment to the depreciation rate used to calculate the deferred depreciation expense for production plant to reflect the depreciation rate for the Wayne CC calculated by the Company in its adjustment to include the Wayne CC in rate base; and

(9) Adjustment to the amount of transmission plant placed in service in December 2012 to reflect the amount included in the Company's adjustment to include the Wayne CC in rate base.

No intervenor presented any substantial evidence with regard to this provision of the Stipulation.

In consideration of the foregoing, the Commission finds and concludes that this provision of the Stipulation represents an appropriate resolution of the Wayne CC deferral issue and that it is just and reasonable to all parties in light of the evidence presented.

EVIDENCE IN SUPPORT OF FINDING OF FACT AND CONCLUSION NO. 33

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

Company witness Bateman provided testimony regarding the storm cost normalization adjustment. She explained that the Company included in its Application a pro forma adjustment to the Company's total revenue requirement to normalize storm expenses. Witness Bateman testified that the adjustment normalizes the storm restoration expenses, excluding internal base labor, incurred during the test period to an average level experienced by the Company over the last ten years. As set forth in Paragraph 8.H. of the Stipulation, the Public Staff has accepted the Company's proposed pro forma adjustment to normalize the level of operations and maintenance expense related to storm costs. The Stipulating Parties agreed to include an adjustment to cost of service to normalize storm restoration costs for the test period in this proceeding. However, the Public Staff has reserved the right to oppose a request by the Company to defer and amortize future storm restoration costs.

No intervenor took issue with this provision of the Stipulation. The Commission agrees this provision represents an appropriate resolution of the issue by the Stipulating Parties and finds and concludes that it is just and reasonable to all parties in light of all the evidence presented.

EVIDENCE IN SUPPORT OF FINDING OF FACT AND CONCLUSION NO. 34

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

Company witness Bateman testified that the Company adjusted its coal inventory balance at the end of the test year to reflect DEP's proposed target number of days of coal inventory at each plant. For purposes of developing this adjustment, witness Bateman stated that the Company removed the coal inventory balances at the Lee, Cape Fear, and Robinson coal plants to reflect the Company's current plan to retire these facilities prior to the close of the hearing in this proceeding.

In response to a Public Staff data request, the Company stated that the target inventory level used for its adjustment was 50 days. Public Staff witness Ellis testified that the Public Staff does not consider 50 days to be an appropriate target inventory for the Company. The Public Staff contended that DEP's coal inventory was increased to 50 days due to lower power demand caused by economic conditions and the arrival of contracted, scheduled deliveries of coal to the utility's plants. In addition, the Public Staff asserted that current natural gas prices have resulted in natural gas generation being dispatched ahead of DEP's coal generation fleet, further causing coal inventories to build. The Public Staff opined that the increased inventory is not representative of normal levels and should be temporary. The Public Staff observed that DEP's coal consumption has actually decreased and contended that it would not be expected to increase significantly in the near future. Because of the expected continued decrease in coal consumption and the fact that DEP's actual experience has been to operate with a lower inventory, witness Ellis contended that 40 days of inventory is sufficient to enable the Company to dispatch its coal generation when needed without imposing excessive costs on ratepayers. He noted that the Public Staff does not contend that the Company's coal contracting practices or the Company's reduced dispatch of its coal generation fleet has been imprudent.

The Stipulating Parties agreed to an increment rider to allow the Company to recover the additional costs of carrying coal inventory in excess of a 40-day supply. Settlement Exhibit 1 to the Stipulation incorporates an adjustment that decreases the target inventory of coal to 40 days of full load burn. Witness Bateman testified that the coal inventory rider contained in the Stipulation is important to allow the Company to recover its prudently incurred coal inventory costs. She explained that the base rates in the Stipulation are based on 40 days of coal inventory and that the Company will recover coal inventory carrying costs in excess of a 40-day supply through the rider. Bateman Rebuttal Exhibit 3 shows the calculation of the rider to become effective along with the new base rates approved in this proceeding. It also shows that the rider will expire at the earlier of (a) November 30, 2014, or (b) the last day of the month in which the Company's actual coal inventory levels return to a 40-day supply on a sustained basis[1] to allow the Company to recover the additional costs of carrying coal inventory in excess of a 40-day supply (priced at $91.623 per ton). The Stipulation further provides that the Company may request an extension of the November 30, 2014 date. The Stipulating Parties agreed that any over- or under-collection of costs experienced as a result of this rider will be trued up at the time of the proceeding held to set DEP's DSM/EE Cost Recovery Rider, Renewable Energy and Energy Efficiency Portfolio Standard (REPS) Rider, and Fuel Adjustment Rider. Any interest on over- or under-collection shall be set to the Company's net of tax overall rate of return, as approved by the Commission in this proceeding.

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[1] For this purpose, the Stipulating Parties agreed that three consecutive months of total coal inventory of 42 days or below will constitute a sustained basis.

The Commission finds and concludes that the increment rider to allow the Company to recover the additional costs of carrying coal inventory in excess of a 40-day supply, as proposed by the Stipulating Parties, is just and reasonable to all parties in light of all the evidence presented.

EVIDENCE IN SUPPORT OF FINDING OF FACT AND CONCLUSION NO. 35

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

As fully discussed in Findings of Fact and Conclusions Nos. 7-34, the provisions of the Stipulation are the product of the give-and-take of settlement negotiations between DEP and the Public Staff. As a result, the Stipulation reflects the fact that DEP agreed to certain provisions that advanced the Public Staff's interests, and the Public Staff agreed to other provisions that advanced DEP's interests. The end result is that the Stipulation strikes a fair balance between the interests of DEP and its customers. The Stipulation is just and reasonable to all parties in light of the evidence presented and serves the public interest. Therefore, the Commission approves the Stipulation in its entirety.

EVIDENCE IN SUPPORT OF FINDING OF FACT AND CONCLUSION NO. 36

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

Company witness Hopkins’ direct testimony describes and supports the Company’s summer coincident peak (1CP) cost of service study. Witness Hopkins recommended the use of the summer peak coincident demand as a reasonable and appropriate cost allocator for DEP's production and transmission fixed capacity costs. Witness Hopkins explained that the 1CP method allocates costs based on contribution to the system’s annual summer peak demand. Each jurisdiction’s and customer class’s cost allocation factor is equal to the ratio of their respective demand to the total system demand during the hour of the system’s annual peak. The 1CP allocation factor recognizes that having necessary generation and transmission resources in place to meet the annual peak hour is the essential planning criteria of the Company’s system and that all classes should share equally their responsibilities in creating the planning peak.

DEP was ordered by the Commission to use the Summer Winter Peak and Average (SWPA) methodology in North Carolina in its last general rate case. Prior to 1980, DEP used the 1CP method, but the Commission ordered the change to SWPA in the context of the Company’s 1982 general rate case in Docket No. E-2, Sub 444 based upon the Public Staff’s recommendation. At that time, the Public Staff recommended SWPA based on concerns with the increasing size of the Company’s winter season peak load. Witness Hopkins testified that his review of the Company’s history now indicates that despite the apparent concern by the Public Staff over 20 years ago that the winter season peak would influence the cost causation of the production and transmission systems, this has not occurred.

According to Witness Hopkins, the Company's resource planning process does not support the use of the SWPA methodology. Over the past 25 years, the Company has only experienced 5 winter peaks. Over that same period, the summer peak has exceeded the winter peak by an average of 6%, and has been as great as 21% higher than the corresponding winter peak. Additionally, through its integrated resource planning process, the Company continues to plan its future resource needs in order to meet its projected maximum summer load obligation, plus a reserve margin. Over the fifteen year planning horizon of the Company's 2012 Integrated Resource Plan (IRP), the average winter reserve margin is more than 14 percentage points higher than the average summer reserve margin. Witness Hopkins concluded that the summer peak continues to drive the Company's resource planning process. Company witness Newton also confirmed that summer peak hours clearly drive the Company's capacity planning.

Witness Hopkins also testified that the use of the SWPA methodology disproportionately impacts high load factor customers, resulting in large commercial and industrial classes having more than the average cost per kW allocated to them. According to Witness Hopkins, the SWPA model is flawed in that (1) it allocates jointly incurred production costs in a differential manner between classes, and (2) there is no recognized lower energy costing counter balance made in support of the theory for the higher and lower assignment of capacity costs to certain classes. Witness Hopkins concluded that arbitrarily allocating fixed production demand costs based on average class loads and the non-planning winter peak serves only to exaggerate cost responsibilities of certain higher load factor user classes.

Witness Hopkins noted that the economy of the Company's service territory is experiencing growth issues that can be accentuated by misplacing cost responsibilities in a costing study. Witness Hopkins stated that DEP's reduced load growth over the last 5 years is traceable to a decline in large commercial and industrial activity, reflecting the more national trend in the economy. Witness Hopkins therefore concluded that it is important in this economy that any arbitrary or unreasonable cost burdens included in the costing process, and affecting rates to industrial and commercial customers be moderated.

Witness Hopkins also testified that the use of the 1CP method will best coordinate the cost study results for the Company with that of its South Carolina jurisdictional operations, as well as the cost study allocation used by its sister North Carolina operating company, Duke Energy Carolinas, LLC, with which it will ultimately be merged at some point in the future. Witness Hopkins noted that the Company's use of SWPA in North Carolina is an anomaly; Duke Energy Carolinas and DEP's South Carolina jurisdictional operations both use coincident peak methodologies. Witness Hopkins explained that methodological consistency between jurisdictions is important to enable the Company to recover all of its costs, and that continued use of the SWPA method in North Carolina could be detrimental to the Company and its customers.

CIGFUR witness Phillips also recommended that DEP use the 1CP cost of service study in this proceeding. According to witness Phillips, the 1CP method properly allocates cost responsibility to customer classes and, if implemented properly, minimizes the need for new generating capacity consistent with the Company's load management goals. Witness Phillips testified that DEP's growth in sales and peak demands are caused by classes other than the industrial class. Therefore, any need to increase generating capacity is not attributable to industrial customers. Witness Phillips states that the SWPA cost of service study recommended by the Public Staff should not be used in this proceeding because it over allocates fixed costs to high load factor customers, double counts loads by using a full average component and a full peak component, and it is not symmetrical because it does not allocate lower fuel costs to coincide with the above-average capital costs allocated to high load factor customers.

According to CIGFUR in its Brief, Public Staff witness McLawhorn explained that the starting point for the Public Staff's planning process is "both the capacity of the plant and the energy production capability." T, Vol. 6, at 25:8–13. The divergence in starting points in the planning process leads to the divergence in views as to the appropriate cost of service allocation methodology.

However, according to CIGFUR, DEP is the entity actually engaging in the planning process, not the Public Staff. The Company employs a full time staff dedicated to planning its capacity needs. DEP makes billions of dollars in capital expenditures based on the outcomes of its planning analyses—outlays that may only be recovered to the extent they were reasonably and prudently incurred. DEP puts its investors' money behind its planning process. How DEP actually conducts its planning process should be given weight. CIGFUR acknowledges that the Company agreed to propose the 1CP cost of service methodology in its settlement agreements with CIGFUR and CUCA in the merger docket, but submits that this fact does not mean that 1CP is somehow an inappropriate method in this proceeding or that DEP's proposal to use it is suspect or should be accorded any less weight. To the contrary, DEP has been proposing, and for the most part using, 1CP for decades, in this jurisdiction and others. In addition, 1CP best matches how the Company plans its capacity needs.

CUCA witness O'Donnell also testified in support of the Company's use of the 1CP methodology in this case. Witness O'Donnell testified that because DEP builds generating plant to meet the peak demand on its system, it makes sense to allocate generation investment by the coincident peak ratio. Witness O'Donnell explained that the residential customer class is the most temperature-sensitive and time-sensitive class. The time that residential customers use the most electricity is during a hot summer day, during the late afternoon, after-work hours, which causes the Company to ramp up its most expensive generating plants to meet demand. Industrial customers' energy consumption, however, stays relatively level and is much less sensitive to fluctuations based on time and weather. Witness O'Donnell concluded that because DEP's system was designed to meet its peak load, the 1CP methodology best captures how the Company dispatches its plant to meet the peak load.

In its Brief, CUCA argued that electric power plants are constructed so that an electric utility company can serve all customer loads that are on-line during its system peak, together with a reasonable reserve margin. Electric utility companies do not run "short" of energy; instead, they may run short of demand capacity. DEP is a summer peaking company and, for at least the last 20 years, the need for additional generating plant at DEP has been driven by the erosion of reserve margin at DEP's summer system peak. The 1CP methodology focuses on the contributions to summer peak demand by the various customer classes – e.g. Residential, Commercial and Industrial.

According to CUCA, SWPA, on the other hand, assumes that "energy" is a more important factor than "demand" in driving decisions by DEP to build additional generating plant.

The underlying assumption of SWPA is simply not justified by sound engineering principles of system design. The primary flaw of the SWPA methodology is that it takes what is exclusively a fixed, demand-related cost and attempts to allocate it onto customer classes on the basis of a variable component – energy consumption. Use of the SWPA unfairly rewards low-load factor customers, such as residential, and unfairly penalizes high load factor customers, such as industrials, whose constant demands for both power and energy help the overall electrical system to perform more efficiently and help hold down rates for all other customer classes. As noted by DEP witness Hopkins, SWPA may be fine as "social engineering" but it is very poor as a means of cost allocation.

Public Staff witness McLawhorn testified in support of the SWPA methodology. Witness McLawhorn explained the SWPA method allocates fixed capacity costs on the basis of a two-pronged formula. The first component, the "summer/winter peak" (or the "demand" component), is based upon the contribution of each jurisdiction and class to the Company's summer and winter peaks. The second component, the "average" (or the "energy" component), seeks to take into account energy consumed during the remaining hours of the year, and is calculated by dividing by jurisdiction and class the number of kilowatt-hour (kWh) sales for the year by the number of hours in the year to arrive at an average demand over the course of the entire year. The two prongs of the formula are then weighted to produce each jurisdiction's and each class's contribution to fixed capacity costs. In the end, the energy component is more heavily weighted, such that 55% of the resulting jurisdiction/class contribution is assigned to the energy component, and 45% is assigned to the demand component.

Witness McLawhorn testified that the SWPA methodology more accurately reflects actual generation planning and customer usage than does 1CP because SWPA takes into account that a portion of plant costs, particularly for base load generation, is incurred to meet annual energy requirements and not solely to meet peak demand. He criticized 1CP as follows:

> Under the 1CP methodology, production plant and related expenses, such as depreciation and accumulated depreciation, purchased power capacity costs, and certain production operation and maintenance (O&M) costs are allocated based on the loads (that is, the level of demand) of a jurisdiction and its customers during just one specific hour of the year -- the system peak. The remaining 8,759 hours of energy consumption (or 8,783 hours in this case because the test year included a leap day) are not recognized under this methodology for the purpose of allocating production plant cost responsibility of the North Carolina jurisdiction and its customer classes.

(T, Vol. 4, at 234.) Witness McLawhorn also pointed out that certain customer classes, such as street lighting, can avoid responsibility for any production plant cost if it has no consumption during the one hour summer peak. The Public Staff believes that the 1CP methodology is flawed because customers that are able to reduce their load during the summer peak hour can avoid paying for a significant portion of plant, even though their loads are present during other high demand periods throughout the year. McLawhorn also testified that by employing an average component, which is less likely to vary significantly year to year, SWPA is less likely to result in allocation swings due to weather anomalies occurring in the test year as compared to 1CP. Witness McLawhorn also responded to witness Hopkins' testimony regarding the Company's need for jurisdictional consistency. Witness McLawhorn testified that the risk of over-or under-recovery due to the use of different cost allocation methodologies is a risk that the Company assumed by choosing to operate in different jurisdictions.

NC WARN witness Marcus also testified regarding the Company's cost of service methodology. NC WARN opposed DEP's proposed use of the 1CP cost allocation method and recommended the use of the Average and Peak Demand (APD) cost allocation method in this case. Witness Marcus also recommended that in future rate cases, the Commission investigate other cost allocation methods, such as Loss of Load Probability (LOLP), top 100 hours for allocation of peak demand-related costs, and the probability of dispatch method.

Witness Marcus explained that energy requirements dictate the types of generation a utility builds. Generating plants are built to minimize total system costs and provide fuel diversity. Witness Marcus explained that to deal with peak energy demands, a utility will build a peaking plant which incurs lower capital costs, but higher fuel costs. On the other hand, to provide 'around the clock' energy, a utility will build a baseload plant, which incurs higher capital costs, but lower fuel costs. Witness Marcus argued that generating plant costs are not entirely caused by peak loads, and thus, DEP's use of the 1CP cost allocation methodology does not accurately reflect cost causation and results in residential and small business customers paying the most for new baseload construction.

Witness Marcus disagreed with witness Hopkins that generation is planned exclusively for summer peak. Witness Marcus asserts that generation needs are based on reliability, or LOLP. Witness Marcus argued that under the 1CP method, industrial customers pay less for plant construction than other customer classes. For example, according to witness Marcus, under 1CP, high load factor industrials pay less for a nuclear unit than for a combined cycle unit of equivalent cost, while residential and small business customers pay more.

According to witness Marcus, 1CP is rarely used by other utilities because the results are often unfair and the method is prone to gaming, such as when high load factor (HLF) customers partially self-interrupt after being informed that a peak event is likely to happen. Witness Marcus provided an overview of several alternative allocation methods, including the base-intermediate-peak method, the summer winter peak and average method, the plant capacity factor method, the probability of dispatch method, the marginal cost method, and the average and excess demand method. Witness Marcus' testimony reflects his belief that DEP selected the 1CP method in order to favor industrial customers and to achieve jurisdictional consistency, in light of the Company's merger with Duke Energy, even though 1CP is not the most reasonable cost allocation method.

NC WARN argues in its Brief that just as in DEP's last general rate case in 1988 the Commission should refuse to adopt the 1CP methodology. NC WARN submits that without some consideration of both demand and energy use the HLF customers will not pay their fair share. Citing the testimony provided by its witness, NC WARN states that Marcus described alternative rate measures that are fairer, more reasonable and more rationally reflect both the demand for electricity and energy usage. Further, witness Marcus testified that 1CP is rarely used because it does not reflect utility planning, actual use and system stress, and it does not produce fair and reasonable rates. Indeed, according to NC WARN the 1CP is often illegally discriminatory under the guidelines of State ex rel. N.C. Utilities Commission v. N.C. Textile Mfrs. Ass'n, Inc. (N.C. Textile Mfrs. Ass'n), 313 N.C. 215, 328 S.E.2d 264 (1985), because residential and small business customers are allocated most of the cost of new plant. Witness Marcus described several cost allocation methodologies that take energy usage into consideration. He recommended the APD method, a methodology that multiplies the system load factor by average demand (energy) and one minus the system load factor by a measure of peak demand. NC WARN submits that this is an appropriate alternative if the Commission does not adopt the SWPA.

In his rebuttal testimony, Company witness Hopkins responded to the testimony of witnesses Marcus and McLawhorn regarding cost allocation. Witness Hopkins testified that the cost allocation methodologies recommended by these witnesses are founded on the underlying theory that HLF customers cause the Company to incur the high capital costs of baseload units sufficient to meet both the system peak and their energy needs throughout the year. Witnesses Marcus and McLawhorn, therefore, conclude that HLF customers should be assigned a higher per unit (kW) facility cost. Witness Hopkins testified that the planning process upon which witnesses Marcus and McLawhorn base their recommendations also provides that the higher capital costs are occasioned to achieve lower energy costs and any meaningful and equitable use of their theories therefore must recognize this. Witness Hopkins notes, however, that neither witness Marcus nor witness McLawhorn acknowledges this tradeoff and the methodologies proposed by each of them allocate energy costs equally to all customers, resulting in a penalty to some classes and a boon to others. Furthermore, witness Hopkins stated, "There is no way to discern who's using what plant . . . . You can't say that the industrials are using the baseload and someone else is using the peak." (T, Vol. 7, pp. 35-36.) Witness Hopkins rejected the notion, put forth by witnesses McLawhorn and Marcus, that baseload is built to serve large load factor customers and not low load factor customers stating that "parsing of [variable energy] costs away from fixed capital cost is a poor enterprise." (Id. at p. 36.)

Witness Hopkins also addressed the argument that allocation methods that do not incorporate an energy use component, such as 1CP, allow certain classes to avoid any cost responsibility, such as street lighting on systems that peak during daylight hours. Witness Hopkins responded that this concern is properly addressed through rate design and not through cost allocation. Witness Hopkins stated that proponents of SWPA "fail to recognize that the assignment of the fixed costs . . . is in itself an arbitrary process, best left to value of service, social or operating efficiency determinations in the rate design, not imposed and hidden in allocation." (T, Vol. 6, p. 166.) In fact, Public Staff witness McLawhorn admitted on cross examination that the Public Staff has not conducted a detailed study to determine the appropriate weighting of the capacity and energy components under the SWPA method. Therefore, witness McLawhorn testified that an "approximation" is used to weight the average and peak components of the SWPA formula. Witness Hopkins testified that when cost allocation methods, like SWPA, interpret fixed costs as variable expenses, it results in a system that not only promotes inefficient use of resources, but encourages more wasteful use and inhibits pricing signals that encourage reasonable conservation by all customers. Witness Hopkins also recounted in his rebuttal testimony the history at FERC of "[a]ttempts to impose energy cost components on capacity-related fixed cost allocations," ultimately resulting in the FERC's decision in 1994 to abandon them because of their arbitrary nature. (Id., pp. 166-67.) He noted the Indiana Commission's rejection in 1995 of the concept of fixed capital costs being energy related as well.

Witness Hopkins testified that accurate cost allocation benefits all customers by promoting economic and efficient use of the utility's system at all times.

In his rebuttal testimony, witness Hopkins responded to witness Marcus' testimony regarding several alternative allocation methods, by noting that witness Marcus had not completed any factual examination of DEP's system and planning process either historically or into the future, which is the key element in its cost causation, and best method for cost allocation. Witness Hopkins also testified that the 1CP methodology is among the most widely recognized methods in the industry, and is used in North Carolina and South Carolina.

Witness Hopkins also reiterated that the Company's summer peak continues to be the prominent peak and the basis for the Company's generation planning. Witness Hopkins testified that the months surrounding the Company's peak during the twelve month test period shared very similar class relationships. He further explained that planning capacity to meet the annual system peak load adequately is the prime element of DEP's planning process, and the demands of each rate class at that time, not some other time, is the real basis for the costs. The selection of the types of units used by the Company's system beyond the need to meet the peak is a process of overall cost minimization reflecting the energy needs of all classes through the year, as well as many other factors. Witness Hopkins also criticized witness Marcus's recommendation to use the APD cost allocation methodology, stating that it is unsupported by any cost allocation analysis.

In his rebuttal testimony, witness Hopkins also responded to witness McLawhorn's recommendation to use the SWPA cost allocation methodology. Witness Hopkins testified that the Commission ordered DEP to change to SWPA in the Company's 1982 rate case based on the Public Staff's concern with the increasing size of the Company's winter peak. Three decades have passed since the SWPA method was accepted by the Commission, and this history, as well as the projections within the Company's 2012 IRP, has shown that the winter peak is not the primary basis for DEP's capacity planning.

Witness Hopkins testified that witness McLawhorn's critique of the 1CP method as being potentially susceptible to significant allocation swings due to weather anomalies is unsupported by any analysis. Witness Hopkins stated that an analysis of the Company's system summer peaks occurring for the test period shows in fact that it matters little whether the single peak is used or the peaks of the two surrounding months. He testified that hot weather conditions appear to have similar peak load percentage contributions occurring by class. Witness Hopkins also testified that witness McLawhorn's characterization of the Company's need to have jurisdictional consistency as a "risk assumed by the utility" is misplaced because continuing to use different cost allocation methods between jurisdictions is an actual risk to both the utility and its customers and should be addressed by the Commission. Witness Hopkins explained that "The aggregation of smaller utility properties into multistate and larger intrastate entities that has been underway for the last several decades has produced a vast array of synergy and other savings to the customer, but increasingly requires a commonly adopted methodology for sharing costs for the increasing mutual resources." (T, Vol. 6, p. 76)

Witness Hopkins also testified that he agreed with CUCA witness O'Donnell's testimony regarding cost allocation. Witness Hopkins testified that witness O'Donnell correctly pointed out the resulting cost message from the SWPA or the APD methods to customers is for large efficient users of the system to make their utilization worse, by lowering their load factors as energy-related costs are increased to them by these methods, and for the less efficient users to do the opposite, as demand costs are lessened. Witness Hopkins concluded that such results will only lead to increasing system costs for all customers as the system is less efficiently utilized.

Witness Hopkins also agreed with CIGFUR witness Phillips' testimony that any allocation method which increases the capital costs of the generation component to specific groups of customers must recognize that to be carried to a logical conclusion, the allocated energy costs need to be symmetrically treated to be equitable. Witness Hopkins, however, testified that in his opinion, the symmetrical treatment of energy costs is quite difficult to achieve, basically rendering the unequal treatment of the two components of generation costs, capacity and energy, impractical.

In DoD's Brief, DoD states that it supports 1CP as the method for determining cost of service in this matter.

In its Brief, DEP contends that the Commission's adoption of the SWPA for use by DEP in 1988 provides no guidance for the decision before the Commission in this case. For example, DEP notes that FERC and the Indiana Commission have ceased using SWPA because of the difficulty of using a variable energy factor to allocate fixed costs. Further, DEP submits that the Commission's approval of SWPA in the DNCP Rate Order should not be controlling precedent in the present case, as the Commission limited that order to the facts of that case.

In addition, DEP emphasizes the three strengths of 1CP noted by DEP witness Hopkins: (1) the Company plans its capacity needs based on its summer peak; (2) the Company's generation and transmission facilities are jointly used by all customer classes at all times and, thus, there is no basis for charging one class more for these joint costs; and (3) adoption of 1CP will support coordination between the jurisdictions in which DEP provides service.

The Commission, having considered all of the evidence, finds and concludes that the 1CP cost allocation methodology is reasonable and fair to all parties and appropriate for use in setting DEP's base rates at this time in this proceeding. The Commission gives the most weight to the testimony of witness Hopkins, which is essentially undisputed, that the Company experiences a dominant summer peak. Accordingly, with respect to the summer/winter focus of the SWPA methodology versus the summer peak focus of 1CP, the Commission finds and concludes that the 1CP methodology is appropriate for use in this case because the Company's summer peak has been and is projected to continue to be the dominant peak. In addition, as witness Hopkins fully explained, the 1CP method appropriately recognizes that having necessary generation and transmission resources in place to meet the annual peak hour is the essential planning criteria of the Company's system, and that all classes should share equitably in their responsibility in creating the planning peak.

A significant portion of Public Staff witness McLawhorn's testimony in support of SWPA rested upon the fact that DEP has been using SWPA and that this Commission recently adopted the SWPA in the DNCP rate case. However, on cross examination, witness McLawhorn conceded that the Company used the SWPA to file reports to this Commission and not as part of its planning process. Witness McLawhorn further acknowledged that the Company had not filed a general rate case in the past 25 years, could not unilaterally change the methodology and, thus, had no choice but to use the SWPA. He further conceded that in its recent rate case, DNCP requested SWPA as its cost allocation model. Moreover, as the Commission noted in its DNCP Rate Order, DNCP's cost of service witness testified that the SWPA methodology more closely matches its production planning process. (DNCP Rate Order, at 21.) This is in contrast to the testimony of Company witnesses Hopkins and Newton, who indicate that the summer peak drives the Company's planning process. Cost allocation is a complicated process and because each company is different it does not lend itself to a "one size fits all" approach. In fact, the Commission expressly noted in its Order in Docket No. E-100, Sub 133 that, "Evidence regarding the appropriate cost methodology is specific to each case." (Order Denying Rulemaking Petition, at 10.)

With respect to the "averaging" component of the SWPA formula espoused by the Public Staff, that is, the component based upon energy usage, the Commission has two concerns. First, there is inadequate evidence in support of the reliability of the "weighting" aspect of the formula. This is not a new concern of the Commission. Indeed, in the Company's 1982 rate case the Commission noted:

> Some members of the commission prefer that the matter not be considered as a final judgment based on the evidence presented in this case. For instance, the assigning of class cost responsibilities may have a significant effect or impact on the assignment of jurisdictional cost responsibilities. Thus, the Commission will follow with interest the methodologies adopted by regulatory bodies in other jurisdictions. In any event the commission, in adopting … [SWPA] in this proceeding does not preclude the possibility that additional data may indicate the need for considering and adopting some other methodology in future proceedings.

<u>In re Carolina Power & Light Co</u>., 55 P.U.R. 4th 582, 595 (NCUC 1983).

Second, the Commission notes that in this case it is undisputed that the Company's revenue request would have been $20 million higher had it performed its cost allocation on the basis of SWPA. Public Staff Witness Hoard testified in response to questions from the Commission as follows:

> Q: [D]oes it increase the Company's revenue requirement, the Summer-Winter Peaking over the Single Coincident Peak? Which one costs … more than the other one, is what I'm trying to say.
>
> A: [T]he gross revenue impact of moving from the Summer CP to a Summer-Winter Peak and Average – if you use a Summer-Winter Peak and Average it increases the revenue requirement by $20 million.

(T, Vol. 4, pp. 211-12.) Furthermore, in its Pre-Hearing Order Requiring Verified Information, issued on March 11, 2013, the Commission requested information "regarding the actual monthly billed amount to the average 1000-kWh residential customer" under both SWPA and 1CP. The Public Staff provided this information in Supplement to Revised Floyd Exhibit 1. If the Stipulation is approved, the bill under the SWPA method increases to $112.29 in Year 1 and to

$113.16 in Year 2. Under the 1CP method, the average monthly bill increases to $112.54 in Year 1 and $113.40 in Year 2. Therefore, for the average residential customer, the monthly bill under 1CP is $0.25 (25 cents) higher in Year 1 than under SWPA, and $0.24 (24 cents) higher in Year 2. While the Commission did not request similar information for industrial customers, logic and mathematics indicates that the impact on such customers' monthly bills would be much greater than 25 cents, inasmuch as the Company at the end of the test year had 1,211,761 residential customers, accounting for 15,001 million kWh in sales for the year then ended, but only 3,922 industrial customers at that time, accounting for 8,373 million kWh in sales over the same period. (See NC WARN Yates/Newton Exhibit 1)

The Commission also concludes that the Company should file annual cost of service studies based on both the 1CP and SWPA methodologies, and in its next general rate case filing the Company shall prepare cost of service studies based on both methodologies. The studies should be included in Item 45 of NCUC Form E-1 of the minimum filing requirements for a general rate case application, or in the corresponding section of any amended set of minimum filing requirements.

EVIDENCE IN SUPPORT OF FINDINGS OF FACT AND CONCLUSIONS NOS. 37-39

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

In its Application, DEP requests approval of its proposed Industrial Economic Recovery Rider (Rider IER), a five-year pilot experimental discount rider for industrial customers that state that they have a reasonable expectation to maintain historic employment levels. Company witness O'Sheasy provided direct testimony in support of the Company's proposed Rider IER. Witness O'Sheasy explained that Rider IER is intended to provide a temporary lower rate to industrial customers to assist them in retaining and increasing employment within DEP's service area. DEP's sales to industrial accounts peaked in 1997 and have declined nearly every year since resulting in 28% fewer kWh sales in 2011 than sold in 1997. Witness O'Sheasy testified that this decline of the state's manufacturing base has also been seen in unemployment statistics. Unemployment in the counties served by DEP has more than doubled since 1997, when it was 5%, and stood at an average of 11.2% at year-end 2011. Since 2002, nearly 500 MW of industrial load and over 35,000 jobs have been lost in DEP's service territory.

Witness O'Sheasy testified that the Company's proposed Rider IER offers a two-tier rate credit. The first block rate is applicable to the first 250,000 kWh of monthly usage. The second block rate is twice the first tier rate and is applicable to all usage in excess of 250,000 kWh. This design offers a discount to all eligible industrial customers and maximizes the benefit to large consumers that employ a significant number of people as well as adding increased benefits to those customers who grow their business.

Witness O'Sheasy also explained the eligibility requirements for Rider IER. Rider IER will be available to all industrial customers that (1) have a manufacturing or mining classification, (2) have a reasonable expectation to retain historic employment levels at the facility, and (3) request or receive an energy audit by a Certified Energy Manager within

12 months of requesting service under the rider. The proposed rider will reduce industrial revenues by nearly $31 million, or a 5.5% reduction to current rates. DEP seeks to recover the amount of this discount through a uniform rate increase of 0.084 cents per kWh to all customers, including the industrial class. Therefore, the net impact of the rider on participating industrial customers will be a 4.2% reduction in rates, while residential customers will realize a 0.8% increase in rates due to their share of the discount. The increase in rates for the average residential customer using 1,000 kWh per month will be approximately 84 cents per month, or about $10.08 per year.

Witness O'Sheasy explained that the Company believes that Rider IER will assist in attracting and retaining industrial businesses and jobs in North Carolina. The Company recognizes that the influence of electric rates is a major consideration in attracting and retaining industrial businesses and jobs. DEP believes that retaining and growing jobs is important to the citizens of the state of North Carolina and helps keep large customers in business.

CUCA witness O'Donnell testified in support of the Company's proposed Rider IER. Witness O'Donnell testified that "Rider IER is a good first step" for DEP to regain some of the industrial sales it has lost over the past 15 years. (T, Vol. 3, p. 227) Witness O'Donnell discussed a trend called "onshoring" where manufacturers are returning their operations to the United States in part because energy prices have become more competitive relative to other countries. Witness O'Donnell also urged the Commission to "put the rate increase from Rider IER in perspective." (Id.) Witness O'Donnell calculated that residential and commercial rates would increase by 8.1% if the Company's industrial sales completely erode. He concluded that it would be much less harmful to these customers to pay a 0.8% increase for five years than to pay a permanent 8.1% increase.

CIGFUR witness Phillips also testified in support of the Company's proposed Rider IER. Witness Phillips testified that a healthy industrial base is important to the economy of the state and that industrial sales in DEP's service territory have declined by 2.5 million MWh, or 19%, from 2002 to 2011. While industrial sales have declined at an alarming rate, residential and commercial sales are projected to increase. In light of these trends, witness Phillips testified that Rider IER is sound ratemaking policy and recommended that the Commission approve it.

The Public Staff and several other intervenors provided testimony in opposition to the Company's proposed Rider IER. Public Staff witness McLawhorn referred to Rider IER as a "load retention tariff" and argued that the Company did not perform the required analysis for Commission consideration of this tariff. (T, Vol. 4, pp. 247-53.) Witness McLawhorn stated that a load retention tariff typically provides a discounted rate to certain industrial or commercial customers in order to retain load in a utility's service area. He further stated that a properly-designed load retention rate provides no more of a discount than necessary to retain load and covers at least the marginal cost of serving the customers receiving the discount, plus a contribution to fixed costs. Thus, witness McLawhorn concluded that the Company should have provided an analysis showing that the discount provided by Rider IER would, in fact help retain load.

Witness McLawhorn stated that load retention tariffs in other states typically include the following kinds of provisions/requirements: affidavits confirming eligibility or need; service contracts; fixed terms; provisions ensuring that revenues exceed the incremental cost to serve; proof of financial distress; and penalties or repayment if the contract is violated or load is not retained. He noted that when designed based on appropriate analysis and implemented correctly, load retention rates can benefit all ratepayers while providing assistance to customers in need.

Witness McLawhorn further testified that in Docket No. E-100, Sub 73 the Commission adopted guidelines and filing requirements for economic development rates. Like Rider IER, these rates are targeted discounted rates designed to retain existing load or attract new load, which benefit all ratepayers by spreading fixed costs over more customers than would otherwise be the case. Generally, the guidelines and filing requirements for these rates require a utility (a) to demonstrate, among other things, that the rate is in the best interest of the utility's ratepayers and will comply with existing statutes and rules prohibiting unjust discrimination and undue preference, and (b) to provide a calculation of the revenue difference between the proposed and existing rate. Additionally, the guidelines require a marginal cost analysis demonstrating that the projected marginal revenues exceed the projected marginal costs. The Company has previously provided the necessary support and data for approval of economic development tariffs ED and ERD as required by Docket No. E-100, Sub 73. Witness McLawhorn argued that Rider IER is similar in purpose to these economic development riders, but the Company did not undertake or provide any supporting analysis for it.

Witness McLawhorn testified that the Public Staff has a number of concerns regarding Rider IER. He pointed out that the Company has not provided any support for the need for, or the amount of, the discount. He stated that according to responses to Public Staff data requests the Company has not conducted any studies and does not have any data to indicate that the Rider would be effective in retaining customers, and cannot show that the discount is set at the lowest amount necessary to retain jobs and sales without providing a windfall to industrial customers. Further, the Company has not conducted any studies to demonstrate that the rates resulting from Rider IER exceed the marginal cost to serve those customers. Rather, when asked how the Company determined that the amount of the discount is appropriate, the Company stated that it had conferred with industrial customers and its Account Management staff. Thus, Rider IER was not designed based on a study and analysis of the costs and benefits, but by consultation with only the customers who would benefit from the discount.

Witness McLawhorn also pointed out that while Rider IER requires participating customers to undergo an energy audit of their facility, there is no requirement that the customers implement any of the recommendations of the audit. Further, he noted that there is no provision for forfeiture of any portion of the rate discount if none of the recommendations is implemented. Witness McLawhorn testified that Rider IER also requires a participating customer to "state a reasonable expectation to maintain current employment levels." Yet Progress Energy Carolinas has indicated that it has no plans to undertake any verification of such statements, and there is no provision in the Rider for forfeiture of any portion of the rate discount if a customer fails to maintain employment levels. Under these circumstances, witness McLawhorn concluded that the requirements are essentially meaningless.

Witness McLawhorn stated that because Rider IER is open to all industrial customers with a SIC Code qualification, there will be free riders. Not all customers classified as industrial are facing financial hardship, and for some of those who are the cost of electricity is not the primary reason. Yet the proposal does not include a provision to assess the true economic circumstances of customers who apply for the Rider and prevent or reduce free ridership.

Witness McLawhorn also noted that while the Company has proposed Rider IER as a pilot intended to help prevent further loss of industrial load, the Company has not indicated what criteria would indicate that the pilot is a success, or how the Company would measure the effectiveness of the pilot. He emphasized that there is no evidence that indicates that there is a high likelihood that Rider IER will be successful in preventing loss of load.

Witness McLawhorn stated that the Public Staff is not opposed to load retention riders, generally, but it is opposed to poorly designed load retention riders such as the IER. He stated that if the Company came back to the Commission with a more properly designed rider, i.e., one that had provisions to prevent free ridership and to ensure compliance with the customers' commitments to retain load and employment, along with a marginal cost analysis of the impact on other ratepayers on the system as a whole, the Public Staff would look more favorably on the proposal.

According to the Public Staff, even assuming that Rider IER would encourage the retention of industrial load, Rider IER is unreasonably discriminatory. The North Carolina Supreme Court has held that G.S. 62-140(a) requires that a substantial difference in service or conditions must exist to justify a difference in rates. State ex rel. Utilities Commission v. Public Staff, 323 N.C. 481, 374 S.E.2d 361 (1988); State ex rel. Utilities Commission v. N.C. Textile Manufacturers Association, Inc., 313 N.C. 215, 328 S.E.2d 264 (1985). As written, Rider IER would discriminate between similarly situated customers in a way that is unreasonable. The situation presented by Commercial Group witnesses Chriss and Rosa regarding the two bakeries is illustrative. Under the Company's proposal, because they fall under different classifications under the SIC, a stand-alone bakery would be eligible for Rider IER, but a bakery within a Food Lion store would not. In addition, the Food Lion would have to pay higher rates to subsidize the rate discount for the stand-alone bakery. The Public Staff sees no reason why two businesses with similar characteristics and even within the same rate class, but differentiated only by an industrial SIC code, should not both be eligible for the proposed IER.

Kroger witness Higgins also recommended that the Commission reject DEP's proposed Rider IER. Witness Higgins argued that Rider IER is a discriminatory rate structure, similar to rate schedules OPT-I, OPT-G, and OPT-H that the Commission ordered to be phased out in Duke Energy Carolinas' recent rate case in Docket No. E-7, Sub 989. According to witness Higgins, Rider IER would establish the same Standard Industrial Classification Manual (SIC) code-based discrimination that the Commission phased out in Duke's service territory. Alternatively, witness Higgins contended that if the proposed Rider IER is approved, it would be more reasonable for DEP to fund the rider by accepting a lower rate of return for industrial customers rather than increasing its requested rate of return for serving other customers. Witness Higgins proposed that DEP should accept a 9.81% ROE for industrial customers served under Rider IER, rather than require its remaining customers to subsidize the discount.

Commercial Group witnesses Chriss and Rosa also testified in opposition to the Company's proposed Rider IER. Like witness Higgins, witnesses Chriss and Rosa testified that customers paying higher rates than others based on SIC codes is an unreasonable and unfair way to set rates and could potentially affect the competitiveness of non-participating businesses. They noted that non-participating ratepayers would be charged $31 million a year for the five-year program ($150 million total) in direct subsidies to participating industrial customers. Witnesses Chriss and Rosa also referenced the Commission's decision in Duke Energy Carolinas' last rate case, Docket No. E-7, Sub 989, stating that Rider IER is discriminatory in the same way that the Commission found rate schedule OPT-I to be discriminatory in that case.

Department of Defense witness Prisco testified that eligibility for DEP's proposed Rider IER should be expanded to include large federal government facilities. Witness Prisco testified that several large federal government facilities are located in DEP's service area, including Fort Bragg, Seymour Johnson Air Force Base, Camp Lejeune, the Marine Corps Air Station Cherry Point, and the Military Ocean Terminal at Sunny Point. The DoD provides over 100,000 military and civilian direct hires in DEP's service area and an equivalent amount of indirect/ancillary hires. According to witness Prisco, the policy reasons for Rider IER, including job growth and retention, support extending the discount to the DoD as well as industrial customers.

UMS and LCFWSA witness Coughlan also recommended broadening eligibility for Rider IER so that it is available not only to industrial customers, but to any customer currently on DEP's MGS, SGS-TOU, LGS, LGS-TOU, or LGS-RTP rate schedules. Witness Coughlan testified that Rider IER should strive to help all businesses retain and increase employment, not just manufacturers.

Company witnesses Wright, O'Sheasy, and Newton filed rebuttal testimony responding to the concerns raised by other witnesses related to the Company's proposed Rider IER. Witness Wright, a former Commissioner, testified extensively about the significant negative economic impacts to a region that result from the loss of large industrial customers. Witness Wright conducted a study which found that for every lost employee of a departing industrial facility: (a) there are from one to three additional jobs lost in the region; (b) there is a region-wide decrease of approximately $500,000 per year in additional economic output; and (c) there is a region-wide decrease of $200,000 to $350,000 in total employee earnings. Witness Wright's study demonstrated a trend called the economic "multiplier effect" whereby the closure or relocation of just one large industrial facility in DEP's service area results in lost jobs, and with these job losses come the related lost wages, lost economic output, and lost tax revenues. Witness Wright explained that Rider IER is specifically designed to promote job retention and avoid these disastrous economic effects.

Witness Wright further explained that when an industrial customer in the Company's service area closes or relocates, it not only has the negative economic impact of lost jobs, it also has negative rate consequences for the customers remaining on DEP's system. Witness Wright testified that if DEP's industrial customers continue to leave, residential and commercial customers' rates will increase. He explained that industrial customers subscribing to Rider IER would be paying what is termed their variable costs plus making a contribution to the recovery of fixed costs. In ratemaking, it has long been held that so long as a customer who would otherwise leave the system stays on the utility's system and pays its variable cost plus pays a contribution to the recovery of the utility's fixed costs, then all the other utility customers will be "better off" in terms of paying reduced rates. Witness Wright explained this means that, all other things being equal, the remaining customers' rates would be higher if the Rider IER customers leave the

Company's system. The loss of industrial customers means that fixed costs that were previously borne by industrial customers shift to other rate classes. Witness Wright stated that the loss of a larger industrial customer or customers could theoretically result in residential and other customers experiencing even larger rate increases ranging from 1% to 3%. He noted that this is not an inconsequential impact in light of the fact that the Company has lost 28% of its industrial load between 1997 and 2011.

Witness Wright also responded to the other witnesses' argument that Rider IER is discriminatory. He testified that under G.S. 62-140(a), the standard is that a rate must not be "unreasonably" discriminatory. He pointed out that for almost two decades the Commission has allowed Duke Energy Carolinas and DEP to offer new and expanding large industrial customers special rate discounts in an effort to support economic growth. Witness Wright reasoned that if these current tariffs are not unreasonably discriminatory, Rider IER should likewise not be considered unreasonably discriminatory. He also stated that Rider IER is not unreasonably discriminatory because, over time, not having Rider IER results in lost industries, lost jobs, and higher electric rates to the remaining customers.

In addition, witness Wright testified that several other states, including Florida, Georgia, some Texas jurisdictions, California, New York and Massachusetts, currently have job retention tariffs similar to the Company's proposed Rider IER. A recent (2012) survey conducted for witness Wright's Economic Report found that the majority of the approximately 20 states and jurisdictions that responded had regulated utilities that offered some form of a retention tariff, an economic development tariff, or both. Consequently, by offering Rider IER, witness Wright believes that the Company and the Commission would, in effect, be keeping pace with some of the tariffs that are currently being offered by other, including neighboring, states.

According to DEP in its Brief, limiting the availability of Rider IER to the industrial class in no way runs afoul of North Carolina law prohibiting unjust discrimination and undue preference. G.S. 62-140(a) provides: "No public utility shall, as to rates or services, make or grant any unreasonable preference or advantage to any person or subject any person to any unreasonable prejudice or disadvantage. No public utility shall establish or maintain any unreasonable difference as to rates or services either as between localities or as between classes of service." In other words, the statute plainly prohibits (1) unreasonable preferences, (2) unreasonable advantages, (3) unreasonable prejudices, (4) unreasonable disadvantages and (5) unreasonable differences. <u>State ex rel. Utils. Comm 'n v. Bird Oil Co</u>., 302 N.C. 14, 22, 273 S.E.2d 232, 240 (1980) (holding that a dedicated rate structure providing for 15% lower rates on shipments of certain products for large shippers did not violate the prohibition on discriminatory rates). Neither the statute nor the case law, however, prohibits any preferences, advantages, prejudices, disadvantages, differences or discrimination in setting rates. <u>Id</u>. Therefore, the long-established question of law with respect to rate differentials is not whether the differential is merely discriminatory or preferential; the question is whether the differential is an unreasonable or unjust discrimination. <u>Id</u>.

Accordingly, the charging of different rates for services rendered does not per se violate G.S. 62-140. <u>State ex rel. Utils. Comm'n v. Nello L Teer Co</u>., 266 N.C. 366, 376, 146 S.E.2d 511, 521 (1966). However, classifications of customers and differences in rates must be based on reasonable differences in conditions, and the variance in charges must bear a reasonable proportion to the variance in conditions. State ex rel. Utils. Comm 'n v. Carolina Util. Customers Ass'n, 348 N.C. 452, 468, 500 S.E.2d 693, 709 (1998). Any matter that presents a substantial difference as a ground for distinction between customers or the rates charged is a material factor in the determination of rates. Nello L. Teer, 266 N.C. at 376, 146 S.E.2d at 521. Indeed, the Supreme Court has held that even if cost of service evidence alone might suggest that adopted rates are unreasonably discriminatory, where non-cost factors justify differing rates for individual customer classes, the rates are not unreasonably discriminatory. See State ex rel. Utils. Comm'n v. Carolina Util. Customers Ass'n. Inc., 323 N.C. 238, 372 S.E.2d 692 (1988). As former Commissioner Wright testified, cost is a guidance, but it is seldom the only thing a commission considers. Rather, a commission must weigh many factors. Accordingly, it is entirely permissible for the Commission to weigh in its deliberations many relevant factors related both to costs and to other issues such as economic considerations. Moreover, the economic circumstances facing industrial customers - namely the substantial decline in industrial sales as well as the multiplier effect described by witness Wright - are truly unique to the industrial class and warrant differing rates for industrial customers as opposed to other customer classes.

Witness O’Sheasy responded to the other witnesses’ testimony that Rider IER should be expanded to customer classes other than just industrials. Witness O’Sheasy testified that the primary driver for offering rate assistance to the industrial class is the closure of North Carolina manufacturing facilities and the resulting steady decline in sales. In contrast, during this same period, sales to military bases increased by 27% while commercial sales increased by 40%. Therefore, witness O’Sheasy testified that DEP does not believe that circumstances warrant expanding Rider IER to other groups at this time, especially since expanding Rider IER past the Company’s proposal would increase the burden upon other rate classes. Witness O’Sheasy explained that limiting the availability of the rider allows the Company to assist the group of customers most in need of assistance while also minimizing the impact of the rider recovery on non-participants. Company witness Newton further testified that through Rider IER “[W]e are trying to reach out to assist that customer class that is clearly in trouble today, which also impacts the rest of the customer classes.” (T, Vol. 1, p. 139.) He also stated that “We care about and respect and appreciate every one of our customers, but Dr. Wright has done a study that shows that industrial customer activity, positive and negative, has a unique multiplier effect on the rest of the economy, so that is what we’re trying to address with Rider IER.” (Id., p. 140.)

The Company witnesses also addressed Public Staff witness McLawhorn’s concerns regarding free ridership and policing participation in the rider. Witness O’Sheasy explained, there is no “silver bullet” in rate design, and free riders are part of the nature of average ratemaking. He explained that attempts to screen out free riders, such as requiring participants to demonstrate financial need, can be counterproductive. He stated that because customers are often reluctant to release financial information, this type of screen would discourage participation in the rider and frustrate the Company’s objective of retaining industrial jobs in North Carolina. Witness Wright also testified that “from a policy perspective, I would recommend that this rider go forward simply because the economic impacts are so great, and the loss of industrial jobs for the last fifteen years has been quite large, and the state’s unemployment is high. All those considerations, to me, weigh far more in favor of this tariff than consideration of a free rider.” (T, Vol. 8, pp. 27-28.)

Finally, according to DEP, shareholders should not be required to bear the costs of the temporary discount offered under Rider IER. It makes sense for customers to bear the de minimus cost of Rider IER - approximately 84 cents per month for the average 1,000 kWh per month residential customer - since it benefits all rate classes and prevents rates from being increased due to the loss of industrial customers. The rider is a long-term strategy to try to improve the well-being of the entire community, including other customer classes, residential and commercial. In addition, as witness Newton explained, the Company has already paid a cost in terms of settling this case and agreeing to a substantial reduction in its revenue requirement ($90 million of which resulted from the Company's agreement to reduce its requested ROE from 11.25% to 10.2% and equity ratio from 55% to 53%). Moreover, the Company's shareholders already support a number of job retention and retraining programs in addition to giving to the local community. In fact, as part of the Stipulation, the Company has agreed to convert $20 million of a regulatory liability for the benefit of the Company's North Carolina retail customers to be allocated among (a) local agencies and organizations for programs that provide assistance to low-income customers and (b) programs that provide training that improves worker access to jobs and increases the quality of the workforce. As witness Newton explained, "we're trying to do everything we can to make sure that North Carolina is healthy, but we can't do everything. We don't have unlimited resources at any level." (T, Vol. 8, p. 121.)

In its Brief, DoD notes that it is not eligible to receive the benefits of Rider IER as it is currently proposed by DEP, but does, however, currently face severe budget cuts due to sequestration and future significant budget reductions, as required by the Budget Control Act of 2011. While North Carolina benefited from previous base realignment and closures within DoD, if current and future economic conditions within North Carolina make it more cost effective for DoD to shift operations to other states, North Carolina may see reductions in DoD's presence and investment.

DoD states that it is one of North Carolina's largest employers and that the majority of DoD's employees work in DEP's service territory. Further, DoD states that the business needs of its North Carolina installations also support DEP's commercial and industrial customers, as well as providing training for employees. Thus, DoD should be allowed to participate in and benefit from Rider IER. In addition, DoD contends that basing IER availability solely on SIC codes renders IER discriminatory, in violation of G.S. 62-140(a). DEP attempts to justify the SIC criteria by pointing to the decline in industrial usage and jobs from 1997 through 2008, yet provides no evidence that the decline is due to electric rates. DoD also notes that DEP has experienced a gain in industrial customers since 2007, without the need for IER.

In addition, DoD contends that the two-tiered energy usage feature of IER makes an unsupported assumption that the largest energy users are the largest employers. Further, it dilutes the benefits to the smaller industrial class energy users. DoD recommends that Rider IER be redesigned to benefit large employers, whether those employers are large energy users or not. Finally, DoD asserts that including it in Rider IER would not weaken the benefit available to other participants. If DoD is not included in Rider IER, then DoD submits that the Rider should be rejected by the Commission.

In its Brief, NC WARN states that it is an open question whether the Commission has the statutory authority to approve a job retention program, and in particular, a program that benefits one customer class at the expense of all other classes. Using $155 million of utility customer funds, rather than taxpayer funds, for a jobs program may be a policy decision which the General Assembly would want to debate, as opposed to an initiative undertaken by DEP and authorized by the Commission.

Citing N.C. Textile Mfrs. Ass'n, NC WARN asserts that Rider IER is discriminatory and fundamentally flawed because nonindustrial customers would be required to pay for services without receiving any benefits. It further notes that there was no evidence as to the number of jobs the program would retain, the number of "free riders" that would benefit from the program, or any criteria to identify which industrial customers need additional assistance. According to NC WARN, the main justification for the IER Rider is the merger settlement agreements between DEP and the industrial customer groups.

In its Brief, CIGFUR cites numerous statistics, including DEP's loss of industrial load and the corresponding gain in commercial and residential customers. CIGFUR submits that Rider IER is a modest and reasonable effort to assist industrial customers. CIGFUR also contends that the criticisms of Rider IER are not valid. For example, although Public Staff witness McLawhorn characterizes Rider IER as a load retention rider, it is a job retention rider. Further, the fact that it stems from merger settlement agreements between DEP and the industrial groups should not be detrimental because settlements are encouraged and are often in the public interest. Finally, CIGFUR notes that DEP, the industrial groups and the Public Staff can work together to resolve any technical issues regarding the operation of IER.

In its Brief, CUCA discusses the decline in industrial sales and jobs in DEP's service territory and the lower industrial rates of DEP's neighboring utilities, as well as DEP's lower industrial rates in South Carolina. Further, CUCA asserts that Rider IER is not discriminatory to the commercial class because it targets the industrial class as being the group needing assistance due to declining sales. Further, spreading the IER rate reductions to all commercial and industrial customers would substantially lessen and, thus, weaken the benefits to industrial customers. In addition, the preservation of industrial customers will help avoid the increases in residential and commercial rates that will result because of additional losses of industrial customers. Finally, CUCA responds as follows to several criticisms of Rider IER that are levied by the Public Staff.

1. Rider IER is a customer and job retention rider, not a load retention rider.

2. As a customer and job retention rider, IER is not required to meet the criteria established in Docket No. E-100, Sub 73. Nonetheless, it satisfies most, if not all, of those criteria.

3. IER narrow focus targets the customers most in need of rate relief.

4. No supporting studies are needed to show the need for IER because the facts are established by the evidence.

5. A requirement that customers demonstrate a financial need for IER would create an unnecessary barrier to participation.

6. There is not a need to require verification of continued employment levels. This can be effectively monitored by DEP's account representatives and attention to customer usage.

7. The Public Staff presented no evidence that it will be difficult for industrial customers to transition back to undiscounted rates at the conclusion of the IER pilot program.

In conclusion, CUCA submits that Rider IER, although perhaps not perfect, is the best and most reasonable course of action to address the economic stress that continues to impact DEP's industrial customers.

In its Brief, Kroger submits that Rider IER is contrary to the Commission's decision regarding OPT rates in Duke's 2011 rate case. In that case, the Commission ordered Duke to begin re-combining several OPT rate schedules. Kroger asserts that IER would create the same type of discrimination based on SIC codes that the Commission is eliminating in Duke's OPT rates. Kroger also disagrees with DEP's attempt to distinguish IER from OPT as a temporary rider rather than a base rate tariff. Kroger states that G.S. 62-131 requires all customer charges, whether rates or riders, to be just and reasonable. Further, Kroger notes that the Rider IER requirement for an energy audit is not a distinguishing factor because there is no condition that industrial customers make any changes based on the audit results. Finally, Kroger notes that DEP has not shown any nexus between receipt of the Rider IER rate discount and retention of employees.

In its Brief, NCLM states that any rate discount for economic development purposes should also be available to municipal and public authority customers. NCLM maintains that the Commission should consider the direct and indirect economic development benefits provided by DEP's municipal customers, citing examples such as the recruitment of industry and other employers. Further, NCLM asserts that it would not be unreasonably discriminatory to apply Rider IER to municipal customers and public authorities, noting that as DEP points out the operative word in G.S. 62-140 is that rates must not be "unreasonably" discriminatory. NCLM also notes that municipalities and public authorities can be easily identified for purposes of eligibility for the Rider by reference to statutes, similar to the criteria for identifying eligible industrial customers by reference to SIC codes.

Commercial Group asserts in its Brief that Rider IER unjustly discriminates among customers based solely on a customer's SIC code, in violation of G.S. 62-140, a type of discrimination the Commission rejected in Duke's rate case by ordering Duke to modify its OPT rates. The "unreasonable difference" that would be created by Rider IER is more apparent due to the fact that 95% of the industrial customers eligible for the IER are members of the SGS and MGS rate classes. Further, this demonstrates that Rider IER is not designed to achieve its stated result because 95% of the eligible customers are not large industrial customers. In addition, the Rider IER costs would create further inequity by increasing MGS rates, which are already above cost. Another deficiency in Rider IER is the absence of any real compliance requirements or accountability of those customers receiving the discount.

The question of whether the Commission should approve Rider IER is largely a public policy issue requiring the Commission to balance the costs and benefits to DEP's ratepayers and arrive at a decision that promotes the public interest. The Commission is concerned about the loss of industrial jobs in DEP's service area and the detrimental effect on DEP and its customers. The Commission accepts the Company's explanation that proposed Rider IER is an effort to retain industrial jobs in North Carolina and the evidence concerning the multiplier effect that industrial jobs have on the economy. Further, the Commission finds that industrial customers' sales have been declining, while residential and commercial sales are projected to increase. On the other hand, the Commission is concerned about the adverse impact that Rider IER would have on residential and commercial ratepayers. For example, although a 0.8% increase in residential rates appears small, it would be on top of the 7.5% increase approved by this Order. Further, the recent and persistent high unemployment in DEP's service area causes the Commission concern about shifting a portion of the rate increase from industrial customers to other customer classes. The Commission concludes that Rider IER does not strike a fair balance between the costs and benefits to DEP's ratepayers and, thus, is not in the public interest at this time.

In addition, based on the evidence in this case the Commission is not persuaded that Rider IER would result in just and reasonable rates, as required by G.S. 62-130. There is no substantial evidence that DEP's industrial rates were a significant factor in any industrial customer having reduced the level of its operations or departed North Carolina, or that Rider IER would in fact cause industrial customers to maintain current employment levels or operation levels in North Carolina. Thus, the Commission is unable to conclude that Rider IER's primary purpose for shifting a portion of the rate increase from industrial customers to commercial and residential customers will be achieved.

Further, the eligibility requirements for proposed Rider IER are inadequate and are likely to result in an unacceptable level of free ridership. It is true that some free ridership may occur when any special rate is offered. However, Rider IER is devoid of any meaningful qualifications and requirements to verify that a particular customer or group of like customers is in need of an electric rate discount or will use that discount to preserve jobs in North Carolina. Such eligibility requirements would help assure that the discount rate serves its purpose and also help prevent free riders. Also, monitoring and verification measures for the proposed rider are inadequate. The requirements that a customer must "state a reasonable expectation to maintain current employment levels" and receive an energy audit are insufficient. A customer could state that it intends to maintain employment levels, but nevertheless reduce employment, then reapply and again receive the benefits of the Rider. Moreover, DEP has no plans to actively monitor or sample employment levels in any structured or consistent manner. Further, there are no guidelines for accountability of customers, such as a provision for refunding the discount should any of the requirements not be met. The Commission recognizes that a load retention rate could be overburdened with administrative requirements, but the Company's proposed Rider IER lacks any effective or meaningful way to verify that customers are adhering to the eligibility requirements.

For the foregoing reasons, the Commission finds and concludes that the evidence is not sufficient to show that proposed Rider IER would result in just and reasonable rates. However, the Commission recognizes that a job retention tariff may be in the public interest under certain circumstances. Thus, by separate order in Docket No. E-100, Sub 73 the Commission will request comments regarding specific guidelines that should be adopted for the approval of job retention tariffs. In particular, the Commission would be assisted by comments regarding appropriate criteria or benchmarks that should be employed for determining whether a job retention rider is effective, given that there are numerous factors that can cause a business to open or close, as well as cause a business to lose, retain or increase the number of employees at any given business location, including an overall improvement in the economy. Once those guidelines are finalized, the Company may choose to file a job retention tariff in accordance with those guidelines.

EVIDENCE IN SUPPORT OF FINDING OF FACT AND CONCLUSION NO. 40

The evidence supporting this finding of fact and conclusion is contained in the the Application, the testimony of witnesses Bateman, Phillips, O'Donnell, Chriss and Rosa, and in the Stipulation.

Witness Bateman testified that although DEP believes that its DSDR program meets the criteria for recovery in the DSM/EE rider, as the project moves out of the construction phase it will become more complex and prone to error for DEP to properly identify costs that are incremental due to DSDR. Thus, in order to ensure proper accounting, DEP proposed to move DSDR costs out of its DSM/EE rider and into base rates, except those DSDR costs that had been deferred.

CIGFUR II witness Phillips, CUCA witness O'Donnell, and Commercial Group witnesses Chriss and Rosa opposed DEP's proposal regarding DSDR costs.

In the Amendment to the Stipulation filed on March 14, 2013, DEP withdrew its proposal to move most DSDR costs into base rates, and DEP and the Public Staff agreed to work together to address the "administrative concerns" that prompted DEP's original proposal.

All parties to this proceeding at this time agree that all DSDR costs should remain in DEP's DSM/EE rider. Therefore, the Commission will not act on the original DSDR proposal at this time, except to require DEP to file additional information in future proceedings, as discussed below.

In its next DSM/EE rider proceeding, DEP shall explain whether and why it is appropriate for the Company to receive a net lost revenue (NLR) incentive for DSDR as originally contemplated by the Commission's orders in Docket No. E-2, Subs 926 and 931. In those proceedings, the Commission granted the Company cost recovery for DSDR. By designating DSDR as an EE program, the Commission allowed the Company to recover its incremental expenditures immediately via the DSM/EE rider, rather than waiting for a general rate case. In addition, the Commission approved the rider mechanism that DEP had negotiated with the Public Staff. That mechanism includes favorable treatment for DSDR costs. In particular, the Company was allowed to begin recovering its incremental capital and O&M costs for DSDR in late 2008, even though the program would not be activated until 2012. The Company also was allowed to begin earning a return on DSDR capital costs, again several years before the program would be available to serve customers. Further, DEP was allowed to amortize its DSDR O&M costs over ten years while earning a carrying charge on the unrecovered balance. Finally, the cost recovery mechanism allows DEP to recover a NLR incentive for DSDR for three years.

The Commission now questions whether the NLR incentive is appropriate given that DEP has failed to fully complete DSDR in time to serve customers during its 2013 summer season.

On November 20, 2012, DEP filed its DSDR Annual Report informing the Commission that DSDR was anticipated to go operational in December 2012, but that “the realization of the total peak demand reduction capability of the DSDR program has been extended into 2014.” The Company also stated that DSDR’s total peak reduction capability would be 236 MW, 11 MW less than DEP originally stated. In its March 14, 2013 response to the Commission’s Pre-Hearing Order Requiring Verified Responses, DEP stated that DSDR was currently capable of providing 105 MW of demand reduction. Based on this information it appears that DEP is entering its 2013 peak season with 142 MW less demand reduction capability and on-peak energy conservation than it had committed to provide via DSDR. Therefore, the Commission will require DEP to explain in its upcoming DSM/EE rider application whether and why it is still appropriate for the Company to recover from customers the NLR incentive. The Commission encourages the Public Staff to comment on this issue as well.

Similarly, because DSDR will not be fully available to provide peak demand reduction and on-peak energy during 2013, the Commission will require DEP to provide additional documentation in its 2014 fuel rider application. Specifically, the Commission will require DEP to: (1) demonstrate the incremental costs that it incurred to supply customers with capacity and energy during 2013 to the extent DSDR is not fully available; and (2) explain whether and why the Company should be entitled to recover those incremental costs from its retail customers via the fuel rider. DEP shall develop this documentation for each month that DSDR’s full capability is not available to serve customers and include the information in its fuel rider applications.

Finally, the Commission will require DEP to include in its next DSM/EE rider application a thorough description of the size and scope of the DSDR accounting issues that prompted its initial proposal in this case, and the options for addressing those accounting issues.

IT IS, THEREFORE, ORDERED as follows:

1. That the Stipulation filed by Duke Energy Progress and the Public Staff is hereby approved in its entirety;

2. That Duke Energy Progress shall be allowed to increase its rates and charges effective for service rendered as of June 1, 2013, so as to produce a two-step increase in gross annual revenue for its North Carolina retail operations of $147,384,000 in the first year and $31,328,000 in the second year, totaling $178,712,000 (as measured from present rates, on an annualized basis), based upon the adjusted test year level of operations, as set forth in this Order;

3. That the approved base fuel and fuel-related cost factors are as follows (amounts are cents per kWh, excluding gross receipts tax and regulatory fee): 3.030 for residential customers; 3.020 for SGS customers; 2.935 for MGS customers; 2.969 for LGS customers; and 3.692 for lighting customers;

4. That the two-step increase in rates approved in this proceeding shall be effectuated by the implementation of a one-year decrement rider, beginning on June 1, 2013, to

delay the inclusion of Sutton CWIP, resulting in a $31,328,000 reduction in the stipulated revenue increase for the period of one year from the effective date of this Order;

5. That the Company shall implement an increment rider, effective June 1, 2013, and expiring at the earlier of (a) November 30, 2014, or (b) the Coal Inventory Rider Termination Date as defined in this Order, to allow the Company to recover the additional costs of carrying coal inventory in excess of a 40-day supply (priced at $91.623 per ton);

6. That beginning with the effective date of the rates set in this proceeding, the North Carolina retail fuel line loss differential shall be recovered as part of the fuel and fuel-related cost factor, and not as part of the non-fuel component of base rates;

7. That certain fuel related costs pursuant to G.S. 62-133.2(a2)(1) and (2) identified in subdivisions (4), (5), and (6) of subsection (a1) will be allocated among customer classes as set forth in paragraph 3.C. of the Stipulation;

8. That the Company may use levelization accounting for nuclear refueling costs effective January 1, 2013;

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

10. That the Company shall increase its Basic Customer Charge for Schedule RES to $11.50 per month and the Basic Customer Charges for Schedules R-TOUD, R-TOUE, and R-TOU to $14.60 per month;

11. That the Company shall close Schedule R-TOUD to new customers, except for those who will be served under Rider NM, Net Metering;

12. That the Company shall not adjust the on-peak hours in the medium and large general service TOU rate schedules (SGS-TOU and LGS-TOU) at this time;

13. That Duke Energy Progress shall complete a study of its TOU hours for general service customer classes to ensure that TOU hours appropriately reflect cost to serve and the actual conditions of the Company's utility system, including an evaluation of the current TOU rate structures. In addition, the Company shall include in the study an examination of the specific issues related to water and sewer treatment facilities raised by NCLM, and the issue regarding constant load CATV power supply equipment. Further, the study shall include the details of all efforts made by Duke Energy Progress to inform customers about the availability of TOU rates and to encourage its customers' use of such rates. The Company shall report the results of this study in its next general rate case or within two years from the date of this Order, whichever comes first;

14. That the Company shall implement its proposed minimum charge for distribution facilities for rate schedules SGS-TOU, CH-TOUE, GS-TES, APH-TES, CSE, and CSG;

15. That within 60 days of this Order, the Company shall evaluate the service of each customer impacted by the minimum bill provisions for each rate schedule and determine whether

the customer would be better served under another rate schedule. The Company shall make a proactive effort to ensure that any customer impacted by the minimum bill provisions is afforded the opportunity to migrate to the most advantageous rate schedule for electric service;

16. That the Company shall implement proposed Riders SS and NFS to provide supplementary and standby service;

17. That the Company shall cancel existing Riders 66 and SSSW, with all existing customers being migrated to Rider SS or NFS as appropriate, and the Company's Rider 57 shall remain closed to new customers;

18. That the base revenue increase of $178,712,000 should be assigned to the customer classes as proposed by the Company to achieve the rates of return identified in Corrected Bateman Rebuttal Exhibit 2, with the rates and charges set to achieve the Company's recommended customer class rates of return as closely as possible;

19. That the revenue impact of the Sutton CWIP rider decrement shall be assigned using the production plant allocator and the revenue impact of the Coal Inventory rider increment shall be assigned using the class adjusted energy sales. The Company's compliance filing should clearly show the calculations of base revenues, the revenue increase, the revenues associated with the Sutton CWIP and Coal Inventory riders, and the impacts of each in the first year of implementation and in subsequent years;

20. That as soon as practicable after the issuance of this Order, Duke Energy Progress shall file for Commission approval five copies of all rate schedules designed to comply with this Order, accompanied by calculations showing the revenues that will be produced by the rates for each schedule. This filing shall include a schedule comparing the revenue that was produced by the filed schedules during the test period with the revenue that will be produced under the proposed settlement schedules, and a schedule illustrating the rates of return by class based on the revenues produced by the rates for each schedule;

21. That within 60 days of this Order, the Company shall consult with the Public Staff and submit for the Commission's review and approval a specific proposal for distribution of $20 million in funds for the benefit of the Company's North Carolina retail ratepayers to be allocated among (1) local agencies and organizations for programs that provide assistance to North Carolina retail low-income customers of Duke Energy Progress for uses such as those identified in Docket No. E-7, Sub 989, and (2) the North Carolina Community Foundation for programs that provide training that improve worker access to jobs and increase the quality of the workforce;

22. That as soon as practicable after the issuance of this Order, Duke Energy Progress and the Public Staff shall submit a proposed customer notice to the Commission for review and approval, and upon approval of the notice by the Commission the Company shall give appropriate notice of the approved rate increase by mailing the notice to each of its North Carolina retail customers during the billing cycle following the effective date of the new rates; and

23. That the Company shall file annual cost of service studies based on both the 1CP and SWPA methodologies.

24. That Duke Energy Progress shall provide the DSDR information specified in this Order as part of the Company's next DSM/EE rider and fuel rider applications.

ISSUED BY ORDER OF THE COMMISSION.
This the 30th day of May, 2013.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

Bh053013.02

Chairman Edward S. Finley, Jr., dissents in part.

DOCKET NO. E-2, SUB 1023

Chairman Edward S. Finley, Jr., dissenting in part:

The Commission should approve the experimental Industrial Economic Recovery rider (Rider IER) as a matter of sound ratemaking policy to address the undisputed decline in industrial sales in DEP's North Carolina service area. At the hearing, parties supporting Rider IER provided undisputed and compelling evidence regarding the State's historic loss of industry and drastic rise in unemployment. This evidence alone is sufficient to justify implementation of the temporary, experimental Rider IER within the bounds of just and reasonable ratemaking. The specific objective of this pilot program is an attempt to stem the further loss of industry, industrial production and industrial jobs from the DEP North Carolina service area. Commissions in other states have approved such incentive rates to promote a specific economic or social objective as long as the rates were above the utilities' marginal or avoided costs of serving such customers and thereby contributing to the fixed costs.[1] Thus, the Commission should approve Rider IER as being in the public interest.

Industrial customers as a class, for rate design purposes, have a number of distinctive characteristics. First, the industrial class has a high load factor. Industrial facilities operate many hours of the year other than at peak load hours. Therefore, the utility's fixed costs, many of which are incurred to meet the peak, are recovered from the industrial customers in off-peak hours, such as at night, when other classes place limited demand on the system. An electric utility system without a substantial industrial class but with a load profile consisting of many low-load factor consumers requires these non-industrials to pick up a much higher percentage of fixed costs.

Secondly, as a class of non-residential business customers, electric energy expense makes up a high percentage of the costs of doing business. While not the sole determinative factor as to

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[1] Charles F. Phillips, Jr., *The Regulation of Public Utilities* (Public Utilities Reports, Inc., 1993), 469.

whether a prototypical industrial customer is profitable or not, electric utility expenses for customers in this class is in fact a major factor determining profitability.

Thirdly, the industrial class, as business enterprises that exist only to provide profit to owners and as enterprises always looking to find locations where costs can be minimized, has the greatest potential to locate operations where costs are favorable.

DEP's industrial rates have been measurably higher than those of neighboring electric utilities and even higher than its own industrial rates in South Carolina. Assuming other major costs such as labor are not markedly different, these higher electric rates deter industrial enterprises from remaining in or relocating to DEP's North Carolina service area or in operating at full capacity.

DEP, along with other parties CUCA and CIGFUR, introduced stark and grim statistics at the hearing regarding the loss of industry from DEP's North Carolina service area. DEP's industrial sales have decreased 28% from 1997 to 2011, and the average unemployment in North Carolina has increased from 5.0% to 11.2% during the same time period. The number of manufacturing jobs lost over the last ten years is 200,000. Commercial, military and residential customers are not in the same position. Between 1997 and 2011, the number of commercial customers increased by 13% and is expected to increase another 28% over the next 16 years. DEP's residential sales increased 17% between 2002 and 2011 and DEP's military sales increased 29% during the same time period.

Furthermore, DEP indicated that DEP's industrial rates were already, prior to the rate increase proposal, higher than any of their adjoining neighbors in Virginia, North Carolina and South Carolina. DEP and CUCA produced evidence that a 5% loss of DEP's LSG load would result in a 0.40% increase in residential electric rates and that a total loss of industrial sales would increase rates for all other customers by 8%.[1] Lastly, DEP showed that industrials over a 2-3 year period and beyond have the ability to alter their electricity consumption by as much as 30% to 40% in response to a 10% increase in electricity rates. This elasticity of industrial customers is significant.

The issue before the Commission is whether approval of Rider IER experimental tariff which imposes additional costs in this case on non-industrial customers will have the intended consequence of slowing or reversing the harmful significant trend of loss of DEP's industrial load. Should approval of Rider IER have the desired effect, over the long term the result will be lower costs to DEP's ratepayers, including those in the residential class. Conversely, should approval not have the desired effect, the non-industrial customers will bear additional costs immediately with no offsetting benefits.

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[1] These calculations are based upon the fact, as discussed above, that industrial customers are high load factor customers, meaning that their demand for power and energy remains relatively constant throughout the day, week and year, and that the industrial customers purchase an enormous amount of off-peak energy. These significant sales go to defraying DEP's fixed costs. The public interest is served by ensuring that the industrial customers continue to purchase large amounts of off-peak kWhs to contribute to the recovery of the system's fixed costs.

The Commission faces a difficult policy decision, the ultimate outcome of which can only be anticipated as it depends on future events that cannot be predicted with certainty. With some caution, I would vote to approve Rider IER as the temporary measure it is. If successful, Rider IER will provide benefits to DEP's general body of ratepayers that outweigh the costs. The problem arising from rejecting the proposal, in my view, is significant enough to be worth the risk that the hoped for benefits may not materialize.

In ratemaking, a long held principle is that so long as a customer that would otherwise leave the system stays on the utility's system and pays its variable costs plus pays a contribution to the recovery of the utility's fixed costs, all customers will be "better off" in terms of paying reduced rates. In the present case, by approving DEP's experimental Rider IER, all of DEP's customers should ultimately be in a better position than if the experimental rate is not approved. All customers will be better off for multiple reasons if Rider IER accomplishes the cessation of industry loss. First, other customer classes will not bear those additional fixed costs associated with the loss of industrial load, resulting in lower rates. In addition, the goal of job retention and economic stability for North Carolina will have been achieved.

Additionally, I would not place too much emphasis on criticisms arising from alleged lack of proof. The issue is not whether the level of industrial electric rates in DEP's service area directly has caused the loss of industrial sales, although common sense suggests that it has. Rather, the issue is what to do now to reverse this harmful trend prospectively. Proponents of Rider IER correctly recognize that appropriate price signals result in favorable economic choices in response. This is a well-recognized rate-making principle underlying much of DEP's rate structure such as time of use rates.

The majority finds that there is a lack of evidence that Rider IER will result in job retention and lower rates for all customer classes. While the issue of causation is difficult, a strict offer of proof is not necessary to serve the public interest in implementing a new rate intended to provide price signals for favorable consumer response.[1] The Commission does not need to be convinced beyond a reasonable doubt; rather, it is sufficient if the Commission believes Rider IER *may* succeed.[2] As succinctly stated by the New York court of appeals in upholding an industrial rate that was being challenged as discriminatory:

> It suffices if there is evidence that they *may* be. Even in the absence of proof that each of the affected consumers had an elasticity of demand in consequence of which it could respond to price signals, it cannot be concluded that the new rate structure will not produce significant changes in consumption patterns ... It will only be after the new rates have been in operation that the practical effect of the carrot and the club can reliably be measured.

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[1] Narragansett Electric Co., 57 P.U.R.4th 120 (R.I. PUC 1983).

[2] Conowingo Power Co..78 Md.P.S.C. 228 (M.P.S.C.1987)

New York State Council of Retail Merchants v. New York Pub. Utils. Comm'n, 384 NE2d 1282, 1288 (1978). The fact that DEP did not provide certain studies does not mean that the Commission should not approve Rider IER for the benefit of the State of North Carolina.

The proposed rate is a temporary, experimental one. Imposing a long list of requirements DEP must satisfy before implementing or maintaining a remedial measure such as Rider IER unduly hampers the parties in achieving the goal Rider IER is designed to achieve. Some issues in designing class-wide rate schedules such as free ridership are simply unavoidable. Others can be addressed as refinements over time.

The Commission clearly has the authority to place appropriate safeguards around Rider IER to closely monitor this experimental pilot program. For example, the Commission could have required DEP and the Public Staff to collaborate and submit refinements to the Rider's design to address some concerns such as the suggested employment retention requirement evasion. However, the value of any screen that would require an applicant to prove financial need or distress would in my view not outweigh the chilling effect on the program's efficacy.

Rider IER is a reasonable and measured means to address the unique decline of industrial sales and loss of manufacturing jobs in North Carolina making any rate differential between customer classes just and reasonable. This harmful condition justifies differing rates for the classes making any discrimination reasonable and permissible under G.S. 62-140. State ex. rel. Utils. Comm'n v. Carolina Util. Customers Ass'n, 348 N.C. 452, 468, 500 S.E.2d 693, 709 (1998).

The Commission should approve Rider IER as being in the public interest and for that reason I dissent from this portion of the Commission's ruling.

\s\ Edward S. Finley, Jr.
Chairman Edward S. Finley, Jr.

DOCKET NO. E-2, SUB 1030

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Duke Energy Progress, Inc., for Approval of Demand-Side Management and Energy Efficiency Cost Recovery Rider Pursuant to G.S. 62-133.9 and Commission Rule R8-69	)	NOTICE OF DECISION AND ORDER

Heard: Tuesday, September 17, 2013, at 11:15 A.M., and Wednesday, September 18, 2013, at 9:30 A.M. in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

Before: Commissioner ToNola D. Brown-Bland, Presiding, Chairman Edward S. Finley, Jr., Commissioner Susan W. Rabon, Jerry C. Dockham, and James G. Patterson

Appearances:

For Duke Energy Progress, Inc.:

Lawrence B. Somers, Duke Energy Corporation, Post Office Box 1551, NC 20, Raleigh, North Carolina 27602-1551

Robert W. Kaylor, Law Office of Robert W. Kaylor, P.A., 353 East Six Forks Road, Suite 260, Raleigh, North Carolina 27609

For the North Carolina Sustainable Energy Association:

Michael D. Youth, Post Office Box 6465, Raleigh, North Carolina 27628

For the Southern Alliance for Clean Energy:

Gudrun Thompson, Southern Environmental Law Center, 601 West Rosemary Street, Suite 220, Chapel Hill, North Carolina 27516

For the Using and Consuming Public:

David T. Drooz and Lucy E. Edmondson, Public Staff - North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: G.S. 62-133.9(d) authorizes the Commission to approve an annual rider to the rates of electric public utilities to recover all reasonable and prudent costs incurred for the adoption and implementation of new demand-side management and energy efficiency (DSM/EE) programs. The Commission is also authorized to award incentives to electric utilities for adopting and implementing new DSM/EE programs, including rewards based on the sharing of savings achieved by the programs. Commission Rule R8-69(b) provides that the Commission will each year conduct a proceeding for each electric utility to establish an annual DSM/EE rider to recover the reasonable and prudent costs incurred for adopting and implementing new DSM/EE measures previously approved by the Commission pursuant to Commission Rule R8-68. Under Commission Rule R8-69, such rider consists of the utility's forecasted cost during the rate period, similarly forecasted performance incentives (including net lost revenues) as allowed by the Commission, and an experience modification factor (EMF) rider to collect the difference between the utility's actual reasonable and prudent costs and incentives incurred and earned during the test period and the actual revenues realized during the test period under the DSM/EE rider (based on previous forecasts) then in effect.

On June 12, 2013, Duke Energy Progress, Inc. (DEP or the Company), filed an application and the associated testimony and exhibits of Robert P. Evans for the approval of a DSM/EE rider to recover reasonable and prudent forecasted DSM/EE costs, carrying costs, incremental administrative and general (A&G) costs, capital costs, taxes, and incentives, including net lost revenues (NLR) and the program performance incentive (PPI). In addition, DEP asked for approval of a DSM/EE EMF rider and, pursuant to Commission Rule R8-69(b)(2), recovery through the DSM/EE EMF of its post-test-year costs, including carrying costs and incentives incurred up to 30 days prior to the hearing in this proceeding.

On June 25, 2013, the Commission issued an Order scheduling a public hearing in this matter for September 17, 2013, immediately following the 9:30 a.m. hearing in Docket No. E-2, Subs 1031 and 1032, establishing discovery guidelines, providing for intervention and testimony by other parties, and requiring public notice. On August 28, 2013, DEP filed its affidavits of publication indicating that the Company had provided notice in newspapers of general circulation as required by the Commission's June 25, 2013 Order.

The intervention of the Public Staff is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e). On June 18, 2013, the North Carolina Sustainable Energy Association (NCSEA) filed a petition to intervene, which was granted by Commission Order issued June 24, 2013. On June 28, 2013, the Carolina Utility Customers Association, Inc. (CUCA), filed a petition to intervene, which was granted by Commission Order issued July 3, 2013. On August 29, 2013, the Southern Alliance for Clean Energy (SACE) filed a petition to intervene, which was granted by Commission Order issued August 30, 2013.

On August 15, 2013, DEP filed the supplemental testimony and exhibits of Robert P. Evans. On August 26, 2013, the Public Staff filed a motion for extension of time to file its testimony. By Order issued August 27, 2013, the Commission granted the Public Staff's motion. On September 4, 2013, the Public Staff filed the testimony of Michael C. Maness and Jack L. Floyd; and SACE filed the testimony of Natalie Mims. On September 13, 2013, DEP filed the rebuttal testimony and exhibits of Robert P. Evans and the rebuttal testimony of Jay W. Oliver.

On September 17, 2013, the hearing was held as scheduled. No public witnesses appeared at the hearing.

On October 11, 2013, DEP filed late-filed exhibits pursuant to requests by the Commission, the Public Staff, and NCSEA during the evidentiary hearing. On October 17, 2013, NCSEA filed a letter in lieu of a post-hearing brief. On October 25, 2013, the Commission issued an Order Requiring Additional Information, which Order required DEP to file additional information on or before November 1, 2013. Also on October 25, 2013, DEP filed a proposed order, and the Public Staff and SACE each filed briefs. On November 1, 2013, DEP filed the information that was required by the Commission's October 25, 2013 Order.

NOTICE OF DECISION

WHEREUPON, the Commission finds good cause to issue this Notice of Decision and Order. The Commission hereby gives notice that it will hereafter enter an Order in this docket that will, among other things, approve DEP's proposed combined DSM/EE and EMF riders for the billing period beginning December 1, 2013.

A complete Order, including findings of fact and conclusions, will be issued soon and it will be the final Order of the Commission in this docket. The time for appeal will run from the date of entry of that Order.

IT IS, THEREFORE, ORDERED as follows:

1. That the appropriate DSM/EE EMF billing factors, to be charged by DEP during the rate period are increments or decrements as follows:

Rate Class	DSM/EE EMF (Excluding GRT and NCRF)	DSM/EE EMF (Including GRT and NCRF)
Residential	(0.010) cents per kWh	(0.010) cents per kWh
General Service	0.012 cents per kWh	0.012 cents per kWh
Lighting	(0.007) cents per kWh	(0.007) cents per kWh

2. That the appropriate forward-looking DSM/EE rates to be charge by DEP during the rate period are as follows:

Rate Class	DSM/EE Rate (Excluding GRT and NCRF)	DSM/EE Rate (Including GRT and NCRF)
Residential	0.297 cents per kWh	0.307 cents per kWh
General Service	0.227 cents per kWh	0.235 cents per kWh
Lighting	0.101 cents per kWh	0.104 cents per kWh

3. That the appropriate total DSM/EE annual riders including the DSM/EE rate and the DSM/EE EMF (including the gross receipts tax and the North Carolina regulatory fee) are as follows:

Rate Class	Total DSM/EE Rider
Residential	0.297 cents per kWh
General Service	0.247 cents per kWh
Lighting	0.097 cents per kWh

4. That DEP shall file, as soon as practicable, the appropriate rate schedules and riders with the Commission in order to implement these adjustments. Such rates are to be effective for service rendered on or after December 1, 2013.

5. That DEP shall work with the Public Staff to prepare a joint proposed notice to customers of the rate changes ordered by the Commission in Docket No. E-2, Subs 1030, 1031, and 1032, and the Company shall file the proposed customer notice for Commission approval as soon as practicable.

ISSUED BY ORDER OF THE COMMISSION
This the 22nd day of November, 2013.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

DOCKET NO. E-2, SUB 1032

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Progress, Inc.,	)	
for Approval of Renewable Energy and Energy	)	ORDER APPROVING REPS AND
Efficiency Portfolio Standard Cost Recovery	)	REPS EMF RIDERS AND 2012 REPS
Rider Pursuant to G.S. 62-133.8 and	)	COMPLIANCE
Commission Rule R8-67	)	

HEARD: Tuesday, September 17, 2013, at 10:25 a.m. in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner Bryan E. Beatty, Presiding; Chairman Edward S. Finley, Jr.; Commissioners Susan W. Rabon, ToNola D. Brown-Bland, Jerry C. Dockham, and James G. Patterson

APPEARANCES:

For Duke Energy Progress, Inc.:

Lawrence B. Somers, Deputy General Counsel, Duke Energy Progress, Inc., 410 S. Wilmington Street, NC 20, Raleigh, North Carolina 27601-1849

Robert W. Kaylor, Law Office of Robert W. Kaylor, P.A., 353 E. Six Forks Road, Suite 260, Raleigh, North Carolina 27609

For the Using and Consuming Public:

Robert S. Gillam, Staff Attorney, Public Staff - North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

For the North Carolina Sustainable Energy Association:

Michael Youth, North Carolina Sustainable Energy Association, Post Office Box 6465, Raleigh, North Carolina 27628

BY THE COMMISSION: On June 12, 2013, Duke Energy Progress, Inc. (DEP or Company), filed its annual Renewable Energy and Energy Efficiency Portfolio Standard (REPS) Compliance Report and Application (Application), seeking an adjustment to its North Carolina retail rates and charges pursuant to G.S. 62-133.8(h) and Commission Rule R8-67. These provisions require the Commission to conduct an annual proceeding for the purpose of determining whether a rider should be established to permit the recovery of the incremental costs incurred to comply with the requirements of G.S. 62-133.8(b), (d) (e) and (f) and to true-up any under-recovery or over-recovery of compliance costs. DEP's Application was accompanied by the testimony and exhibits of Jonathan L. Byrd, Renewable Strategy and Compliance Manager, and Veronica I. Williams, Rates Manager. In its Application and pre-filed testimony, DEP sought approval of the proposed REPS rider, which incorporated the Company's proposed adjustments to its North Carolina retail rates.

On June 25, 2013, the Commission issued an Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines and Requiring Public Notice, in which the Commission set this matter for hearing; established deadlines for the submission of intervention petitions, intervenor testimony, and DEP rebuttal testimony; required the provision of appropriate public notice; and mandated compliance with certain discovery guidelines.

Petitions to intervene were filed by the North Carolina Sustainable Energy Association (NCSEA), and Carolina Utility Customers Association, Inc. (CUCA). These petitions were granted by the Commission on June 24, 2013 and July 3, 2013, respectively. The intervention and participation by the Public Staff is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

On August 29, 2013, DEP filed the revised exhibits of witness Veronica I. Williams. On August 30, 2013, the Public Staff filed the direct testimony and exhibits of Jay B. Lucas, Engineer – Electric Division, and the affidavit of Sonja R. Johnson, Staff Accountant – Accounting Division. On that same date, DEP filed proof of publication of the public notice required by the Commission in several newspapers of general circulation within DEP's franchised service territory.

The matter came on for hearing as scheduled on September 17, 2013. DEP presented the testimony and exhibits of witnesses Byrd and Williams, and the Public Staff presented the testimony and exhibits of witness Lucas and the affidavit of witness Johnson. CUCA did not participate in the evidentiary hearing. No other party presented witnesses, and no public witnesses appeared at the hearing.

On October 8, 2013, DEP filed Late-Filed Exhibit No. 1 in response to questions posed by the Commission during the evidentiary hearing. On October 17, 2013, DEP filed Late-Filed Exhibit No. 2 containing slides summarizing the preliminary findings of an Electric Power Research Institute (EPRI) distributed solar photovoltaic monitoring research project.

On October 17, 2013, NCSEA filed a letter in lieu of filing a post-hearing brief. NCSEA's letter stated that NCSEA does not contest DEP's proposed REPS cost recovery, but requests that the Commission require DEP to file certain additional information.

On October 25, 2013, DEP and the Public Staff filed a Joint Proposed Order.

Based upon the foregoing, DEP's verified Application, the testimony and exhibits received into evidence at the hearing, and the entire record in this proceeding, the Commission makes the following:

FINDINGS OF FACT

1. DEP is a duly organized corporation existing under the laws of the State of North Carolina, is engaged in the business of developing, generating, transmitting, distributing, and selling electric power to the public in North Carolina and South Carolina, and is subject to the jurisdiction of the North Carolina Utilities Commission as a public utility. DEP is lawfully before the Commission based upon its Application filed pursuant to G.S. 62-133.8 and Commission Rule R8-67.

2. General Statute 62-133.8(h) authorizes an electric power supplier to recover the "incremental costs" of compliance with the REPS requirements through an annual REPS rider. The "incremental costs," as defined in G.S. 62-133.8(h)(1), include the reasonable and prudent costs incurred by an electric power supplier to comply with REPS "that are in excess of the electric power supplier's avoided costs." The term "avoided costs" includes both avoided energy costs and avoided capacity costs.

3. Under Commission Rule R8-67(e)(2), the total costs reasonably and prudently incurred during the test period to purchase unbundled renewable energy certificates (RECs) constitute incremental costs. The projected costs to purchase such RECs during the billing period constitute forecasted incremental costs. The test period for this proceeding is the 12 months from April 1, 2012, through March 31, 2013. The billing period for this proceeding is the 12 months beginning on December 1, 2013 and ending on November 30, 2014.

4. DEP has agreed to provide REPS compliance services, including the procurement of RECs, to the following wholesale electric power suppliers (Wholesale Customers): the Town of Sharpsburg, the Town of Stantonsburg, the Town of Lucama, the Town of Black Creek, and the City of Waynesville.

5. DEP has complied with the 2012 general requirement and solar set-aside requirement for itself and the Wholesale Customers for which the Company is providing compliance services. Pursuant to the Commission's November 29, 2012 Order Modifying the Poultry and Swine Waste Set-Aside Requirements and Granting Other Relief in Docket

No. E-100, Sub 113 (2012 Relief Order), the swine waste set-aside requirement for 2012 was eliminated, and the poultry waste set-aside requirement was delayed for one year.

6. DEP has appropriately calculated its avoided costs and incremental REPS compliance costs for the test period and billing period. For purposes of establishing the REPS Experience Modification Factor (EMF) rider in this proceeding, DEP's incremental costs for REPS compliance during the test period were $20,203,579, including costs incurred for its Wholesale Customers, and these costs were reasonably and prudently incurred. The Company's projected incremental costs for REPS compliance for the billing period total $21,558,084.

7. DEP's over-recovery of incremental costs amounts to $986,645 for the EMF period, August 2012 through March 2013.[1]

8. The appropriate monthly amount of the REPS EMF rider per customer account, excluding gross receipts tax and the regulatory fee, to be collected during the billing period is ($0.13) for residential accounts, $0.35 for general service accounts, and ($2.40) for industrial accounts.

9. The appropriate monthly amount of the REPS rider per customer account, excluding gross receipts tax and the regulatory fee, to be collected during the billing period is $0.32 for residential accounts, $7.48 for general service accounts, and $32.02 for industrial accounts.

10. The combined monthly REPS and REPS EMF rider charges per customer account, excluding gross receipts tax and the regulatory fee, to be collected during the billing period is $0.19 for residential accounts, $7.83 for general service accounts, and $29.62 for industrial accounts.

11. DEP's combined REPS and REPS EMF riders to be charged to each customer account for the billing period are within the annual cost caps established in G.S. 62-133.8(h)(4).

12. The reasonable and prudent cost of REPS-related research activities funded by DEP during the test period and planned for the billing period are recoverable pursuant to G.S. 62-133.8(h)(1)(b). The research costs expended by DEP during the test period were prudent, reasonable and within the statute's $1,000,000 annual limit.

13. DEP's annual REPS Compliance Report pursuant to Commission Rule R8-67(c) demonstrates that DEP is in compliance with G.S. 62-133.8(b), (d), (e) and (f). DEP's 2012 REPS compliance report should be approved.

14. DEP projects that the Company will comply with the general and solar REPS requirements in 2013 and that the Company will have sufficient poultry RECs to meet its poultry waste set-aside compliance obligation in 2013 as well. However, DEP will not meet its 2013 swine waste set-aside requirement.

[1] Because DEP updated the test period in its last REPS rider proceeding, Docket No. E-2, Sub 1020, but did not do so in this proceeding, the EMF period in this proceeding includes only eight months.

15. DEP's Residential SunSense Program, a 5-year experimental program approved by the Commission in Docket No. E-2, Sub 979 on November 15, 2010, and amended on February 20, 2013, has been an important component of DEP's efforts to comply with the solar set-aside requirement. Based on changes in the price and availability of solar RECs, however, it is appropriate for DEP to review both the cost-effectiveness of increasing the enrollment of participants in the Residential SunSense Program for calendar year 2015 and the information gained from the program, and file the results of this review in Docket No. E-2, Sub 979. In addition, DEP should include the results of this review in its 2014 REPS compliance filing.

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

These findings of fact are essentially informational, procedural, and jurisdictional in nature and are uncontroverted.

General Statute 62-133.8(h)(4) requires the Commission to allow an electric utility to recover through an annual rider all of its incremental, reasonable, and prudent costs incurred to comply with G.S. 62-133.8. General Statute62-133.8(h)(1) provides that "incremental costs" means all reasonable and prudent costs incurred by an electric power supplier to comply with the REPS requirements that are in excess of the electric power supplier's avoided costs, other than those costs recovered pursuant to G.S. 62-133.9.

Commission Rule R8-67(e)(1) provides that the Commission shall schedule an annual public hearing to review an electric utility's REPS compliance costs. Further, subdivision (e)(3) of Rule R8-67 provides that the test period for each utility shall be the same as the test period for purposes of Commission Rule R8-55. Pursuant to Rule R8-55, DEP's test period is the 12 months ending March 31 of each year. Therefore, DEP proposed that the test period for its REPS cost recovery proceeding be the 12 months ending March 31, 2013.

Commission Rule R8-67(e)(4) provides that the REPS and REPS EMF riders shall be in effect for a fixed period which "shall coincide, to the extent practical, with the recovery period for the cost of fuel and fuel-related cost rider established pursuant to Rule R8-55." In its current fuel charge adjustment proceeding, Docket No. E-2, Sub 1031, and in this proceeding, DEP proposed that its rate adjustments take effect on December 1, 2013, and remain in effect for a 12-month period. This period is referred to herein as the "billing period."

The test and billing periods proposed by DEP were not challenged by any party. The Commission concludes that the appropriate test period for use in this proceeding is the 12 months ending March 31, 2013, and that the appropriate billing period is the 12 months ending November 30, 2014.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4-5

The evidence for these findings of fact can be found in DEP's Application, the direct testimony and exhibits of DEP witness Byrd, Public Staff witness Lucas and the requirements of G.S. 62-133.8. The Commission also takes judicial notice of information in the North Carolina Renewable Energy Tracking System (NC-RETS) pertaining to DEP's retirement of RECs.

DEP witness Byrd described in his testimony the Company's efforts to comply with the REPS requirements, and he discussed these efforts more fully in the REPS compliance report, which was admitted into evidence as Byrd Exhibit No. 1. Witness Byrd testified that the report provided the information required by Commission Rule R8-67(c) in the aggregate for DEP and the Wholesale Customers for which DEP has agreed to provide REPS compliance services. No party took issue with DEP's purchase of RECs for the Wholesale Customers.

For calendar year 2012, the Company must generally supply an amount of at least 3% of its previous year's North Carolina retail electric sales by a combination of renewable energy and energy reductions due to the implementation of energy efficiency measures (general requirement). As part of the general requirement, the Company must supply energy in the amount of at least 0.07% of the previous year's North Carolina retail sales from solar resources. In 2013, these percentages required for compliance remain the same. Beginning in 2012, G.S. 62-133.8(e) and (f) require DEP and other electric suppliers in North Carolina, in the aggregate, to procure a certain portion of their renewable energy requirements from swine and poultry waste resources. In its 2012 Relief Order, however, the Commission eliminated the swine waste set-aside for 2012, and delayed for one year the poultry waste set-aside requirements for DEP and other electric suppliers.

DEP witness Byrd testified that the Company's general REPS requirement for 2012, based on 3% of the total of DEP's prior year North Carolina retail sales of 37,353,311 MWH and the Wholesale Customers' sales of 155,584 MWh, is 1,125,269 RECs. DEP forecasted the total requirement to be 1,110,736 RECs in 2013 and 1,122,357 RECs in 2014. Witness Byrd testified that the Company has submitted for retirement the RECs necessary to meet its total obligation for calendar year 2012.

Witness Byrd further testified that the Company's solar requirement in 2012 was equivalent to 26,259 solar RECs, and DEP forecasts its solar requirement to be 25,917 RECs in 2013 and 26,188 RECs in 2014. He confirmed that the Company has met its solar set-aside requirement for 2012 by submitting for retirement 26,259 solar RECs. Witness Byrd also testified that DEP is retiring an additional 7,471 in-state solar RECs beyond those required for its solar set-aside requirement as a part of meeting its general requirement. He testified that this use of solar RECs for DEP's general requirement did not increase costs for customers because solar RECs are available at prices in the range of other general RECs.

Public Staff witness Lucas testified that the price of solar RECs available in the market has declined greatly over the past several months to the point that their cost is roughly equal to that of general RECs and that DEP's use of solar RECs to meet the general requirement did not concern the Public Staff. He recommended that DEP's 2012 REPS compliance report be approved.

Based on the evidence presented and the record as a whole, the Commission finds and concludes that DEP and the Wholesale Customers for which it is providing REPS compliance services have fully complied with the REPS requirements for 2012, and that DEP's 2012 REPS compliance report should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 6-11

The evidence supporting these findings of fact appears in DEP's Application, the testimony and exhibits of DEP witness Byrd, the testimony and revised exhibits of DEP witness Williams, the testimony of Public Staff witness Lucas, and the affidavit of Public Staff witness Johnson.

DEP witness Byrd testified that in addition to the costs of purchases of renewable power and RECs, DEP seeks to recover the incremental labor costs associated with REPS compliance activities, the costs for research and development activities to further emerging renewable technologies, and the incremental costs for implementation and operation of the North Carolina Renewable Energy Tracking System (NC-RETS).

In regard to the methodology used by DEP to calculate the incremental costs associated with its purchases from renewable energy facilities, witness Byrd explained that for each contract with a renewable energy facility where DEP is purchasing bundled energy and RECs, the Company calculated the applicable avoided cost over the term of the contract. This avoided cost was then subtracted from the total cost associated with the renewable energy purchase to arrive at the incremental cost for that renewable energy purchase during the period in question. The costs associated with unbundled REC purchases are completely incremental and are included directly in the calculation of rates.

Witness Williams' revised exhibits show that DEP's incremental costs of retail REPS compliance were $13,005,901 for the EMF period. The forecasted incremental costs for retail REPS compliance for the billing period amounted to a total of $21,471,852. Witness Williams' exhibits also show a $986,645 over-recovery of incremental costs for the EMF period.

Witness Williams, after making minor adjustments to the inputs regarding general REC costs among customer classes and updating for changes in the gross receipts tax and regulatory fee multiplier, as recommended by the Public Staff, calculated the monthly REPS rider amounts of $0.32 for the residential class, $7.48 for the general class, and $32.02 for the industrial class. She also calculated the monthly REPS EMF rider amounts of ($0.13) for the residential class, $0.35 for the general class, and ($2.40) for the industrial class. Thus, the combined monthly REPS and REPS EMF rates are $0.19 for the residential class, $7.83 for the general class and $29.62 for the industrial class, not including gross receipts tax or the regulatory fee.

Public Staff witnesses Lucas and Johnson testified that they reviewed and analyzed the REPS incremental costs for which DEP has requested recovery in this proceeding, found them to be appropriate, and recommended their approval. No other party presented any evidence regarding DEP's REPS incremental costs.

The REPS charges proposed by DEP are significantly less than the annual cost caps established in G.S. 62-133.8(h)(4), which are $12.00 for residential customers, $150.00 for general service customers and $1,000.00 for industrial customers. Further, based on the evidence the Commission concludes that DEP's incremental REPS costs for the test period are reasonable and prudent and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence supporting this finding of fact appears in the testimony and exhibits of DEP witness Byrd and the testimony of Public Staff witness Lucas.

In compliance with the Commission's November 16, 2012 Order Approving REPS and REPS EMF Riders and 2011 REPS Compliance in Docket No. E-2, Sub 1020, DEP witness Byrd supplied testimony and exhibits on the results and status of various research studies for which DEP sought cost recovery in this proceeding. The Company provided the following information:

- DEP partnered with Duke University to study the potential in North Carolina for injection of swine biogas into interstate pipelines with subsequent centralized electricity generation. This research provides insight into the relative economics of directed swine biogas compared to individual on-farm projects. The study results are final and were made public on April 25, 2013.

- The Company is participating in an EPRI study to provide detailed characterization of distributed photovoltaic (PV) output variability in order to study the impacts of scale and penetration levels on distribution feeders. This study is part of a broader EPRI initiative to collect data at 200-400 sites distributed nationally. Results from the study were expected in August 2013, but had not yet been received as of the date of the hearing. DEP Late-Filed Exhibit No. 2, filed on October 17, 2013, contains slides providing some of the preliminary findings from the study. DEP agreed to file any final study results as a late-filed exhibit once received.

- The Company commissioned the University of North Carolina to analyze wind resources outside the barrier islands where potential may exist for large scale offshore wind projects. There is not currently sufficient data to determine the feasibility of offshore wind projects in this area. The study is ongoing, and Byrd Exhibit No. 6 details the progress of the study through April 2012.

- The Company subscribes to various EPRI programs, including programs on solar energy, biomass, and the economics and technology status of renewable energy. EPRI designates such study results as proprietary or as trade secrets and licenses the results to its members, including the Company. As such, DEP may not disclose the information publicly. non-members may access these studies for a fee.

- The Company subscribes to Bloomberg New Energy Finance's Solar Insights Service. The service provides in-depth analysis of the drivers of growth in solar energy. Bloomberg designates these articles as proprietary or as trade secrets and licenses such reports to subscribers, including the Company. As such, DEP may not disclose the information publicly. Interested parties can obtain copies of these reports via Bloomberg subscription. Non-members may access this service for a fee.

According to Byrd Exhibit Nos. 2 and 3, DEP spent $273,905 on REPS-related research during the test period and $76,144 during the August 2012 through March 2013 EMF period. The Company plans to spend $66,882 during the billing period. These amounts are within the $1,000,000 annual limit established by G.S. 62-133.8(h)(1)(b).

During the evidentiary hearing, DEP agreed to adopt the reporting requirements established for Duke Energy Carolinas, LLC (DEC), in Docket No. E-7, Sub 1034 (DEC REPS Order), regarding research studies being funded via the REPS rider. DEP will file with its 2014 REPS rider application the study results for any studies the cost of which DEP has recovered via the REPS rider. For those studies that are subject to confidentiality agreements, DEP will provide procedures for third parties to access the results. For research projects sponsored by EPRI, DEP will provide the overall program number and specific project number for each project, as well as an internet address or mailing address that will enable third parties to inquire about the terms and conditions for access to any portions of the study results that are proprietary.

In NCSEA's post-hearing letter, NCSEA requested that the Commission include in the present order an ordering paragraph, similar to Ordering Paragraph No. 7 in the DEC REPS Order in Docket No. E-7, Sub 1034, directing DEP to include the results of REPS-related studies in DEP's future REPS rider applications. In addition, NCSEA requested that the Commission remind DEP of its commitment to file the most recent findings of the EPRI distributed PV monitoring study and the UNC offshore wind study as a late-filed exhibit.

On October 17, 2013, DEP filed Late-Filed Exhibit No. 2 containing slides summarizing the preliminary findings of the EPRI distributed PV monitoring research project. In addition, DEP stated in Late-Filed Exhibit No. 2 that it will file with the Commission any further EPRI reports regarding the distributed PV monitoring study.

Based on the evidence, the Commission concludes that the research costs incurred by DEP during the test period were reasonable and prudent and should be recovered from ratepayers. In addition, the Commission concludes that it is appropriate for DEP to provide, in its future REPS rider applications, the results of its REPS-related research when those results are publicly available, and the procedures for third parties to access the results when they are proprietary. For research projects sponsored by EPRI, DEP should provide the overall program number and specific project number for each project, as well as an internet address or mailing address that will enable third parties to inquire about the terms and conditions for access to any portions of the study results that are proprietary.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 13-14

The evidence supporting these findings of fact appears in DEP's Application, the testimony and exhibits of DEP witness Byrd, the testimony of Public Staff witness Lucas, and the affidavit of Public Staff witness Johnson.

Witness Byrd testified that the Company is well-positioned to comply with its general requirement in 2013 through a diverse and balanced portfolio of renewable resources. The Company's efforts to comply with the general requirement included its continued implementation of energy efficiency programs and the purchase of RECs from renewable energy facilities.

Witness Byrd also testified that the swine waste set-aside requirement, which had been eliminated for 2012, would be 25,917 RECs in 2013 and 26,188 RECs in 2014. According to witness Byrd, during the test period, the Company (1) continued direct negotiations for additional supplies of both in-state and out-of-state resources; (2) partnered with Duke University to study the potential in North Carolina for injection of swine biogas into interstate pipelines with subsequent centralized generation and production of swine waste RECs; and (3) worked diligently to understand the technological, permitting, and operational risks associated with various methods of producing qualifying swine RECs. Witness Byrd stated that the Company remains committed to satisfying its statutory obligation for the swine waste set-aside. Nevertheless, its currently executed contracts were inadequate for compliance in 2013, and DEP projected that it would not meet its swine waste set-aside requirement in 2013.

Witness Byrd also testified that the poultry waste set-aside requirement, which had been delayed for one year, was DEP's pro-rata share of 170,000 megawatt-hours (MWh) in 2013 and 700,000 MWh in 2014, based on its ratio of the prior year retail sales to the total statewide retail sales. He stated that the Company projected that it would have sufficient poultry RECs to meet its compliance obligation in 2013, provided that satisfactory performance from existing suppliers continued through the end of the year. He further stated that during the test period the Company had (1) sought additional renewable energy proposals from poultry waste-to-energy developers; (2) continued direct negotiations with multiple counterparties; and (3) worked diligently to understand the technological, permitting, and operational risks associated with various methods of producing qualifying poultry RECs. Witness Byrd testified that the Company remains committed to satisfying its statutory obligation for the poultry waste set-aside, will continue to reasonably and prudently pursue procurement of these resources, and projects that it will have sufficient poultry RECs to meet its compliance obligation in 2013.

On September 16, 2013, DEP, along with other electric suppliers, requested a modification and delay to the 2013 swine and poultry waste set-aside requirements in Docket No. E-100, Sub 113 pending before the Commission. The Commission held an evidentiary hearing on November 5, 2013 to ascertain whether the electric suppliers have made a reasonable effort to meet their compliance requirements for 2013.

Public Staff witness Lucas testified that he reviewed DEP's 2012 compliance report and found that it meets the requirements of Commission Rule R8-67(c) for both DEP and the Wholesale Customers.

No other party presented any evidence on this issue. The Commission concludes that DEP's 2012 REPS compliance report meets the requirements of Commission Rule R8-67(c) and demonstrates that DEP and the Wholesale Customers complied with G.S. 62-133.8(d) in 2012.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The evidence supporting this finding of fact appears in the testimony of DEP witness Byrd and Public Staff witness Lucas.

Public Staff witness Lucas testified that the experimental Residential SunSense Program was originally approved by the Commission in Docket No. E-2, Sub 979 on November 15, 2010, and amended on February 20, 2013. The program provides a one-time upfront payment and a small monthly payment per installed kilowatt (kW) to installers of small (10 kW or less) residential solar photovoltaic systems, with a total annual enrollment not to exceed one megawatt capacity on a calendar year basis. DEP retains the RECs generated by the program, and the costs of the program are recovered by DEP through its REPS rider. The program is available to new applicants until December 31, 2015.

Public Staff witness Lucas also testified that due to the large decrease in solar REC prices over the past year the RECs created by the program have become more expensive relative to other solar RECs. He recommended, therefore, that DEP review the cost-effectiveness of the program to determine if it is still necessary for REPS compliance.

In response to Commission questions, witness Byrd testified that while the program is a small component of DEP's compliance effort, the RECs from the program provide some diversity to their compliance portfolio that is beneficial. Witness Byrd further testified that:

> I think when I look across the country, residential solar applications and installations are growing dramatically, so I believe that in the future, that could play a greater role in our compliance effort. So I think that the program is small, it is capped and it provides the Company with valuable insights about when residential customers are willing to invest in solar systems and the challenges that it may encounter.

T, at p. 46.

Witness Byrd further testified that because the Residential SunSense Program is an experimental 5-year program the Company will continue to review the program.

In NCSEA’s post-hearing letter, NCSEA requested that the Commission require DEP to file in Docket No. E-2, Sub 979 as much advance notice to the residential solar business community as reasonably possible if DEP decides to propose changes to the Residential SunSense Program.

The Commission agrees with DEP that the Residential SunSense Program provides useful information regarding the residential solar market and, based on the limited size of the program, continues to provide value as part of DEP’s compliance efforts. Nonetheless, the Commission further finds and concludes that DEP should review both the cost-effectiveness of continued enrollment in the Residential SunSense program through calendar year 2015 and the information gained from the program, and file the results of this review in Docket No. E-2, Sub

979 as soon as reasonably practicable. In addition, DEP should include the results of this review in its 2014 REPS compliance filing.

IT IS, THEREFORE, ORDERED as follows:

1. That effective for service rendered on and after December 1, 2013, and expiring on November 30, 2014, DEP shall be allowed to charge each residential customer a monthly EMF of ($0.13) and a REPS rider in the amount of $0.32, for a total of $0.19; DEP shall be allowed to charge each general service customer a monthly EMF of $0.35 and a REPS rider in the amount of $7.48, for a total of $7.83; and DEP shall be allowed to charge each industrial customer a monthly EMF of ($2.40) and a REPS rider in the amount of $32.02, for a total of $29.62, excluding gross receipts tax and the regulatory fee.

2. That DEP shall file appropriate rate schedules and riders with the Commission to implement the provisions of this Order as soon as practicable.

3. That DEP shall work with the Public Staff to prepare a joint proposed notice to customers of the rate changes ordered by the Commission in Docket No. E-2, Subs 1030, 1031, and 1032, and the Company shall file the proposed customer notice for Commission approval as soon as practicable.

4. That DEP's 2012 REPS compliance report is hereby approved, and the RECs in DEP's 2012 compliance sub-accounts in NC-RETS shall be retired.

5. That DEP shall file in all future REPS rider applications the results of REPS-related studies the costs of which were recovered via its REPS EMF rider, including the overall program number and specific project number for each project sponsored by EPRI; and for those studies that are subject to confidentiality agreements, information (including an internet or mailing address) regarding how parties can access the results of those studies.

6. That DEP shall review both the cost-effectiveness of continued enrollment in the Residential SunSense Program through calendar year 2015 and the information gained from the program, and file the results of this review in Docket No. E-2, Sub 979 as soon as reasonably practicable. In addition, DEP shall include the results of this review in its 2014 REPS compliance filings.

ISSUED BY ORDER OF THE COMMISSION.
This the 25th day of November, 2013.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

DOCKET NO. E-7, SUB 1032

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Carolinas, LLC,	)	
for Approval of New Cost Recovery	)	ORDER APPROVING DSM/EE
Mechanism and Portfolio of Demand-Side	)	PROGRAMS AND STIPULATION
Management and Energy Efficiency Programs	)	OF SETTLEMENT
	)	

HEARD IN: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, Tuesday, August 20, 2013, at 9:30 a.m.

BEFORE: Chairman Edward S. Finley, Jr., Presiding; and Commissioners Bryan E. Beatty, Susan W. Rabon, ToNola D. Brown-Bland, Jerry C. Dockham, and James G. Patterson

APPEARANCES:

For Duke Energy Carolinas, LLC (DEC or Company):

Lawrence B. Somers, Deputy General Counsel, Duke Energy Corporation, Post Office Box 1551/PEB 20, Raleigh, North Carolina 27602

For the North Carolina Waste Awareness and Reduction Network (NC WARN):

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For the North Carolina Sustainable Energy Association (NCSEA) and the Environmental Defense Fund (EDF):

Michael Youth, 1111 Haynes Street, Suite 111, Raleigh, North Carolina 27604

For the Southern Alliance for Clean Energy (SACE), the South Carolina Coastal Conservation League (CCL), the Natural Resources Defense Council (NRDC), and the Sierra Club:

Gudrun Thompson, Southern Environmental Law Center, 601 West Rosemary Street, Suite 220, Chapel Hill, North Carolina 27516

For the Carolina Utility Customers Association, Inc. (CUCA):

Robert F. Page, Crisp, Page & Currin, LLP, 4010 Barrett Drive, Suite 205, Raleigh, North Carolina 27609-6622

For the Using and Consuming Public:

Lucy E. Edmondson, Staff Attorney, Public Staff - North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: General Statute 62-133.9(d) authorizes the Commission to approve an annual rider to the rates of electric public utilities to recover all reasonable and prudent costs incurred for the adoption and implementation of new demand-side management (DSM) and energy efficiency (EE) programs. The costs include, but are not limited to, all capital costs, including costs of capital and depreciation expense, administrative costs, implementation costs, incentive payments to participants, and operating costs. The annual DSM/EE rider is composed of two parts: one, the utility's forecasted cost, including incentives during the rate period, and two, an experience modification factor (EMF) to collect the difference between the utility's actual reasonable and prudent costs incurred during the test period and actual revenues realized during the test period. The Commission is also authorized to approve incentives for the utility for the adoption and implementation of new DSM and EE programs, including appropriate rewards based on the sharing of savings achieved by the programs.

On February 9, 2010, in Docket Number E-7, Sub 831, the Commission issued an Order Approving Agreement and Joint Stipulation of Settlement Subject to Certain Commission-Required Modifications and Decisions on Contested Issues (Save-a-Watt Order). The Save-a-Watt Order approved the application of DEC to initiate the Company's modified save-a-watt proposal establishing DSM/EE programs and a DSM/EE cost recovery mechanism. Save-a-watt was approved as a pilot program for four years, ending on December 31, 2013.

On March 6, 2013, DEC filed its Application in the present docket for approval of a new DSM/EE cost recovery mechanism and a new portfolio of DSM/EE programs for service rendered on and after January 1, 2014. The Company also filed the testimony and exhibits of Jane L. McManeus, Timothy J. Duff, and Ashlie J. Ossege.

On March 28, 2013, the Commission issued its Order Scheduling Hearing Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice. Petitions to intervene were filed and granted to NCSEA, CUCA, Piedmont Natural Gas Company, Inc., NC WARN, Public Service Company of North Carolina, Inc., EDF, SACE, CCL, NRDC, and the Sierra Club. The intervention of the Public Staff - North Carolina Utilities Commission (Public Staff) is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

On June 28, 2013, the Commission issued an Order requiring the Company to file its third-party study of energy efficiency potential (EE Study) and supplemental testimony. On July 15, 2013, DEC filed the EE Study and the supplemental testimony and exhibits of witness Duff. By Commission Order issued on July 24, 2013, Richard G. Stevie, Ph.D., was authorized to adopt the testimony and exhibits of witness Ossege.

On August 7, 2013, several of the intervenors filed testimony and exhibits The Public Staff filed the joint testimony and exhibits of Richard F. Spellman and Warren Hirons, and the testimony and exhibits of John R. Hinton, Michael C. Maness, and Jack L. Floyd. NCSEA and EDF filed the testimony and exhibits of Susan F. Tierney, Isaac Panzarella, and Brad Copithorne. SACE, CCL, NRDC, and the Sierra Club filed the testimony and exhibits of Natalie Mims. NC WARN filed the testimony and exhibit of Satana DeBerry and Deborah B. Warren.

On August 13, 2013, NCSEA and EDF filed a motion requesting that witnesses Copithorne and Panzarella be excused from attending the hearing and that their testimony be stipulated into the record. The motion was granted by Commission Order of August 14, 2013.

On August 15, 2013, the Public Staff filed a Notice of Settlement stating that the Public Staff and DEC had settled all issues in this proceeding and requesting an additional extension of time for the filing of their agreement, stipulation, and supporting testimony. The request was granted on August 16, 2013. On the same date, the Public Staff was verbally granted an extension of time for the filing of the stipulating parties' Agreement and Stipulation of Settlement (Stipulation).

On August 16, 2013, DEC filed the rebuttal testimony of witnesses Duff and Stevie. On August 18, 2013, the Public Staff filed the settlement testimony of witness Maness, and the Company filed the settlement testimony and exhibits of witnesses Duff and McManeus.

On August 19, 2013, the Public Staff filed the Stipulation of the Company, NCSEA, EDF, SACE, CCL, NRDC, and the Public Staff (Stipulating Parties). With the filing of the Stipulation, NCSEA and EDF withdrew the testimony and exhibits of witness Tierney; the Public Staff withdrew the joint testimony and exhibits of witnesses Spellman and Hirons; SACE, CCL, NRDC, and the Sierra Club withdrew the testimony of witness Mims; and the Company withdrew the rebuttal testimony of witness Stevie.

The evidentiary hearing was held as scheduled on August 20, 2013. The testimony of NCSEA and EDF witnesses Panzarella and Copithorne was stipulated into the record by agreement of the parties. The Company asked that the portion of witness Duff's rebuttal testimony relating to the testimony of witness Mims be stricken. Thereafter, the Commission admitted into evidence the prefiled direct, supplemental, rebuttal, and settlement testimony and the exhibits, revised exhibits, supplemental exhibits, and settlement exhibit of witness Duff; the direct and settlement supporting testimony and exhibits, revised exhibits, and settlement exhibits of witness McManeus; the direct testimony and exhibits of witness Ossege; and the direct testimony and exhibits of witness Stevie adopting the testimony and exhibits of witness Ossege.

After the testimony and exhibits of the Company were admitted into evidence, seven public witnesses testified. Phil Azar, appearing on behalf of Clean Energy Durham: (a) stated that his organization did not believe that DEC's current and proposed EE programs were effective for low-income customers; (b) supported providing dedicated funding for energy education, EE training and services targeting low-income communities; and (c) proposed that these services and education be provided by organizations such as the North Carolina Housing Finance Agency (NCHFA).

Beth McKee-Huger, Executive Director of the Greensboro Housing Coalition, testified regarding how EE programs that are well planned and properly implemented could improve the health and well-being of low-income families and decrease the rate of electric service disconnections.

Carl Sigel, testifying on behalf of North Carolina Interfaith Power and Light, stated that his organization supported the low-income EE program proposed by NC WARN in lieu of the Company's proposed low-income EE program. He stated that his organization believed that assisting low-income residents was a responsibility of all citizens of North Carolina, that EE and weatherization can be best provided by existing community organizations, that the NCHFA has the infrastructure to manage a low-income EE program, and that such a program improves the housing stock and lives of low-income residents.

Sharon Goodson, testifying on behalf of the North Carolina Community Action Association, explained how her organization's statewide network of 36 community action agencies and four limited purpose agencies has successfully completed numerous weatherization projects for low-income and elderly residents, reducing their economic burden and creating jobs in the local communities. With regard to the marketing and delivery of EE services to low-income people across North Carolina, she stressed the importance of using community-based organizations that already have an established and proven infrastructure for doing so.

Sara Rudolph, testifying on behalf of Franklin-Vance-Warren Opportunity, Incorporated, a non-profit community action agency, pointed out the large amount of stimulus funding for weatherization that had been filtered through community action agencies. She asserted that such agencies have a proven monitoring system to ensure that monies are properly directed to ensure quality results.

William Delamar, a licensed home inspector, pointed out that inefficiency due to poorly weatherized homes increases demand for electric power, the amount of greenhouse gases, and the cost of new power plants. He stated that conservation and efficiency are the most effective way of reducing costs. Mr. Delamar testified that he had reviewed the low-income EE program filed by NC WARN, and he supported allowing the NCHFA to administer it because more money would stay in the State, greater efficiency would occur, more homes would be served, and monies would be directed to contractors in North Carolina, creating and sustaining jobs.

Alfred Ripley, testifying on behalf of the North Carolina Justice Center, spoke in support of NC WARN's proposed low-income EE program. He stated that the proposal is reasonable, a significant improvement over current programs, and will help many more North Carolinians afford electrical service.

Following the public witnesses, DEC witnesses Duff, McManeus, and Stevie presented testimony in support of the Stipulation. NC WARN presented the testimony of witnesses Deberry and Warren in support of NC WARN's Community and Community Enhanced EE programs. The testimony and exhibits of Public Staff witnesses Floyd and Hinton were stipulated into the record by agreement of the parties, and the Public Staff presented the testimony of witness Maness in support of the Stipulation. The Company's application and the Stipulation were also entered into the record.

On September 23, 2013, the Stipulating Parties filed an amendment to the Stipulation adding the Sierra Club as a Stipulating Party.

Based upon DEC's Application, the testimony and exhibits received into evidence at the hearing, the Stipulation, and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

1. DEC is duly organized as a public utility operating under the laws of the State of North Carolina, and is subject to the jurisdiction of the Commission. The Company is engaged in the business of generating, transmitting, distributing, and selling electric power to the public in the Central and Western portions of North Carolina and Western South Carolina. DEC is a wholly-owned subsidiary of Duke Energy Corporation, and its office and principal place of business are located in Charlotte, North Carolina. DEC is lawfully before the Commission based upon its Application filed pursuant to G.S. 62-133.9 and Commission Rules R8-68 and R8-69.

2. The Commission has jurisdiction over this Application and the Stipulation pursuant to the Public Utilities Act. A utility must submit all cost-effective DSM and EE options for which the utility requests incentives to the Commission for approval and seek appropriate cost recovery pursuant to G.S. 62-133.9 and Commission Rules R8-68 and R8-69.

3. On March 6, 2013, the Company filed an Application for approval of a new DSM/EE cost recovery mechanism and a new portfolio of DSM/EE programs for service rendered on and after January 1, 2014.

4. On August 19, 2013, the Stipulating Parties filed the Stipulation, which resolves all issues among the Stipulating Parties associated with Docket No. E-7, Sub 1032, including DEC's proposed portfolio of DSM/EE programs and the appropriate DSM/EE cost recovery and incentive mechanism (Mechanism).

5. The proposed portfolio consists of the following EE and DSM programs, which are new EE or DSM measures pursuant to G.S. 62-133.9:

Residential Customer Programs: Appliance Recycling Program, Energy Assessments Program, Energy Efficiency Education Program, Energy Efficient Appliances and Devices, HVAC Energy Efficiency Program, Multi-Family Energy Efficiency Program, My Home Energy Report, Income-Qualified Energy Efficiency and Weatherization Program, and Power Manager;

Non-Residential Customer Programs: Non-Residential Smart $aver® Energy Efficient Food Service Products Program, Non-Residential Smart $aver® Energy Efficient HVAC Products Program, Non-Residential Smart $aver® Energy Efficient IT Products Program, Non-Residential Smart $aver Energy Efficient Lighting Products Program, Non-Residential Smart $aver® Energy Efficient Process Equipment Products Program, Non-Residential Smart $aver® Energy Efficient Pumps and Drives Products Program, Non-Residential Smart $aver® Custom Program, Non-Residential Smart $aver® Custom Energy Assessments Program, PowerShare®, and PowerShare® CallOption Pilot Program: Energy Management and Information Services Program.

6. With the exception of the Income-Qualified Energy Efficiency and Weatherization Program and the Energy Management and Information Services Program pilot, the proposed programs are cost-effective under the Utility Cost Test (UCT). All of the programs in the proposed portfolio are cost-effective under the Total Resource Cost (TRC) test except the Energy Management and Information Services Program pilot.

7. The Company's proposed Income-Qualified Energy Efficiency and Weatherization Program, which meets all the filing requirements of Commission Rule R8-68(c)(2), has two parts: (a) weatherization and equipment replacement assistance and (b) distribution of EE products. It is designed to assist low-income customers in reducing energy use in their homes. The program is approved in its entirety as being in the public interest because it both encourages EE and targets low-income ratepayers who could derive a great economic benefit from EE programs.

8. The portfolio of DSM and EE programs filed by DEC should be approved as filed, except: (a) the programs should be approved without a specific term and (b) the Company should clarify that its proposed Non-Residential $mart-Saver® Custom Program and Non-Residential Smart Saver® Custom Energy Assessments Program do not exclude bottoming-cycle combined heat and power (CHP) or the waste heat recovery components of topping-cycle CHP.

9. NC WARN has not presented sufficient evidence justifying its proposed revisions to DEC's Multi-Family EE Program, or the adoption of NC WARN's proposed Community Enhanced Program in lieu of DEC's Income-Qualified Energy Efficiency and Weatherization Program. As offered by the Company and provided for in the Stipulation, however, it is appropriate for the Company to meet with NC WARN, the Public Staff, and other interested intervenors within 90 days of the issuance of this Order to discuss NC WARN's proposals, with the intent of developing a Community Enhanced Program and revisions to DEC's Multi-Family EE Program to present to the Company's Carolinas Energy Efficiency Collaborative (Collaborative) for discussion and refinement, and possibly filing such proposals with the Commission.

10. As provided in the Stipulation, on-bill repayment (OBR) and CHP should be discussed and considered as part of the Collaborative, with such discussion and consideration to commence no later than December 31, 2013. The Company should report to the Commission the results of the OBR and CHP Collaborative consideration in connection with its next DSM/EE rider proceeding. To the extent the discussion and consideration of either OBR or CHP is ongoing, the Company should provide a status update in connection with its next DSM/EE rider proceeding, with a report to follow in a subsequent DSM/EE rider proceeding.

11. DEC's request for the following waivers of Commission Rules are appropriate and should be granted: (a) waiver of Rule R8-69(d)(3) to (i) allow the Company more flexibility in implementing and managing the opt-out elections of individual commercial customers with annual energy usage of not less than 1,000,000 kilowatt-hours (kWh) and industrial customers, as set forth in the Commission's Order Granting Waiver, in Part, and Denying Waiver, in Part issued on April 6, 2010, in Docket No. E-7, Sub 938 (Sub 938 Waiver Order), and (ii) allow the Company to implement its proposal for an additional election period in March; and (b) waivers of Rules R8-69(a)(4) and R8-69(a)(5) as approved by the Commission in its June 3, 2010, Order

on Motions for Reconsideration in Docket No. E-7, Sub 938 (Sub 938 Second Waiver Order), for the duration of the Mechanism, unless otherwise ordered by the Commission in the future. The granting of these waivers, and the Company's actions thereunder, may result in fewer opt-outs by eligible customers.

12. DEC's request that the agreement approved by the Commission in its November 8, 2011 Order Approving DSM/EE Rider and Requiring Filing of Proposed Customer Notice in Docket No. E-7, Sub 979, regarding the application of evaluation, measurement, and verification (EM&V) results (EM&V Agreement), continue to apply to the new portfolio of programs is reasonable and should be approved.

13. DEC's request that the agreement approved by the Commission in its July 16, 2012 Order Adopting Program Flexibility Guidelines in Docket No. E-7, Sub 831, regarding the flexibility to make program changes (Flexibility Guidelines), continue to apply to the new portfolio of programs is reasonable and should be approved.

14. DEC's request that the agreement approved by the Commission in its February 8, 2011 Order Adopting "Decision Tree" to Determine "Found Revenues" and Requiring Reporting in DSM/EE Cost Recovery Filings in Docket No. E-7, Sub 831, regarding the determination of found revenues (Sub 831 Found Revenues Order), continue to apply to the new portfolio and Mechanism is reasonable and should be approved.

15. The purpose of the stipulated Mechanism is (a) to allow DEC to recover all reasonable and prudent costs incurred for adopting and implementing new DSM and new EE measures and programs in accordance with G.S. 62-133.9, Commission Rules R8-68 and R8-69, and the additional principles contained in the Mechanism; (b) to establish certain requirements, in addition to those of Commission Rule R8-68, for requests by DEC for Commission approval of DSM and EE programs; and (c) to establish the terms and conditions for the recovery of Net Lost Revenues and for a Portfolio Performance Incentive (PPI) to reward DEC for adopting and implementing new DSM and EE measures and programs based on the sharing of dollar savings achieved by those measures and programs, and for an additional bonus incentive to reward exceptional EE achievement, if the Commission deems such recovery and reward appropriate.

16. The incentives proposed by the Stipulating Parties, including Net Lost Revenues, the PPI, and the additional bonus incentive, subject to the restrictions set forth in the Mechanism and continuing review for reasonableness, are reasonable and appropriate.

17. The Stipulating Parties shall review the terms and conditions of the Mechanism every four years and shall submit any proposed changes to the Commission for approval; provided, however, that a Stipulating Party may request the Commission to initiate such a review at any time within the four-year period. During the review, the Mechanism shall remain in effect until further order of the Commission revising the terms of the Mechanism or taking such other action as the Commission may deem appropriate.

18. The Company and Public Staff will study the issue of the appropriate avoided transmission and distribution (T&D) costs to be used in the Company's calculations of cost-effectiveness and, if any adjustment is determined to be appropriate, the proposed adjustment will be filed in the Company's 2014 DSM/EE rider proceeding to be made on a prospective basis. However, for purposes of the Mechanism, the Company's initially proposed avoided T&D cost rates are reasonable for Vintage Year 2014. The Company and the Public Staff will jointly review the proposed avoided T&D cost rates for Vintage Year 2015. However, the Company and the Public Staff have agreed that if the review of the avoided T&D rates results in a change of less than 2% from the rates used in this proceeding, no further adjustment is required.

19. The reasonable and prudent Rider 5 Vintage Year 2014 prospective billing factor for residential customers is an increment of 0.2779 cents per kilowatt-hour (kWh) (including gross receipts tax and regulatory fee).

20. The reasonable and prudent Rider 5 Vintage Year 2014 EE prospective billing factor for non-residential customers who do not opt out of Vintage Year 2014 of the Company's EE programs is an increment of 0.0963 cents per kWh (including gross receipts tax and regulatory fee).

21. The reasonable and prudent Rider 5 Vintage Year 2014 DSM prospective billing factor for non-residential customers who do not opt out of Vintage Year 2014 of the Company's DSM programs is an increment of 0.0797 cents per kWh (including gross receipts tax and regulatory fee).

22. Based on all of the evidence, the provisions of the Stipulation and Mechanism are just and reasonable to all parties to this proceeding, serve the public interest, and the Stipulation and Mechanism should be approved in its entirety.

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

These findings of fact are essentially informational, procedural, and jurisdictional in nature and are uncontroverted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The evidence for this finding of fact is contained in the Application, the testimony and exhibits of DEC witnesses Duff, McManeus, and Stevie, Public Staff witnesses Floyd and Maness, and the Stipulation.

No party to this proceeding presented testimony or arguments in opposition to the Stipulation. In addition, NC WARN in its Brief states that it does not object to the Mechanism as outlined in the Stipulation. Nonetheless, as the Stipulation was not adopted by all of the parties to this proceeding, its acceptance by the Commission is governed by the standards set out by the North Carolina Supreme Court in State ex rel. Utils. Comm'n v. Carolina Util. Customers Ass'n, Inc., 348 N.C. 452, 500 S.E.2d 693 (1998) (CUCA I), and State ex rel. Utils. Comm'n v. Carolina Util. Customers Ass'n, Inc., 351 N.C. 223, 524 S.E.2d 10 (2000) (CUCA

II). 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 the Company and the Public Staff witnesses regarding the underlying terms and benefits of the Stipulation. DEC witness Duff testified that the Company initially proposed a new DSM/EE cost recovery mechanism in the form of a cost plus model that provided for the recovery of program costs, net lost revenues incurred for up to 36 months of a measure's life, and a tiered performance incentive based on the cost-effectiveness of the Company's DSM/EE portfolio as determined under the UCT.

Public Staff witness Maness explained the Public Staff's concerns with the Company's proposed cost recovery mechanism as it was presented in DEC's Application. First, the Public Staff contended that the margins over program costs proposed by DEC were in excess of what is necessary and reasonable to incentivize the Company to vigorously pursue cost-effective DSM and EE resources. He also noted that due to the use of program costs as the base to which the incentive percentages are applied, the incentives produced by the proposed mechanism were not sufficiently calibrated or sensitive to fluctuations in the net DSM and EE savings that might be experienced by the Company. As an alternative, witness Maness initially proposed an incentive calculation that would produce the level of shared savings (8% for DSM and 13% for EE) currently allowed for Duke Energy Progress, Inc. and Virginia Electric and Power Company d/b/a Dominion North Carolina Power. In the Stipulation, the Stipulating Parties ultimately agreed on a blended DSM and EE shared savings level of 11.5%. Witness Maness noted that this is a higher shared savings percentage than he recommended in his prefiled testimony. However, the Public Staff decided that this was a reasonable compromise based on DEC's willingness to forego the save-a-watt approach and agree to the shared savings Mechanism.

Public Staff witness Maness testified that the Stipulation is the result of discussions and negotiations among the Stipulating Parties. He stated that it reflects a compromise between the position taken by DEC in its Application and the position taken by the Public Staff in its prefiled direct testimony. He also stated that the Public Staff believes the terms of the Stipulation are reasonable, beneficial, and supportive of the implementation of cost-effective DSM and EE programs by DEC.

The Commission finds and concludes that the Stipulation is the product of the give-and-take of settlement negotiations between DEC, the Public Staff, and the other Stipulating Parties in an effort to appropriately balance the benefits provided to customers by cost-effective DSM and EE programs with proper cost recovery and reasonable incentives that will enable and encourage DEC to produce significant DSM and EE savings.

In addition, the Commission gives significant weight to the fact that the Stipulation adopts a very different approach to the calculation of performance incentives, a shared savings approach, compared to the approach proposed in the Company's Application, which calculates a tiered performance incentive as a margin over program costs based on the cost-effectiveness of the Company's DSM/EE portfolio as determined under the UCT. This significant difference in the Application and the Stipulation demonstrates that the Stipulation is the product of the give-and-take of settlement negotiations between DEC, the Public Staff, and the other Stipulating Parties.

Based on the foregoing, the Commission concludes that the Stipulation is material evidence and should be given substantial weight in this proceeding.

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

The evidence for these findings of fact is contained in the testimony and exhibits of DEC witnesses Duff and Stevie and Public Staff witness Floyd.

Company witness Duff described the portfolio of DSM/EE programs submitted by the Company for Commission approval in this proceeding.

Residential Programs

The Appliance Recycling Program promotes the removal and responsible disposal of inefficient refrigerators and freezers by providing incentives to residential customers. The program is estimated to be cost-effective under the UCT, the TRC test, and the Ratepayer Impact Measure (RIM) test.[1]

[1] The UCT compares utility benefits (avoided energy and capacity related costs) to utility costs incurred to implement the program, such as administration, marketing, customer incentives, and measure offset costs, and does not consider other benefits such as participant savings or societal impacts. This test compares the cost (to the utility) to implement the measures with the savings or avoided costs (to the utility) resulting from the change in magnitude

The Energy Assessments Program assists residential customers by assessing their energy usage and providing recommendations for more efficient use of energy in their homes. The program also directs customers who could benefit from other Company EE and DSM programs to those programs. This program includes Home Energy House Call, which provides eligible customers a free in-home assessment by an energy specialist that identifies specific actions the customers can take to increase their home efficiency, as well as an Energy Efficiency Starter Kit with a variety of measures that can be directly installed by the energy specialist. The program is estimated to be cost-effective under the UCT and the TRC test, but not under the RIM test.

The Energy Efficiency Education Program educates students in grades K-12 about energy and the impact they can have by becoming more energy efficient and using energy more wisely. The Company provides educational materials and curriculum for targeted schools and grades, enhances the message with a live theatrical production, and reinforces the message with classroom and take-home assignments. Upon completion of an energy survey, students receive an Energy Efficiency Starter Kit so they can implement energy saving measures in their homes. The program is estimated to be cost-effective under the UCT and the TRC test, but not under the RIM test.

The Energy Efficient Appliances and Devices Program provides incentives to residential customers for installing energy efficient appliances and devices to drive reductions in energy usage. The program includes the following measures: Energy Efficient Pool Equipment (initially focusing on variable speed pumps for pools), Energy Efficient Lighting (a wide range of energy efficient lighting products and controls), Energy Efficient Water Heating and Usage (heat pump water heaters, insulation, temperature cards, and low flow devices), and Other Energy Efficiency Products and Services (other cost-effective measures that may be added to in-home installations, purchases, enrollments, and events). The program is estimated to be cost-effective under the UCT and the TRC test, but not under the RIM test.

The Heating, Ventilation, and Air Conditioning (HVAC) Energy Efficiency Program provides maintenance and improvements to residential customers' central HVAC system(s), as well as the structure of the building envelope and duct system(s) of their homes. The measures include central air conditioners, heat pumps, attic insulation and air

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and/or the pattern of electricity consumption caused by implementation of the program. Avoided costs are considered in the evaluation of cost-effectiveness based on the projected cost of power, including the projected cost of the utility's environmental compliance for known regulatory requirements. The cost-effectiveness analyses also incorporate avoided T&D costs, and load (line) losses.

The TRC test compares the total benefits to the utility and participants relative to the costs to the utility to implement the program along with the costs to the participant. The benefits to the utility are the same as those computed under the UCT. The benefits to the participant are the same as those computed under the Participant Test; however, customer incentives are considered to be a pass-through benefit to customers. As such, customer incentives or rebates are not included in the TRC.

The RIM Test, or non-participants test, indicates if rates increase or decrease over the long-run as a result of implementing the program.

sealing, duct sealing, duct insulation, central air conditioner tune up, and heat pump tune up. The program is estimated to be cost-effective under the UCT, the TRC test, and the RIM test.

The Multi-Family Energy Efficiency Program provides energy efficient technologies to be installed in multi-family dwellings, including energy efficient lighting and water heating measures, as well as other cost-effective measures that may be added. The program is estimated to be cost-effective under the UCT and the TRC test, but not under the RIM test.

The My Home Energy Report Program provides residential customers with a comparative usage report up to 12 times a year that compares their energy use to similar residences in the same geographical area based upon the age, size, and heating source of the home. The report also provides participants with specific energy saving recommendations to improve the efficiency of their homes. The program is estimated to be cost-effective under the UCT and the TRC test, but not under the RIM test.

The Income-Qualified Energy Efficiency and Weatherization Program consists of three components:

The Residential Neighborhood Program (RNP) is available only to individually metered residences in low-income neighborhoods selected by the Company. Neighborhoods targeted for participation in this program will typically have approximately 50% or more of the households with income up to 200% of the poverty level established by the U.S. Government. The program provides customers with the direct installation of measures into the home to increase the EE and comfort level of the home. Additionally, customers receive EE education to encourage behavioral changes for managing energy usage and costs. The RNP may not meet the needs of some customers who need assistance that is more substantial. Consequently, the Company will also offer two programs that piggy-back on the existing government-funded North Carolina Weatherization Assistance Program when feasible, in order to reduce overhead and administrative costs.

The Weatherization and Equipment Replacement Program (WERP) offers weatherization services and equipment replacement for electric heating systems to individually metered, single-family residences that meet the income eligibility standards for the North Carolina Weatherization Assistance Program.

The Refrigerator Replacement Program (RRP) includes the replacement of inefficient operable refrigerators in low-income households and will be available to homeowners, renters, and landlords with income qualified tenants that own a qualified appliance. Like the WERP, income eligibility for RRP will mirror the income eligibility standards for the North Carolina Weatherization Assistance Program.

The Income-Qualified Energy Efficiency and Weatherization Program is estimated to be cost-effective under the TRC test, but not under the UCT or the RIM test.

Power Manager is an existing voluntary demand response program that, to reduce electricity demand, limits the run time of participating customers' central air conditioning (cooling) systems by completely interrupting service to or cycling of the cooling system. Customers receive bill credits during the billing months of July through October for participation.

Non-Residential Programs

The Non-Residential Smart $aver® Energy Efficient Food Service Products Program provides prescriptive incentive payments to encourage and partially offset the cost of the installation of new high efficiency food service equipment and the repairs to maintain or enhance efficiency levels in currently installed equipment. Measures include, but are not limited to, commercial refrigerators and freezers, steam cookers, pre-rinse sprayers, vending machine controllers, and anti-sweat heater controls. The program is estimated to be cost-effective under the UCT, the TRC test, and the RIM test.

The Non-Residential Smart $aver® Energy Efficient HVAC Products Program provides prescriptive incentive payments to encourage and partially offset the cost of the installation of new high efficient HVAC equipment and the efficiency directed repairs to maintain or enhance efficiency levels in currently installed equipment. Measures include, but are not limited to, chillers, unitary and rooftop air conditioners, programmable thermostats, and guest room energy management systems. The program is estimated to be cost-effective under the UCT, the TRC test, and the RIM test.

The Non-Residential Smart $aver® Energy Efficient IT (Information Technologies) Products Program provides prescriptive incentive payments to encourage and partially offset the cost of the installation of high efficiency new IT equipment and the efficiency-directed repairs to maintain or enhance efficiency levels in currently-installed equipment. Measures include, but are not limited to, Energy Star-rated desktop computers and servers, and PC power management from network, server virtualization, and variable frequency drives (VFDs). The program is estimated to be cost-effective under the UCT and the TRC test, but not under the RIM test.

The Non-Residential Smart $aver® Energy Efficient Lighting Products Program provides prescriptive incentive payments to encourage and partially offset the cost of the installation of new high efficiency lighting equipment and the efficiency-directed repairs to maintain or enhance efficiency levels in currently installed equipment. Measures include, but are not limited to, interior and exterior LED lamps and fixtures, reduced wattage and high performance T8 systems, T8 and T5 high bay fixtures, and occupancy sensors. The program is estimated to be cost-effective under the UCT, the TRC test, and the RIM test.

The existing Non-Residential Smart $aver® Energy Efficient Process Equipment Products Program provides prescriptive incentive payments to encourage and partially offset the cost of the installation of new high efficiency equipment and the efficiency-directed repairs to maintain or enhance high efficiency levels in currently installed equipment. Measures include, but are not limited to, VFD air compressors, barrel wraps, and pellet dryer insulation. The program is estimated to be cost-effective under the UCT, the TRC test, and the RIM test.

The existing Non-Residential Smart $aver® Energy Efficient Pumps and Drives Products Program provides prescriptive incentive payments to encourage and partially offset the cost of the installation of new high efficiency equipment and the efficiency-directed repairs to maintain or enhance efficiency levels in currently installed equipment. Measures include, but are not limited to, pumps and VFD on HVAC pumps and fans. The program is estimated to be cost-effective under the UCT, the TRC test, and the RIM test.

The Non-Residential Smart $aver® Custom Program provides custom incentives in the amount of up to 75% of the installed cost difference between standard equipment and new higher efficiency equipment or efficiency-directed repair activities in order to cover measures and efficiency-driven activities that are not offered in the various Non-Residential Smart $aver prescriptive programs. The program is estimated to be cost-effective under the UCT, the TRC test, and the RIM test.

The Non-Residential Smart $aver® Custom Energy Assessments Program provides customers with a custom incentive payment in the amount of up to 50% of the costs of a qualifying energy assessment to offset the upfront costs of identifying and evaluating EE projects. The energy assessment may include a facility energy audit, a new construction/renovation energy performance simulation, a system energy study, and retro-commissioning service. After the energy assessment is complete, program participants may receive an additional custom incentive payment of up to 75% of the installed cost difference between standard equipment and higher efficiency equipment or efficiency-directed repair activities. The program is estimated to be cost-effective under the UCT, the TRC test, and the RIM test.

The existing PowerShare® Program provides billing credits for customers that chose a mandatory option under which they receive a capacity and energy credit, or a voluntary option under which they receive an energy credit for load curtailed.

The existing PowerShare® CallOption Program provides additional versatility to the regular PowerShare® Program by offering five enrollment options to customers that limit the number of emergency events to five and also limit the number of economic events.

Pilot Program

The Company also proposed an Energy Management and Information Services Pilot, which will provide commercial or institutional customer facilities with energy management and information system software that provides interval meter data and remote or light on-site energy assessments focused on low-cost operational EE measures. The customer will also implement a bundle of low cost operational and maintenance-based energy efficient measures that meet certain financial investment criteria. The program is estimated to be cost-effective under the UCT, but not under the TRC and the RIM test.

Company witness Duff explained that each of these programs is "new" under G.S. 62-133.9 and Commission Rule R8-68 as each is either a program that was approved by the Commission as a "new" program during the save-a-watt pilot (and may have been subsequently modified) or is a new program that the Company has not previously implemented. For each program, the Company provided the information on the costs and benefits of each proposed measure or program required by Commission Rule R8-68(c), including the estimated total and per unit cost and benefit of the measure or program reported by type of benefit and expenditure, the type, maximum and minimum amount of participation incentives, cost information on communications materials, and the results of all cost-effectiveness tests.

The Company originally proposed that the portfolio of programs have a term of four years. Public Staff witness Floyd recommended that the programs have an indefinite term. Pursuant to the Stipulation, the Stipulating Parties agreed that the programs would have an indefinite term.

Company witness Stevie, adopting the testimony of witness Ossege, described DEC's method of evaluating, measuring, and verifying the impacts achieved from the proposed new portfolio of DSM and EE programs. He also discussed the cost-effectiveness tests for the new portfolio. Witness Stevie testified that DEC estimates that 5% of total program costs will be required to perform EM&V for the proposed portfolio, which is within the historical industry experience of evaluation costs (typically 3% to 8% of total program spending). The Company provided the projected schedules and effective dates for EM&V in Ossege Exhibit 2.

Witness Duff described the quarterly meetings that DEC holds with interested stakeholders, including the Public Staff, the South Carolina Office of Regulatory Staff, SACE, and other environmental groups (Collaborative). He stated that these meetings provide the Company with an opportunity to communicate with Collaborative members on a regular basis regarding program performance and EM&V activity, and also to solicit feedback regarding program additions and potential program improvements. Witness Duff noted that the Collaborative has allowed the Company to gain stakeholder support, eliminate opposition to filings, and provide a valuable forum for the Company to consider a variety of perspectives.

Witness Duff also testified about the Company's latest EE Study. He indicated that the total technical potential identified by the EE Study over the 20-year horizon ranges between 29% and 35% depending on whether or not impacts from photovoltaic-related programs are included. He noted that the report finds that while it is technically possible to cut usage and demand significantly, the estimates are unconstrained by market, behavioral, and budget considerations. The EE Study also presents the economic potential by developing a DSM supply curve reflecting the direct relationship between the long-term marginal cost of energy supply and energy efficiency potential. The EE Study included a Five Year Action Plan, which projected a cumulative achievable savings potential of 497.9 million kWh, less than 55% of the 909.5 million kWh projected to be achieved by the Company's proposed portfolio over the same overlapping three-year period.

In its Brief, NC WARN stated its concern that the demand reduction commitments that DEC has made through its EE and DSM programs have not been reflected in its future planning. NC WARN observed that DEC's DSM and EE goals are crucial components of the Company's long term planning. In particular, they play a significant role in future forecasts of demand and the need for new generation. NC WARN asserted that under G.S. 62-2(3a) and 62-133.9(b), one of the requirements for recovery of the costs of the EE/DSM programs is the development of those programs in concert with achieving a balance between demand reduction and generation. Thus, NC WARN submitted that the Commission should require DEC to use its long-term reduction goals in its future Integrated Resource Plans (IRPs). The Commission concludes that the appropriate balance to be given DSM and EE in DEC's demand forecasts and planning is an issue for discussion in future IRP proceedings, rather than in the present proceeding.

With the exception of NC WARN's proposals regarding the Multi-Family EE and Income-Qualified EE and Weatherization Programs as discussed below, no party opposed the Company's proposed portfolio of programs. The Stipulation provides that the portfolio of DSM and EE programs should be approved as filed, except the programs should be approved without a specific term and with a clarification regarding CHP as discussed below. The Commission finds that because the proposed programs are generally cost-effective, and encourage EE and DSM, the programs are all in the public interest and, as such, should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The evidence for this finding of fact is contained in the testimony and exhibits of DEC witness Duff and NC WARN witnesses DeBerry and Warren.

NC WARN witness Warren presented testimony regarding ways in which the Company's proposed Multi-Family EE Program (Multi-Family Program) could achieve greater energy savings. She proposed that the multi-family program offer additional measures such as ventilation improvements, programmable thermostats, motors and VFDs, HVAC upgrades, air sealing, and drain-water heat recovery. She did not present any data regarding the costs, benefits, or cost-effectiveness of these additional measures.

In response to NC WARN witness Warren's testimony regarding the Multi-Family Program, DEC witness Duff stated that the Company does not disagree that multi-family housing is an attractive segment of the market that offers the opportunity to deliver EE. He pointed out that witness Warren's testimony lacked specific analysis to back up her assertions, such as her claim that the comprehensive approach she advocates can be implemented in a cost-effective manner. He stated that the Company's proposed Multi-Family Program would provide new opportunities for eligible customers to achieve cost-effective EE. Further, he invited witness Warren to join the Collaborative and indicated that the Company would welcome the opportunity to discuss with her how the proposed Multi-Family Program might be improved or expanded to include additional measures.

NC WARN witness DeBerry described a Community-Enhanced Program that she and NC WARN proposed to replace the Company's Income-Qualified EE and Weatherization Program. She noted that the primary differences between the two programs were the administration of the funds and the use of existing community-based organizations. Her proposed Community-Enhanced Program would be administered by the NCHFA, a quasi-governmental body that currently has contracts in place with local governments, community action agencies, community development corporations, and nongovernmental organizations in each county in North Carolina. As the agency already has a backlog of clients who qualify for weatherization services, it would be unnecessary to market the program to new clients. Witness DeBerry also explained that the proposed Community-Enhanced Program would result in additional jobs in the served communities. One-third of the funds for the Community-Enhanced Program would be reserved for community educational programs. Her proposal contained a description of the program, including a proposal to increase the annual expenses of the program by 150%, from the $12 million proposed by the Company to $30 million, but lacked any detail as to the costs, benefits, or cost-effectiveness. However, witness DeBerry contended that the Community-Enhanced Program is cost-effective.

In response to NC WARN witness DeBerry's proposal of a Community-Enhanced Program administered by the NCHFA to replace the Company's Income-Qualified EE and Weatherization Program, DEC witness Duff noted that the Community-Enhanced Program proposed by NC WARN lacked the necessary measure level detail or even specific energy savings impact information to be compared to the Company's proposed program, which met the filing requirements of Commission Rule R8-68(c). He testified that the Company has an established low-income weatherization program designed to complement and be coordinated with the weatherization efforts of the North Carolina State Energy Office. He indicated that the Company did not believe that there was justification to shift funding from the State Energy Office to the NCHFA. On redirect, witness Duff noted that the State Energy Office coordinates its weatherization efforts through community-based organizations such as that represented by public witness McKee-Huger. He also pointed out that the Company uses local vendors or trade allies, who work with community, neighborhood, and faith-based organization leaders to assist in informing potential participants about the neighborhood low-income EE programs. He agreed with witness DeBerry that community based low-income agencies can provide value to low-income customers in the Company's service territory. He invited her to join the Collaborative and indicated that the Company would welcome the opportunity to discuss with her how its proposed Income-Qualified EE and Weatherization Program might be improved or expanded. He also discussed the Company's Ohio affiliate's low-income weatherization pilot program that uses a "pay for performance" model through which a community action agency is able to attract additional funding and provide more extensive weatherization services more cost-effectively. Witness Duff indicated that he would discuss this Ohio program with NC WARN.

NC WARN did not join as a party to the Stipulation. However, the Stipulating Parties included a provision in the Stipulation stating that the Company will meet with NC WARN and other interested intervenors to discuss the low-income program proposed by NC WARN, with the intent of developing a program to present to the Collaborative for discussion and refinement, and possibly filing such a low-income program with the Commission.

In its Brief, NC WARN reiterated its position that the Community-Enhanced Program for low-income households proposed by NC WARN is a cost-effective alternative to the low-income program proposed by DEC. It noted that the most important differences in its proposal and DEC's program are the administration of the funds by NCHFA and the use of existing community-based organizations. NC WARN stated that NCHFA has an infrastructure in place and has a solid reputation as a dependable fiscal agent. In addition, NCHFA has existing contracts with local governments, community action agencies, community development corporations and nongovernmental organizations, such as urban ministries, in each of the 100 counties in North Carolina. With regard to improvements in DEC's Multi-Family Program, NC WARN submitted that this program could be strengthened by expanding the measures to include ventilation improvements, programmable thermostats, motors, HVAC upgrades, air sealing and drain-water heat recovery.

The Commission finds that the proposals submitted by NC WARN regarding the alternatives to the Company's proposed Multi-Family and the Income-Qualified EE and Weatherization Programs have merit in their use of community action agencies and the potential for job creation. However, the Commission agrees with the Company that NC WARN's proposed programs lack the specificity required under Commission Rule R8-68 for program approval. The Commission is of the opinion that the appropriate next step for these proposals is consideration in the Collaborative. The Commission believes the Stipulation has appropriately provided for further consideration and possible development of a low-income program similar to that proposed by NC WARN. Further, the Company has invited NC WARN's witness Warren and others to the Collaborative to discuss their proposals regarding multi-family housing and other low-income programs. The Commission finds and concludes that the Company should report on the status of the discussions regarding the low-income and multi-family programs in its next DSM/EE rider filing.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The evidence for this finding of fact is contained in the testimony and exhibits of NCSEA and EDF witnesses Panzarella and Copithorne.

NCSEA and EDF witness Copithorne testified regarding on-bill repayment (OBR), which allows property owners to finance EE improvements with capital provided by non-utility third-party investors, often at lower interest rates because the loan is tied to the customer's utility bill. He proposed that the Commission encourage the discussion of the topic of commercial and industrial OBR in the Company's Collaborative, with a report of the discussions to the Commission.

NCSEA and EDF witness Panzarella testified regarding CHP, which he explained is an energy efficient technology that can reduce businesses' overall energy costs and reduce the utility's need for additional generation, transmission, and distribution. He explained that optimally-efficient topping-cycle CHP systems are typically designed and sized to meet a facility's baseload thermal demand, while bottoming-cycle CHP systems, also referred to as waste-heat-to-power, take advantage of heat that is generated as part of an industrial process and normally vented to the atmosphere. He proposed that the Commission encourage the Company to introduce CHP as a topic for discussion in the Collaborative, with a report of the discussions to the Commission. Witness Panzarella also contended that the tariffs of the proposed Non-Residential Smart $aver® Custom Program and Non-Residential Smart $aver® Custom Energy Assessments Program appear to exclude CHP.

Pursuant to the Stipulation, the Company agreed to clarify that its proposed Non-Residential Smart $aver® Custom Program and the Non-Residential Smart $aver® Custom Energy Assessments Program do not exclude bottoming-cycle CHP or the waste-heat recovery components of topping-cycle CHP. The Stipulation also provides that the Collaborative will commence discussing and considering OBR and CHP by December 31, 2013. The Company has agreed to report to the Commission the status of these discussions in its next and subsequent DSM/EE rider filings. No party opposed these provisions of the Stipulation. The Commission finds that these provisions are reasonable and appropriate and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The evidence for this finding of fact is contained in the testimony of DEC witnesses Duff and McManeus, the testimony of Public Staff witnesses Floyd and Maness, and the Stipulation.

DEC requested in its Application (a) waiver of Commission Rule R8-69(d)(3) to allow the Company more flexibility in implementing and managing the opt-out elections of individual commercial customers with annual energy usage of not less than 1,000,000 kWh and industrial customers, as set forth in the Sub 938 Waiver Order and (b) waivers of Commission Rules R8-69(a)(4) and R8-69(a)(5) as approved in the Sub 938 Second Waiver Order. In the Sub 938 Waiver Order, the Commission approved, in part, DEC's request for waiver of Commission Rule R8-69(d)(3), thereby allowing the Company to permit qualifying non-residential customers[1] to opt out of the DSM and/or EE portion of Rider EE during annual enrollment periods. If a customer opts into a DSM program (or never opted out), it is required to participate for three years in the approved save-a-watt DSM programs and rider. If a customer chooses to participate in an EE program (or never opted out), that customer is required to pay the EE-related avoided cost revenue requirements and the net lost revenues for the corresponding vintage of the programs in which it participated. Customers that opt out of the Company’s DSM and/or EE programs would remain opted-out for the term of the save-a-watt pilot, unless they choose to opt back in during any of the succeeding annual election periods, which occur from November 1 to December 31 each year. If a customer participates in any vintage of programs, the customer is subject to all true-up provisions of the approved Rider EE for any vintage in which the customer participates.

Company witness Duff explained that DEC believes that asking the Commission again to grant the Company a waiver to allow for the separation of EE and DSM programs for the purpose of eligible customers making their annual opt-out election is a key way to encourage customer participation. The continuation of this waiver will give customers the necessary flexibility achieved by not requiring them to opt out of both the DSM and EE components. This will allow more opt-out eligible customers to choose to participate in either DSM or EE. Witness Duff also detailed how the Company is requesting to add a week-long “opt-in period” for customers who had previously elected to opt out in the annual enrollment period. Under this proposal, during the first week of March (five business days), the Company would allow opted-out customers to elect to opt in and participate in EE and/or DSM programs during the

[1] Individual commercial customer accounts with annual energy usage of not less than 1,000,000 kWh and any industrial customer account.

remainder of the vintage year. Witness Duff stated that the Company believes that allowing eligible customers this additional election period to consider participating in EE and/or DSM programs after some customers' fiscal years have begun could potentially decrease the number of customers electing to opt out, since the opt-out elections are required before some customers have finalized their capital budgets for the next year.

Public Staff witness Maness testified that the Stipulation provides that the current Commission practice of calculating separate DSM and EE billing factors for the Non-Residential class, pursuant to the Commission's Orders in Docket No. E-7, Sub 938, shall continue. Furthermore, the "General Structure of Riders" section of the Mechanism, Paragraph 43, states that the Non-Residential DSM and EE EMF billing factors shall be determined separately for each vintage year appropriately considered in each proceeding, so that the factors can be appropriately charged to Non-Residential customers based on their opt-in/out status and participation for each vintage year.

No party opposed the Company's request for waivers of Commission Rules R8-69(d)(3), R8-69(a)(4), and R8-69(a)(5). These waivers previously have been granted by the Commission under the modified save-a-watt Mechanism in order to allow the Company to follow the protocol of separately billing non-opted-out Non-Residential customers, by vintage year, in accordance with their individual opt-out/in status and participation each vintage year in DSM and/or EE programs. The Commission concludes that the continuation of this billing approach and structure is appropriate and reasonable, in that it may result in fewer opt-outs by eligible customers. Accordingly, the Commission finds that the requested waivers are reasonable and appropriate and should be granted, and that the billing approach and protocol approved by the Commission in Docket No. E-7, Sub 938 should continue to be implemented as part of DEC's new Mechanism.

With regard to the Company's proposal to add a five-business-day opt-in period during the first week in March of each year, Public Staff witness Floyd supported the Company's efforts to encourage opted-out customers to opt-in. In addition, Paragraph 37 of the Mechanism indicates that the Stipulating Parties have agreed to this proposal, as confirmed by the testimony of witness Maness. The Commission concludes that the additional opt-in period may encourage certain previously opted-out customers to opt back in and participate in the Company's programs. Therefore, the Commission approves the request by the Company and the waiver of the Commission's Rules necessary to accomplish this objective.

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

The evidence for these findings of fact is contained in the testimony and exhibits of DEC witnesses Duff and Stevie, Public Staff witnesses Floyd and Maness, and the Stipulation.

DEC witnesses Duff and Stevie testified regarding the EM&V Agreement. Under the EM&V Agreement, for purposes of the annual true-ups, initial results based upon the Carolinas EM&V would be considered actual results for a program and would continue to apply until superseded by new EM&V results, if any. For all new programs and pilots that do not have existing Carolinas-based EM&V approved in this portfolio, the initial estimates of impacts will be used until DEC has EM&V results, which will then be applied retrospectively to the beginning of the offering and will be considered actual results until a second EM&V is performed, which will then be applied prospectively beginning from the EM&V sample analysis end date. All program impacts from EM&V apply only to the programs for which the analysis was directly performed. The Company requests that the EM&V Agreement continue to apply with its new portfolio of programs. The Public Staff supports the continued application of the EM&V Agreement, as reflected in the Stipulation. No party opposed this request. The Commission finds that it is appropriate to continue to apply the EM&V Agreement.

In its November 8, 2011 Order Approving DSM/EE Rider and Requiring Filing of Proposed Customer Notice issued in Docket No. E-7, Sub 979, the Commission directed the Company, the Public Staff, and SACE to discuss revisions to the program flexibility guidelines approved in the February 26, 2009 Order Resolving Certain Issues, Requesting Information on Unsettled Matters, and Allowing Proposed Rider to Become Effective Subject to Refund in Docket No. E-7, Sub 831 (First Save-a-Watt Order) and file a joint proposal. The parties developed and filed a Joint Proposal for the establishment of Program Flexibility Guidelines with the Commission (Flexibility Guidelines) on February 6, 2012, which was approved by the Commission in its July 16, 2012 Order Adopting Program Flexibility Guidelines in Docket No. E-7, Sub 831. These Flexibility Guidelines classified types of program changes and then determined whether Commission approval, notice, or a subsequent quarterly report was required. The Company requests that the Flexibility Guidelines continue to apply to its new portfolio of programs. The Public Staff supports the continued application of the Flexibility Guidelines, as reflected in the settlement testimony of witness Maness and in the Stipulation. No party opposed this request. The Commission finds that it is appropriate to continue to apply the Flexibility Guidelines.

Company witness Duff testified that in the First Save-a-Watt Order the Commission directed the Company to factor the impact of activities undertaken by the Company that would directly or indirectly result in an increase in customer demand or energy consumption within DEC's service territory – *i.e.*, “found revenues” – into the calculation of net lost revenues to be recovered under Rider EE. While the Company understood this requirement, there was ambiguity around what activities should actually be tracked and factored into the calculation of net lost revenues. To resolve this ambiguity, the Public Staff and DEC developed a Found Revenues Decision Tree (Decision Tree) to identify, categorize, and net possible found revenues against the net lost revenues created by the Company’s EE programs. The Decision Tree was subsequently approved by the Commission in its February 8, 2011 Order Adopting “Decision Tree” to Determine “Found Revenues” and Requiring Reporting in DSM/EE Cost Recovery Filings in Docket No. E-7, Sub 831 (Sub 831 Found Revenues Order). Witness Duff stated that it has made the successive annual Rider EE filings less contentious and easier as all parties have clarity regarding how found revenues are to be determined.

Company witness Duff further testified that DEC was requesting that the Decision Tree continue to be utilized for the purposes of recognizing found revenues in the calculation of net lost revenues. He stated that the continued utilization of the Decision Tree would ensure that the Company continues to recognize the appropriate activities that increase sales and apply these impacts against the lost revenues associated with EE impacts.

Public Staff witness Maness testified that the Public Staff agrees with the Company's proposal to continue to use the Decision Tree to determine found revenues, and that provisions for this continued use are included in the Stipulation. Therefore, the Commission concludes that the Company's proposal that the Decision Tree approach continue to be used in the determination of found revenues associated with the new portfolio and Mechanism is reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 15-17

The evidence for these findings of fact is contained in the testimony and exhibits of DEC witnesses Duff and McManeus, the testimony of Public Staff witness Maness, and the Stipulation.

As described by DEC witness Duff, the Company initially proposed a new DSM/EE cost recovery mechanism in the form of a cost plus model that provided for the recovery of program costs, net lost revenues incurred for up to 36 months of a measure's life, and a tiered performance incentive based on the cost-effectiveness of the Company's DSM/EE portfolio as determined under the UCT. Witness Duff indicated that the proposed incentive mechanism was designed around four main tenets: (a) it should provide transparency regarding the amount of incentive the Company is eligible to earn and actually earns in a given year; (b) it should tie the incentive recovered through the mechanism to how the Company performs related to variables and performance that the Company can control; (c) it should encourage the Company to be a good steward of customer dollars, instead of rewarding the Company for spending more; and (d) it should both motivate the Company to achieve EE and DSM impacts in the most cost-effective manner and to offer all cost-effective EE and DSM programs.

Public Staff witness Maness explained the Public Staff's concerns with the Company's proposed cost recovery mechanism. First, the Public Staff contended that the margins over program costs proposed by the Company were in excess of what is necessary and reasonable to incentivize the Company to vigorously pursue cost-effective DSM and EE resources. He also noted that due to the use of program costs as the base to which the incentive percentages are applied, the incentives produced by the proposed mechanism were not sufficiently calibrated or sensitive to fluctuations in the net DSM and EE savings that might be experienced by the Company. Instead, witness Maness initially proposed an incentive calculation that would produce the level of shared savings (8% for DSM and 13% for EE) currently allowed for Duke Energy Progress, Inc. (DEP), and Virginia Electric and Power Company d/b/a Dominion North Carolina Power (DNCP).

Following the filing of intervenor testimony, the Stipulating Parties engaged in negotiations and developed an alternate cost and incentive recovery mechanism. In his settlement testimony, witness Duff explained that the proposed Mechanism provides for the recovery of program costs, net lost revenues for 36 months, and a Portfolio Performance Incentive (PPI) in the form of a shared savings utility incentive. It allows DEC to recover all reasonable and prudent costs incurred for adopting and implementing DSM and EE measures in accordance with G.S. 62-133.9 and Commission Rules R8-68 and R8-69, and rewards the Company through a PPI for adopting and implementing DSM and EE measures and programs based upon the sharing of net savings achieved by those measures and programs. Witness Duff noted that the shared savings mechanism agreed to in the Stipulation is simple and transparent, and should provide the Company with the appropriate incentive to deliver as much EE and DSM as possible cost-effectively.

Witness Duff explained that the Mechanism fulfills the four tenets he explained in his direct testimony presenting the Company’s original proposed cost recovery mechanism. Specifically, the shared savings mechanism is an accepted methodology that provides transparency regarding the amount of incentive the Company is eligible to earn and actually earns in a given year. Second, the Mechanism ties the Company's incentive to metrics that it can control, specifically the Company’s ability to manage program costs and optimize the cost-effectiveness of the portfolio. Third, the Mechanism encourages the Company to spend customers' dollars cost-effectively, as opposed to rewarding it for spending more. The Company has incentive to provide a wide array of DSM and EE opportunities to customers that will attract participation and deliver significant energy and capacity savings, and to operate in the most cost-effective manner. Finally, the Company also has incentive to offer all cost-effective EE and DSM programs.

Witness Duff also testified that the stipulated shared savings percentage of 11.5% is high enough that the returns provided on a less cost-effective portfolio will still provide the Company a meaningful incentive. He also pointed out that by excluding low-income and other non-cost-effective programs from the calculation of savings, the Company's incentive will not be negatively impacted by adding these types of programs, which may not be cost-effective but advance other highly important societal and policy goals. For EE programs that may not be cost-effective, but are desirable for societal and policy reasons, such as low-income weatherization, the Company would be eligible to recover the program costs and up to 36 months of net lost revenues.

Witness Duff explained that under the Mechanism, the PPI is determined by subtracting the net present value of the annual lifetime program costs (excluding those of approved low-income programs) from the net present value of the annual lifetime avoided costs achieved through the Company's programs (excluding approved low-income programs). The net savings eligible for incentive are then multiplied by the 11.5% shared savings percentage to determine the Company's pretax incentive. Pursuant to the Stipulation, as a further incentive to pursue all cost-effective EE programs, the Company will have the ability to earn an additional bonus incentive if it achieves incremental energy savings of 1% of the prior year's retail electric sales in any year during the five-year period, 2014 through 2018. The Stipulation has had no impact on the projected results of the projected EE achievement levels of the Company's proposed portfolio.

Public Staff witness Maness described the sections of the Mechanism as follows:

<u>Term</u>

The Term section provides that the Mechanism shall continue until terminated pursuant to Commission Order.

Application for Approval

The Application for Approval of Programs section sets out the steps and criteria the Company will follow when considering whether or not to propose a DSM or EE program. Witness Maness explained that after a qualitative screening of the measures to determine if they are feasible as a utility DSM/EE program, the Company will screen measures for cost-effectiveness. Except for measures included in low-income programs or other non-cost-effective programs with similar societal benefits as approved by the Commission, DEC will not consider measures with TRC test results less than 1.00.

Program Modifications

The Program Modifications section provides that modifications to Commission-approved DSM/EE programs will be made using the Flexibility Guidelines.

EM&V

The EM&V section provides that EM&V of programs will be performed to ensure that programs remain cost-effective, and that the application of EM&V to programs will follow the terms of the EM&V Agreement.

Opt-Outs

The Opt-Outs section provides that the treatment of opted-out and opted-in customers will continue to be guided by the Commission's Orders in Docket No. E-7, Sub 938. The section also adds an additional opt-in period during the first week in March of each year.

Collaborative

The Collaborative section provides that the existing Collaborative process will continue, with meetings held on a quarterly basis.

General Structure of Riders

The General Structure of Riders section provides for the calculation of the DSM/EE and DSM/EE EMF riders on a vintage year basis, with separate riders for the Residential customer class and for those rate schedules within the Non-Residential customer class that have programs in which they can participate. Additionally, separate DSM and EE billing factors will be calculated for the Non-Residential class, and further subdivided by vintage year.

Cost Recovery

The Cost Recovery section addresses the recovery of program costs as part of the annual riders, and sets forth how such costs will be recovered on both an estimated basis (through the DSM/EE rider) and a trued-up basis (through the DSM/EE EMF rider). Any Stipulating Party may propose a procedure to defer DSM/EE program costs and amortize them over future periods, to the extent those costs are intended to produce future benefits. In addition, deferral accounting for over- and under-recoveries of costs is allowed, and the balance in the deferral account(s), net of deferred income taxes, may accrue a return at the net-of-tax rate of return. The methodology used for the calculation of the return shall be the same as that typically utilized for the Company's Existing DSM Program Rider proceeding (taking into account any extensions of the EMF measurement period pursuant to Commission Rule R8-69(b)(2)). A return on both under- and over-recoveries will be allowed through the EMF collection or refund period. Implementation of this provision as agreed to by the Stipulating Parties in Paragraph 47 of the Stipulation will require a waiver of Commission Rule R8-69(b)(6) to allow the compounding of interest.

Net Lost Revenues

The Net Lost Revenues section of the Mechanism sets forth the criteria that will govern the recovery of Net Lost Revenues as an incentive. It limits the recovery of Net Lost Revenues to the first 36 months after the installation of the measurement unit. Programs for the general awareness and education of EE and DSM activities, as well as research and development activities, are ineligible for the recovery of Net Lost Revenues. To recover Net Lost Revenues for a pilot program, the Company must, in its application for program or measure approval, demonstrate (a) that the program or measure is of a type that is intended to be developed into a full-scale, Commission-approved program or measure, and (b) that DEC will implement an EM&V plan based on industry-accepted protocols for the program or measure. Additionally, no pilot is eligible for Net Lost Revenues recovery unless it is ultimately proven to have been cost-effective and is developed into a full-scale program.

The eligibility of kWh sales reductions to generate recoverable Net Lost Revenues during the applicable 36-month period will cease upon the implementation of a Commission-approved alternative recovery mechanism that accounts for Net Lost Revenues, or new rates approved by the Commission in a general rate case or comparable proceeding. Additionally, Net Lost Revenues will be reduced by net found revenues, determined according to the Decision Tree. Any true-up of Net Lost Revenues will be based on the Commission-approved results of the appropriate EM&V studies related to the program/measure and vintage year. The true-up will be calculated based on the difference between projected and actual recoverable Net Lost Revenues for each measurement unit and vintage year under consideration, accounting for any differences derived from the completed and reviewed EM&V studies, including: (1) the projected and actual number of installations per measurement unit; (2) the projected and actual net kWh and kW savings per installation; (3) the projected and actual gross lost revenues per kWh and kW saved; and (4) the projected and actual deductions from gross lost revenues per kWh and kW saved.

Portfolio Performance Incentive (PPI)

The PPI section of the Mechanism provides for the recovery by DEC of a performance incentive for its DSM and EE portfolio based on the sharing of actually achieved and verified energy and peak demand savings. General programs and measures and research and development activities are not eligible to be included in the determination of the PPI. Pilot programs are also ineligible for a PPI unless the Company requests a PPI at program approval and the pilot is commercialized. Additionally, low-income programs and other non-cost-effective programs with similar societal benefits as approved by the Commission would not be included in the portfolio for purposes of the PPI calculation. The PPI will be based on the system-level net dollar savings of each program or measure as calculated using the UCT, with the net savings properly allocated to the North Carolina retail jurisdiction. The initial pre-income-tax PPI for the entire DSM/EE portfolio for a vintage year will be 11.5% multiplied by the present value of the estimated net dollar savings associated with the DSM/EE portfolio installed in that vintage year. The annual lifetime avoided cost savings for measurement units installed in the applicable vintage year shall be calculated by multiplying the number of each specific type of measurement unit projected to be installed in that vintage year by the most current estimates of each lifetime year's per installation kW and kWh savings and by the most current estimates of each lifetime year's per kW and kWh avoided costs. At the outset of the application of the Mechanism, the entire PPI related to a vintage year shall be recoverable in the rate period covering that vintage year (subject to true-up). However, a Stipulating Party may propose a procedure to convert a vintage year PPI into a stream of levelized annual payments not to exceed 10 years.

For the PPI for Vintage Year 2014, the per kW avoided capacity costs used to calculate avoided cost savings shall be those reflected in the Company’s filing in Docket No. E-100, Sub 136 (Sub 136). The per kWh avoided energy costs will be those reflected in or underlying the most recently filed IRP. If both the per kW avoided capacity costs and per kWh avoided energy costs approved by the Commission in Sub 136 and the IRP proceeding are within 2% of the costs filed by the Company in this proceeding, no change will be necessary. If either changes by more than 2%, both costs will be changed to the amounts approved by the Commission. For the PPI for Vintage Years 2015, 2016, and 2017, if either (a) the Company's per kWh avoided energy costs calculated for the purposes of the Company's annual IRP or resource plan update filings have increased or decreased by 20% or more, or (b) the Company's per kW avoided capacity costs reflected in the rates approved in the biennial avoided cost proceedings have increased or decreased by 15% or more, the avoided costs (both energy and capacity) will be updated for purposes of the DSM/EE rider proceeding.

The PPI for each vintage year shall ultimately be trued up based on net dollar savings as verified by the EM&V process and approved by the Commission. The process used to determine the trued-up PPI will be virtually the same as that used for the initial estimate, except using verified, rather than estimated, measurement units and kW/kWh savings, as well as actual program costs. The Stipulating Parties have agreed to strive to fully true-up all vintages within 24 months of the vintage program year.

Additional Incentive

The Additional Incentive section provides that if the Company achieves incremental energy savings of 1% of its prior year's system retail electricity sales in any year during the five-year period, 2014 through 2018, the Company will receive an additional bonus incentive of $400,000 for that year. Consistent with the methodology used to calculate the PPI, the Additional Incentive will be calculated based upon results verified through the approved EM&V process.

Financial Reporting Requirements

The Financial Reporting Requirements section provides that in its quarterly ES-1 Reports to the Commission, DEC shall calculate and present its primary North Carolina retail jurisdictional earnings by including all actual EE and DSM program revenues, including PPI and Net Lost Revenues incentives, and costs. Additionally, the Company shall prepare and present certain supplementary schedules and provide detailed workpapers.

Review of Mechanism

The Review of Mechanism section provides that the Mechanism will be reviewed by the Commission every four years unless otherwise ordered. During the time the review is taking place, the Mechanism shall remain in effect until further order of the Commission.

The Mechanism as described by Company witness Duff and Public Staff witness Maness is set forth in the Stipulation, and is recommended for Commission approval by the Company, the Public Staff, and the other Stipulating Parties.

As the Commission held in Docket Nos. E-2, Sub 931, E-7, Sub 831, and E-22, Sub 464, for DEP (then Progress Energy Carolinas, Inc.), DEC, and DNCP, respectively, the proper level of incentives is by nature a balancing act. Incentives should not be excessive, but must be sufficient to motivate a utility to deploy DSM/EE programs effectively.

Pursuant to the Stipulation, as a further incentive to pursue all cost-effective EE programs, the Company will have the ability to earn a bonus incentive if it achieves incremental energy savings of 1% of the prior year's retail electric sales in any year during the five-year period, 2014 through 2018. While the Stipulation has had no impact on the projected results of the projected EE achievement levels of the Company's proposed portfolio, the Company's ability to earn the bonus incentive would require the Company to significantly increase the magnitude of the EE savings achievement above the current projected levels. Public Staff witness Maness testified that should the Company achieve the required level of savings for the additional incentive, the impact of the $400,000 annual bonus itself on residential customers' monthly bills should be very small, perhaps even zero on a 1,000 kWh bill. The Commission finds that the bonus incentive meets the criteria of not being excessive, but being sufficient to motivate DEC to deploy DSM/EE programs effectively.

After careful consideration, the Commission is of the opinion that the overall package of incentives, including the recovery of Net Lost Revenues, proposed by the Stipulating Parties should be sufficient to properly motivate DEC. Based upon the evidence in this proceeding, the Commission thus concludes that the incentives proposed by the Stipulating Parties are reasonable and appropriate for use in this proceeding. In reaching this conclusion, the Commission is further guided by the fact that the Stipulating Parties will review the terms and conditions of the Mechanism at least every four years and submit any proposed changes to the Commission for approval. Accordingly, the Commission concludes that the PPI, Additional Incentive, and Net Lost Revenue incentive, as proposed by the Stipulating Parties, should be approved, subject to review by the Stipulating Parties in four years.

The Commission also finds, based on the evidence presented in this proceeding, that the terms of the Mechanism are reasonable and appropriate. As testified to by the Public Staff, one of the advantages of a shared savings mechanism like the one recommended as part of the Stipulation is that the incentive is 100% sensitive to changes in net DSM/EE dollar savings. Additionally, a shared savings mechanism rewards the utility for the pursuit and achievement of cost-effective EE and DSM. Therefore, the Commission concludes that the incentives and Mechanism proposed by the Stipulating Parties should be approved, subject to the restrictions set forth in the Mechanism and continuing review for reasonableness as necessary and appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 18

The evidence for this finding of fact is contained in the testimony and exhibits of DEC witness McManeus and Public Staff witness Hinton.

As detailed by Company witness McManeus in her direct testimony, the Company proposed in its Application that the avoided costs as filed in Sub 136 remain fixed unless total avoided capacity and energy costs as approved by the Commission change by 20% or more. In such case, either the Company or the Public Staff could request that impacts of the change in avoided cost be reviewed and may recommend appropriate changes, if any, to be applied prospectively to the Company's portfolio of programs for the purpose of determining program cost-effectiveness and hence the incentive achievement level for the new portfolio.

Public Staff witness Hinton testified regarding concerns he had about the Company’s avoided transmission and distribution (T&D) rates used in its cost-effectiveness tests. He recommended that the Company perform a detailed review of its avoided T&D costs to determine the specific types of capital expenditures for its T&D system that can be effectively avoided by the reduced peak load from a DSM/EE program. He also proposed that the Company’s avoided cost rates be trued up rather than fixed as proposed in the Company’s original filing.

Pursuant to the Stipulation, the Company will use its filed Sub 136 per kW avoided capacity costs and per kWh avoided energy costs reflected in or underlying its most recent IRP to calculate the PPI. The Stipulating Parties have agreed that if both the per kW avoided capacity costs and per kWh avoided energy costs approved by the Commission in Sub 136 and the IRP proceeding are within 2% of the costs filed by the Company, no change from the costs used will be necessary. If either changes by more than 2%, both costs will be changed to the approved amounts. For the PPI for Vintage Years 2015, 2016, and 2017, the presumptive per kW avoided capacity costs and per kWh avoided energy costs used to calculate avoided cost savings will be those used for Vintage Year 2014. However, if at the time of initial estimation of the PPI for each of those years, either (a) the Company's per kWh avoided energy costs calculated for the purposes of the Company's biennial IRP or IRP update have changed by 20% or more, or (b) the Company's per kW avoided capacity costs reflected in the rates approved in the biennial avoided cost proceedings have increased or decreased by 15% or more, both the avoided energy and capacity costs will be updated.

The Company has also reflected avoided T&D costs in the avoided cost savings used to compute the PPI. The Stipulating Parties agree that the Company's initially proposed avoided T&D cost rates are reasonable for Vintage Year 2014. The Company and the Public Staff have agreed to engage in a joint effort to review the proposed avoided T&D cost rates for Vintage Year 2015. However, the Company and the Public Staff have agreed that if the review of the avoided T&D rates results in a change of less than 2% from the rates used in this proceeding, no further adjustment is required.

The Commission finds that these provisions of the Stipulation are reasonable and appropriate and should be approved.

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

The evidence for these findings of fact is contained in the testimony and exhibits of DEC witness McManeus.

Under the terms of the Mechanism, the Vintage Year 2014 Rider EE charges (including gross receipts tax and regulatory fee) are 0.2779 cents per kWh for residential customers, 0.0963 cents per kWh for non-residential customers participating in Vintage Year 2014 EE programs, and 0.0797 cents per kWh for non-residential customers participating in Vintage Year 2014 DSM programs. No party has objected to the calculation of these billing factors. Therefore, the Commission concludes that the reasonable and prudent Vintage Year 2014 prospective billing factors are as proposed by the Company in witness McManeus' settlement exhibits, including her revised exhibits filed on August 27, 2013. These Vintage Year 2014 billing factors should replace the applicable estimated factors proposed by the Company as part of Rider 5 in Docket No. E-7, Sub 1031, the Company's pending annual DSM/EE cost and incentive recovery proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 22

The evidence for this finding of fact is contained in the Application, the testimony of all the witnesses, the Stipulation and the entire record of this proceeding.

As fully discussed in Finding of Fact and Conclusion No. 4, the provisions of the Stipulation are the product of the give-and-take of settlement negotiations between DEC, the Public Staff, and the other Stipulating Parties. As a result, the Stipulation reflects the fact that DEC agreed to certain provisions that advanced the interests of the other Stipulating Parties and that those parties agreed to other provisions that advanced DEC's interests. The end result is that the Stipulation strikes a fair balance between the interests of DEC and its customers. The Commission concludes that the Stipulation and Mechanism is just and reasonable to all parties in light of the evidence presented and serves the public interest. Therefore, the Commission concludes that the Stipulation and Mechanism should be approved in its entirety.

IT IS, THEREFORE, ORDERED as follows:

1. That the portfolio of DSM and EE programs filed by DEC is approved as filed, except: (a) the programs are approved without a specific term and (b) the Non-Residential $mart-Saver® Custom Program and Non-Residential Smart Saver® Custom Energy Assessments Program do not exclude bottoming-cycle CHP or the waste heat recovery components of topping-cycle CHP;

2. That the Company shall meet with NC WARN, the Public Staff, and other interested intervenors to discuss the proposals submitted by NC WARN regarding the alternatives to the Company's Multi-Family EE Program and Income-Qualified EE and Weatherization Program, with the intent of developing a Community Enhanced Program and revisions to DEC's Multi-Family Program to present to the Company's Carolinas Energy Efficiency Collaborative (Collaborative) for discussion and refinement, and possibly filing such proposals with the Commission;

3. That OBR and CHP shall be discussed as part of the Collaborative, with such discussion and consideration to commence no later than December 31, 2013. The Company shall report to the Commission the results of the OBR and CHP Collaborative consideration in connection with its next DSM/EE rider proceeding. To the extent the discussion and consideration of either OBR or CHP is ongoing, the Company shall provide a status update in connection with its next DSM/EE rider proceeding, with a report to follow in a subsequent DSM/EE rider proceeding;

4. That the following waivers of Commission Rules are granted: (a) waiver of Rule R8-69(d)(3) to (i) allow the Company more flexibility in implementing and managing the opt-out elections of individual commercial customers with annual energy usage of not less than 1,000,000 kWh and industrial customers from participating in either the Company's DSM programs or EE programs, or both in combination, as set forth in the Commission's Order Granting Waiver, in Part, and Denying Waiver, in Part (Sub 938 Waiver Order) issued on April 6, 2010, in Docket No. E-7, Sub 938, and (ii) allow the Company to implement its proposal for an additional election period in March; (b) waivers of Rules R8-69(a)(4) and R8-69(a)(5) as approved by the Commission in its June 3, 2010 Order on Motions for Reconsideration in Docket No. E-7, Sub 938 (Sub 938 Second Waiver Order), for the duration of the Mechanism, unless otherwise ordered by the Commission in the future; and (c) waiver of Rule R8-69(b)(6) to allow the compounding of interest pursuant to the methodology used for the calculation of the return allowed for over- and under-recovered amounts as provided for in Paragraph 47 of the Stipulation;

5. That the agreement approved by the Commission in its November 8, 2011 Order Approving DSM/EE Rider and Requiring Filing of Proposed Customer Notice in Docket No. E-7, Sub 979, regarding the application of Experience, Measurement, and Verification results (EM&V Agreement), shall continue to apply to the new portfolio of programs;

6. That the agreement approved by the Commission in its July 16, 2012 Order Adopting Program Flexibility Guidelines in Docket No. E-7, Sub 831, regarding the flexibility to make program changes (Flexibility Guidelines), shall continue to apply to the new portfolio of programs;

7. That the agreement approved by the Commission in its February 8, 2011 Order Adopting "Decision Tree" to Determine "Found Revenues" and Requiring Reporting in DSM/EE Cost Recovery Filings in Docket No. E-7, Sub 831, regarding the determination of found revenues (Decision Tree), shall continue to apply to the new portfolio and Mechanism;

8. That the Stipulation and Mechanism filed by the Stipulating Parties is hereby approved;

9. That DEC's proposed Vintage Year 2014 billing factors pursuant to the Stipulation are hereby approved. These billing factors shall supersede and replace the applicable estimated factors proposed by the Company as part of Rider 5 in Docket No. E-7, Sub 1031;

10. That the Company and Public Staff shall study the issue of the appropriate avoided transmission and distribution (T&D) costs to be used in the Company's calculations of cost-effectiveness and, if any adjustment is determined to be appropriate, the proposed adjustment will be filed in the Company's 2014 DSM/EE rider proceeding to be made on a prospective basis. The Company and the Public Staff shall jointly review the proposed avoided T&D cost rates for Vintage Year 2015 and propose adjustments, if appropriate;

11. That, unless requested to do so earlier by the Company, the Public Staff, or another interested party, the Commission shall initiate a formal review of the Commission-approved Mechanism not later than July 1, 2017; and

12. That DEC shall work with the Public Staff to prepare a proposed Notice to Customers of the rate changes approved herein and in the Commission's Order Approving DSM/EE Rider and Requiring Filing of Proposed Customer Notice issued in Docket No. E-7, Sub 1031. Within 30 days from the date of this Order, the Company shall file said notice and the proposed time for service of such notice for Commission approval.

ISSUED BY ORDER OF THE COMMISSION.
This the 29th day of October, 2013.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

Commissioner Don M. Bailey did not participate in this decision.

Bh102913.01

DOCKET NO. E-22, SUB 494

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Virginia Electric and Power Company d/b/a Dominion North Carolina Power for Approval of Demand Side Management and Energy Efficiency Cost Recovery Rider Pursuant to G.S. 62-133.9 and Commission Rule R8-69	))))))	ORDER APPROVING DSM/EE AND DSM/EE EMF RIDERS AND REQUIRING CUSTOMER NOTICE

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

HEARD: Wednesday, November 13, 2013, Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

APPEARANCES:

FOR DOMINION NORTH CAROLINA POWER:

Vishwa B. Link, McGuireWoods, LLP, One James Center, 901 East Cary Street, Richmond, Virginia 23219

E. Brett Breitschwerdt, McGuireWoods, LLP, 434 Fayetteville Street, Suite 2600, Raleigh, North Carolina 27601

FOR THE USING AND CONSUMING PUBLIC:

David T. Drooz, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: General Statute 62-133.9(d) authorizes the Commission to approve an annual rider to the rates of electric utilities to recover all reasonable and prudent costs incurred for the adoption and implementation of new demand-side management and energy efficiency (DSM/EE) programs. In accordance with Commission Rule R8-69(b), such rider consists of the utility's reasonable and appropriate estimate of expenses expected to be incurred during the rate period and an experience modification factor (EMF) rider to collect or refund the difference between the utility's actual reasonable and prudent costs incurred during the test period and actual revenues realized during the test period under the DSM/EE rider then in effect. The Commission is also authorized to award incentives to electric utilities for adopting and implementing new DSM/EE programs, including appropriate rewards based on the sharing of savings achieved by the programs. These utility incentives are included in the utility's reasonable and appropriate estimate of expenses expected to be incurred during the rate period and DSM/EE EMF riders described above.

Further, Commission Rule R8-69(b) provides that the Commission will each year conduct a proceeding for each electric utility to establish an annual DSM/EE rider to recover DSM/EE related costs and utility incentives. Commission Rule R8-69(e) provides that the annual DSM/EE cost recovery rider hearing for each public utility will be scheduled as soon as practicable after the annual fuel and fuel-related charge adjustment proceeding held by the Commission for the electric public utility under Commission Rule R8-55.

On August 20, 2013, Virginia Electric and Power Company d/b/a Dominion North Carolina Power (DNCP or the Company) filed in this docket its Application for Approval of Cost Recovery for Demand-Side Management and Energy Efficiency Measures (Application), together with the prefiled direct testimony and exhibits of its witnesses Brandon E. Stites, Ripley C. Newcomb, Michael J. Jesensky, David L. Turner, C. Alan Givens, J. Clayton Crouch, and Robert C. Rice for the approval of a DSM/EE rider to recover the Company's reasonable and prudent forecasted DSM/EE costs, capital costs, indirect common costs, taxes, net lost revenues (NLR), and a Program Performance Incentive (PPI) for implementation of its DSM/EE programs.

DNCP's Application requested an annual projected rate period revenue requirement of $3,310,828 to be recovered through its updated DSM/EE rider, Rider C, effective on and after January 1, 2014. DNCP also requested approval of a decrement DSM/EE EMF rider, Rider CE, in the amount of ($899,739), to true up its actual costs and revenues received under Rider C rates in effect during the period July 1, 2012 through June 30, 2013. This request, including gross receipts taxes, would result in the following kilowatt-hour (kWh) charges: 0.093 cents per kWh for residential customers; 0.084 cents per kWh for small general service and public authority customers; 0.106 cents per kWh for large general service customers; and 0.091 cents per kWh for rate schedule 6VP customers. The net effect of these requests would increase the monthly bill of a typical residential customer using 1000 kWh by approximately $0.01, or approximately 0.01%.

Contemporaneous with DNCP's filing of its Application in this docket, the Company also filed eight new DSM and EE programs for Commission approval under Commission Rule R8-68. These programs include the North Carolina-only Commercial Lighting Program; North Carolina-only Commercial HVAC Upgrade Program; Non-Residential Energy Audit Program; Non-Residential Duct Testing and Sealing Program; Residential Home Energy Check Up Program; Residential Duct Testing & Sealing Program; Residential Heat Pump Tune Up Program; and Residential Heat Pump Upgrade Program.[1] The Company requested that each of these new Programs be approved to begin accepting participants in North Carolina on January 1, 2014, and the costs and incentives associated with implementing these new Programs be approved for recovery in this proceeding.

Proceedings in Prior Dockets

On October 14, 2011, in Docket No. E-22, Sub 464 the Commission issued its Order Approving Agreement and Stipulation of Settlement, Approving DSM/EE Rider, and Requiring

[1] These eight new DSM/EE programs were filed for approval in Docket No. E-22, Subs 467, 469, and 495-500.

Compliance Filing (2010 Cost Recovery Order). In the 2010 Cost Recovery Order, the Commission approved the Agreement and Stipulation of Settlement between the Public Staff and the Company (Stipulation), filed on March 2, 2011, as well as the Cost Recovery and Incentive Mechanism (Mechanism), attached as Stipulation Exhibit 1 to the Stipulation (collectively, Stipulation and Mechanism).

On December 13, 2011, in Docket No. E-22, Sub 473 the Commission issued its Order Approving DSM/EE Rider and Requiring Customer Notice in DNCP's 2011 DSM/EE cost recovery proceeding (2011 Cost Recovery Order). The 2011 Cost Recovery Order also approved a first Addendum to the Stipulation and Mechanism (Addendum I) related to jurisdictional allocation of DSM/EE costs. The Addendum I is now incorporated as part of the Stipulation and Mechanism.

On April 29, 2013, in Docket No. E-22, Sub 486 the Commission issued its Order Granting Conditional Approval of Cost Assignment Proposal that approved a cost assignment methodology for purposes of allocating DNCP's costs of offering its Commercial Lighting Program and HVAC Upgrade Program only in North Carolina. The cost assignment methodology had been agreed upon by DNCP and the Public Staff. In the present docket, DNCP filed a copy of the approved cost assignment methodology as Attachment 1 to its Application, and requested that the Commission incorporate it into the Stipulation and Mechanism as Addendum II (Addendum II).

Proceedings in the Present Docket

On September 12, 2013, the Commission issued an Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice regarding DNCP's Application. Pursuant to this Order, the Commission established deadlines for the filing of petitions to intervene, intervenor testimony and exhibits, and Company rebuttal testimony and exhibits, and scheduled a hearing to be held in this proceeding on November 13, 2013.

On September 26, 2013, DNCP filed the Exhibit CAG-1, Schedule 3, workpapers of Company witness C. Alan Givens.

On September 27, 2013, the North Carolina Sustainable Energy Association (NCSEA) filed a motion to intervene in the proceeding. On October 2, 2013, the Commission issued an order allowing NCESA's motion. Intervention and participation in this docket by the Public Staff is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

On October 18, 2013, DNCP filed its Affidavit of Publication indicating that it had provided notice in newspapers of general circulation as required by the Commission's September 12, 2013 Order.

On October 30, 2013, the Public Staff filed the Affidavits of Jack L. Floyd, Electric Engineer, Electric Division, and Michael C. Maness, Assistant Director, Accounting Division.

On November 1, 2013, DNCP filed a motion seeking authority to allow Vishwa B. Link, an attorney licensed to practice in the Commonwealth of Virginia, to appear pro hac vice on behalf of DNCP in this docket. The Commission granted the motion for limited appearance by Order issued on November 8, 2013.

On November 6, 2013, the Company prefiled rebuttal testimony and exhibits of its witnesses Brandon E. Stites, Ripley C. Newcomb, Michael J. Jesensky, C. Alan Givens, J. Clayton Crouch, and Robert C. Rice in support of its Application and in response to the affidavits filed by the Public Staff. The Company's rebuttal testimony updated the DSM/EE EMF Rider CE revenue requirement refund amount to ($911,589). No other changes to the revenue requirement were proposed by the Company's rebuttal testimony.

On November 8, 2013, the Public Staff and DNCP filed a Joint Motion to Excuse Witnesses, stating that they had reached agreement on all issues in this docket and had agreed to waive cross-examination of each other's witnesses. Further, the Joint Motion requested that the Commission excuse the Public Staff and DNCP witnesses from attending the evidentiary hearing on November 13, 2013, and admit the testimony and exhibits of those witnesses into evidence at the hearing. On November 12, 2013, the Commission issued an Order granting the Joint Motion.

On November 13, 2013, the Commission held the evidentiary hearing as scheduled. No public witnesses appeared or testified at the hearing.

DNCP and the Public Staff jointly filed a Proposed Order on December 4, 2013.

Based upon DNCP's application, the testimony and exhibits received into evidence at the hearing, and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

1. Virginia Electric and Power Company is a public utility operating in the State of North Carolina as DNCP, is engaged in the business of generating, transmitting, distributing, and selling electric power and energy to the public for compensation in North Carolina, and is subject to the jurisdiction of the North Carolina Utilities Commission as a public utility.

2. DNCP is lawfully before this Commission based upon its application filed pursuant to G.S. 62-133.9 and Commission Rule R8-69.

3. Pursuant to Commission Rule R8-69, the rate period for purposes of this proceeding is the 12-month period January 1, 2014, through December 31, 2014.

4. Pursuant to Commission Rule R8-69, the test period for purposes of this proceeding is the 12-month period July 1, 2012, through June 30, 2013.

5. DNCP has requested rate period recovery of costs and incentives related to the following approved DSM/EE programs: (a) Low Income Program; and (b) Residential Air Conditioner Cycling Program. DNCP has also requested the recovery of costs and incentives related to the following proposed DSM/EE programs: (a) North Carolina-Only Commercial HVAC Upgrade Program; (b) North Carolina-Only Commercial Lighting Program; (c) Non-Residential Energy Audit Program; (d) Non-Residential Duct Testing and Sealing Program; (e) Residential

Home Energy Check Up Program; (f) Residential Duct Testing & Sealing Program; (g) Residential Heat Pump Tune Up Program; and (h) Residential Heat Pump Upgrade Program.

6. Consistent with the Orders Approving Programs issued by the Commission on December 16 and 17, 2013, in Docket No. E-22, Subs 467, 469, and 495-500, it is reasonable and appropriate for the Company to recover the costs associated with offering each of the ongoing and newly approved DSM/EE Programs during the rate period.

7. Addendum II is reasonable and appropriate for inclusion as part of the Stipulation and Mechanism.

8. Recovery via Rider C of DNCP's forecasted DSM/EE program costs, common costs, NLR, and a PPI, as well as a true up via Rider CE of DNCP's test period DSM/EE program costs, common costs, NLR, and a PPI, are subject to the terms of the Stipulation and Mechanism agreed to between the Company and the Public Staff and approved by the Commission in the 2010 Cost Recovery Order, as modified by the 2011 Cost Recovery Order and as further modified by Addendum II.

9. Recovery of the Company's incremental common costs not directly related to specific DSM or EE programs, as well as NLR and a utility incentive in the form of a PPI, are reasonable and consistent with the Stipulation and Mechanism.

10. For purposes of determining Rider C, DNCP's reasonable and appropriate estimate of its North Carolina retail DSM/EE total revenue requirement, consisting of DSM/EE program costs, common costs, NLR, and a PPI, is $3,310,828. This is the appropriate amount to use to develop the forward-looking DSM/EE revenue requirement for recovery through Rider C.

11. Rider C is reasonable and appropriate, and consists of the following customer class billing factors (including Gross Receipts Tax (GRT)): Residential – 0.141 ¢/kWh; Small General Service and Public Authority – 0.098 ¢/kWh; Large General Service – 0.124 ¢/kWh; 6VP – 0.106 ¢/kWh; and no charge for NS, Outdoor Lighting, and Traffic Lighting. It is reasonable and appropriate for Rider C to become effective for usage on and after January 1, 2014.

12. For purposes of determining its DSM/EE EMF, Rider CE, DNCP's reasonable and prudent North Carolina retail total revenue requirement for the DSM/EE EMF Test Period, consisting of amortized DSM/EE program costs, common costs, and utility incentives, is ($911,589). This DSM/EE EMF refund includes interest of 10% on the over-recovery amount, as contemplated by Commission Rule R8-69(b)(3) and the Mechanism.

13. Rider CE is reasonable and appropriate, and consists of the following decrements to customer class billing factors (including GRT): Residential – (0.049) ¢/kWh; Small General Service and Public Authority – (0.014) ¢/kWh; Large General Service – (0.018) ¢/kWh; 6VP – (0.015) ¢/kWh; and no charge for NS, Outdoor Lighting, and Traffic Lighting. It is reasonable and appropriate for Rider CE to become effective for usage on and after January 1, 2014.

14. DNCP requested the recovery of NLR and a PPI in the amount of $140,556 for the test period and $836,355 for the rate period. DNCP's calculation and proposed recovery of NLR and a PPI is consistent with the Stipulation and Mechanism, and is appropriate for recovery in this proceeding.

15. In the present proceeding, DNCP provided the Commission with an explanation of its consumer education and awareness activities and the volume of activity associated with each initiative during the test period, as initially directed by the Commission's 2011 Cost Recovery Order in Docket No. E-22, Sub 473. It is appropriate for DNCP to continue to provide such information to the Commission in future rider proceedings.

16. The evaluation, measurement, and verification (EM&V) analyses and reports prepared by DNCP are reasonable for purposes of this proceeding. The EM&V data provided by DNCP and reviewed by the Public Staff for vintage years 2011 and 2012 is sufficient to consider those vintage years complete for all programs operating in those years. It is appropriate for DNCP to incorporate the EM&V recommendations of Public Staff witness Floyd in future EM&V.

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

These findings of fact are essentially informational, procedural, and jurisdictional in nature and are uncontroverted. The rate period and test period used by DNCP are consistent with Commission Rule R8-69.

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

The evidence for these findings of fact is contained in DNCP's Application, the testimony of DNCP witnesses Stites and Crouch, the affidavits of Public Staff witnesses Floyd and Maness filed in this proceeding, and the Comments of the Public Staff and the Commission's Orders Approving Programs in Docket No. E-22, Subs 467, 469, and 495-500.

The Company's Application requested approval of rate period cost recovery for (i) its ongoing Phase I Residential Low Income and Air Conditioner Cycling Programs; (ii) six proposed Phase II DSM/EE programs that have been previously approved by the Virginia State Corporation Commission and are now deployed in the Company's Virginia jurisdiction; and (iii) two proposed North Carolina-only programs, the Commercial HVAC Upgrade and Commercial Lighting Programs. Company witness Stites explained that DNCP began offering these Phase II programs in its Virginia jurisdiction in the summer of 2012, and, subject to Commission approval, proposes to begin accepting customers in North Carolina beginning on January 1, 2014.

With regard to the two North Carolina-only programs, witness Stites explained that the Commission previously allowed DNCP to suspend these two system-wide programs in order to evaluate whether they could cost-effectively be offered only in North Carolina, and to work with the Public Staff on a more appropriate cost recovery methodology that would align recovery of program costs with the benefits of offering the programs only in North Carolina. On February 12, 2013, in Docket No. E-22, Sub 486, the Company filed "100% cost assignment language," in agreement with the Public Staff, for purposes of recovering the costs of offering these two programs on a North Carolina-only basis. On April 29, 2013, the Commission's Order Granting Conditional Approval of the cost assignment language in Docket E-22, Sub 486, conditionally approved DNCP's and the Public Staff's 100% cost assignment proposal, subject to (1) DNCP submitting updated program applications, including cost-effectiveness results, in accordance with Commission Rule R8-68; (2) Commission approval of the refiled North Carolina-only programs; (3) DNCP and the Public Staff submitting a signed amendment to the Addendum memorializing the agreed-upon 100% cost assignment language; and (4) DNCP sponsoring a witness in its annual DSM/EE cost recovery proceedings to address any Commission questions regarding cost recovery for these North Carolina-only programs. The Company filed the two North Carolina-only programs contemporaneous with its Application in this docket. The Company filed Addendum II as Attachment 1 to the Company's Application in this docket, and witness Crouch fully assigned the costs of these two programs to the North Carolina retail jurisdiction in accordance with the 100% cost assignment language presented in proposed Addendum II to the Stipulation and Mechanism.

Public Staff witness Floyd testified that the Public Staff supported DNCP's request to recover its costs associated with the previously approved Phase I DSM/EE programs and conditionally supported inclusion of the pending Phase II and North Carolina-only programs contingent on the Commission's approval of each of the programs as a new DSM/EE program under Rule R8-68. On November 25, 2013, the Public Staff filed comments in each of the program approval dockets in support of Commission approval of the two North Carolina-only programs and six Phase II programs, subject to certain enumerated conditions, to which the Company had no objection.

On December 18, 2013, the Commission issued Orders Approving Programs for the two North Carolina-only programs and six Phase II programs in Docket No. E-22, Subs 467, 469, and 495-500.

Consistent with the Commission's Orders Approving Programs allowing the Company to accept North Carolina retail customers in each of the Company's DSM/EE Programs on and after January 1, 2014, the Commission finds and concludes that DNCP should be allowed to recover its projected rate period costs associated with offering each of its ongoing and newly approved programs as requested in its Application. The Commission also finds that Addendum II memorializing the agreed-upon 100% cost assignment language between DNCP and the Public Staff is reasonable and should be approved and incorporated as Addendum II to the Stipulation and Mechanism.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 8-14

The evidence for these findings of fact is contained in the testimony and exhibits of DNCP witnesses Stites, Newcomb, Turner, Givens, Crouch, and Rice and the affidavit of Public Staff witness Maness.

In his direct testimony, Company witness Turner provided evidence regarding the estimated system-level or North Carolina-only program costs of the Company's portfolio of

DSM/EE programs, and common costs associated with implementing the system-level or North Carolina-only Programs. According to witness Turner, "program costs" are costs directly attributable to individual programs, while "common costs" are costs associated with the overall effort of designing, implementing, and operating the DSM/EE programs, but not directly attributable to any individual program. Witness Turner also provided actual DSM/EE program and common costs for currently operational programs for the July 1, 2012 through June 30, 2013 test period.

Witness Turner also calculated DNCP's projected rate period PPI amount for the previously approved Phase I Residential Lighting, Commercial Lighting, and Commercial HVAC Upgrade Programs, the six Phase II Programs and the North Carolina-only Commercial HVAC Upgrade and Commercial Lighting Programs. Witness Turner also calculated a PPI true up for the previously-approved Phase I Residential Lighting, Commercial Lighting, and Commercial HVAC Upgrade Programs for vintage year 2011, and a PPI true up for the Phase I Commercial Lighting Program for vintage year 2012.

Company witness Givens testified that DNCP's projected revenue requirement includes the following cost components: (1) operating expenses projected to be incurred during the rate period, (2) capital costs (including related depreciation expense) projected to be incurred during the rate period, (3) a PPI projected for the rate period, and (4) NLR projected to be incurred during the rate period. Witness Givens calculated DNCP's requested North Carolina retail rate period (January 2014 through December 2014) revenue requirement as follows:

1. Operating Expense	$2,365,596
2. Capital Cost	$ 108,878
3. NLR	$ 716,451
4. PPI	$ 119,904
5. Total	$3,310,828

Company witness Givens also calculated DNCP's DSM/EE EMF revenue requirement, which includes actual costs (both capital and operation and maintenance (O&M) components), a PPI, and actual NLR for the DSM/EE EMF test period. The DSM/EE EMF revenue requirement was initially calculated to be a refund of ($899,739).

Public Staff witness Maness recommended certain limited adjustments related to the Company's calculation of carrying charges on the test period over-recovery amount used to calculate the Rider CE DSM/EE EMF Rider revenue requirement. Specifically, witness Maness noted that the Company calculated carrying charges (a return) and interest on the over-recovery of its test period DSM/EE revenue requirement using methodologies that produce (1) carrying charges due to ratepayers higher than prescribed by the Mechanism and Commission Rule R8-69(b)(6) and (c)(3), and (2) an interest amount pursuant to the Mechanism and Commission Rule R8-69(b)(3) lower than what would be produced by the 10% simple interest rate applied to the average over-recovered balance method recommended by witness Maness and traditionally adopted by the Commission. To address these concerns, witness Maness made two adjustments to the Company's Rider CE DSM/EE EMF revenue requirement calculation. First, he applied the maximum statutory rate of 10% per annum, set forth in G.S. 62-130(e), as the interest rate to be used on DNCP's pre-tax average outstanding balance, as historically approved by the Commission for refunds of this type. Second, witness Maness proposed to include the carrying charges accrued pursuant to Paragraph 23 of the Mechanism in the amount to which the 10% interest is applied.

DNCP witness Givens testified in his rebuttal testimony that for purposes of this case, the Company accepts the adjustments proposed by witness Maness to the DSM/EE EMF Rider CE revenue requirement. Witness Givens also testified as to three minor corrections to the Rider CE DSM/EE EMF revenue requirement calculation that were identified during the discovery process and discussed with the Public Staff as part of the Company's effort to come to an agreement as to the proper revenue requirement in this proceeding. These three corrections included (1) incorporating updated test period kWh energy reductions for the Low Income Program provided by Company witness Jesensky; (2) updating the State Apportionment Transactional Rate; and (3) incorporating the updated North Carolina retail jurisdictional allocation factor used to allocate common costs to the North Carolina retail jurisdiction provided by Company witness Crouch. As a result of witness Maness' recommendations and the three updates to the Rider CE revenue requirement supported by witness Givens, the DSM/EE EMF revenue requirement was updated by witness Givens to a refund of ($911,589).

For the continuing Phase I and proposed Phase II system programs, Company witness Crouch allocated common costs to the DSM/EE programs, allocated program costs to the North Carolina retail jurisdiction, and then assigned (residential programs) and allocated (commercial programs) costs to the customer classes in accordance with Sections 3.A, 3.B, and 3.C of the Stipulation and Mechanism, respectively. Witness Crouch also directly assigned 100% of the projected rate period costs of the proposed North Carolina-only Commercial HVAC Upgrade and Commercial Lighting Programs to the North Carolina retail jurisdiction, in accordance with Addendum II to the Stipulation and Mechanism. Witness Crouch's rebuttal testimony updated the allocations and assignments for the Rider CE DSM/EE EMF revenue requirement provided by Company witness Givens.

Per these allocations and assignments, the North Carolina retail jurisdictional rate period revenue requirement was allocated to the classes as follows:

Rate Class	Rider C Amount	Rider CE Amount
Residential	$2,150,077	$(734,803)
SGS Co & Muni	$752,426	$(106,915)
LGS	$270,572	$(38,447)
6VP	$137,753	$(19,574)
NS	$0	$0
ST & Outdoor Lighting	$0	$0
Traffic Lighting	$0	$0

Company witness Rice provided the North Carolina forecasted net kilowatt-hour (kWh) sales for the rate period, and calculated the Rider C and Rider CE rates designed to recover the Rider C and Rider CE revenue requirements allocated to the classes. Witness Rice proposed in testimony that the following customer class Rider C billing factors (including GRT) be put into effect on January 1, 2014: Residential – 0.141 ¢/kWh; Small General Service and Public Authority – 0.098 ¢/kWh; Large General Service - 0.124 ¢/kWh; 6VP - 0.106 ¢/kWh; and no charge for NS, Outdoor Lighting, and Traffic Lighting. Witness Rice also testified and set forth a rebuttal schedule proposing that the following customer class decrement Rider CE billing factors (including GRT) be put into effect on January 1, 2014: Residential – (0.049) ¢/kWh; Small General Service and Public Authority – (0.014) ¢/kWh; Large General Service – (0.018) ¢/kWh; 6VP – (0.015) ¢/kWh; and no charge for NS, Outdoor Lighting, and Traffic Lighting.

Other than the adjustments to carrying charges noted above, Public Staff witness Maness testified that the Public Staff's investigation of DNCP's filing indicates that the Company generally has calculated the proposed riders in accordance with the methods set forth in the approved Stipulation and Mechanism for recovery of costs, NLR, and the PPI. Public Staff witness Maness also testified that his investigation into DNCP's Application showed that the Company had calculated its PPI true ups for vintage years 2011 and 2012 in accordance with the Public Staff's recommendations and the Stipulation and Mechanism.

Based upon the testimony of witnesses Stites, Newcomb, Turner, Givens, Crouch, and Rice, the affidavit of witness Maness, and the entire record of this proceeding, the Commission finds and concludes that the DSM/EE EMF revenue requirement and proposed Rider CE billing factors to be charged during the rate period are appropriate. The Commission further finds and concludes that the projected DSM/EE rate period revenue requirement and Rider C billing factors to be charged during the rate period are appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The evidence for this finding of fact is contained in the testimony of DNCP witness Turner and in various Commission orders.

In response to Ordering Paragraph 4 of the Commission's 2011 Cost Recovery Order, DNCP witness Turner provided information on DNCP's consumer education and awareness initiatives and event sponsorships during the test period. Witness Turner explained that DNCP's Energy Conservation (EC) department actively ties its communication and outreach activities directly to a specific DSM/EE program, so general education and awareness actual costs are fairly limited. During the test period, the EC department exhibited or spoke at approximately 14 events in North Carolina and Virginia. This included presentations focused on the EC department's specific programs and activities, and energy conservation in general. The combined efforts reached approximately 55,500 people. DNCP's main event sponsorships during this time period were for the following events: North Carolina Sustainable Energy Conference for 2013; the Virginia Commonwealth University Energy and Sustainability Conference and the Virginia Governor's Conference on Energy for 2012. The EC department also exhibited at other community events such as Fall for Fairfax and Earth Day. In addition to this community presence, the EC department supplied materials for outreach purposes and in response to customer requests, including 250 Department of Energy general tip books and over 500 activity/coloring books on energy conservation.

Witness Turner also described the EC department's use of the Company's website to provide general education to its customers through tips, videos, and online home audit tools, among other channels. The Company's program home pages received over 79,000 visits in the past year. In addition, the EC department took advantage of DNCP's growing social media presence on both Facebook and Twitter (with over 31,000 fans and 22,000 followers, respectively). Whenever possible, the EC department attempts to utilize low cost channels to communicate general education to the Company's customers.

The Public Staff did not oppose DNCP's consumer education and awareness activities or costs.

The Commission finds and concludes that DNCP's consumer education and awareness activities and costs are reasonable for purposes of this proceeding. The Commission also finds that the Company should continue to include a list of consumer education and awareness activities and the volume of activity associated with each during the test period in its annual DSM/EE cost recovery filing.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

The evidence for this finding of fact is contained in the testimony of DNCP witness Jesensky, the affidavit of Public Staff witness Floyd, and various Commission orders.

DNCP witness Jesensky testified that the objectives of the Company's EM&V are to provide an assessment of each program's progress toward its goals, including tracking actual cumulative indicators over time versus planning assumptions, such as the number of participants, estimated energy (kWh) and demand (kW) savings, and program costs. EM&V tracking also provides, per participant, the average peak kW reduction, average kWh savings, if appropriate, and average participant incentive for each program. Witness Jesensky testified that DNCP filed the latest EM&V report by its consultant, DNV KEMA Energy and Sustainability (KEMA), with the Commission on April 1, 2013, reflecting North Carolina program activity through the end of 2012, including: (1) the number of participating customers, (2) estimated gross and net kW and kWh impacts for each of the programs, (3) associated program costs, and (4) any recommendations or observations following the analysis of the EM&V data. The Company will continue to file its annual EM&V report on April 1 each year. Witness Jesensky also noted that the Company had implemented the specific EM&V recommendations recommended by witness Floyd in DNCP's 2012 DSM/EE rider proceeding and provided the Public Staff with Residential Air Conditioner Cycling Program operational data as requested by the Public Staff in lieu of a snapback[1] analysis.

Public Staff witness Floyd testified that his review of DNCP's EM&V Report suggests that the Public Staff's past recommendations have for the most part been incorporated in the EM&V data used in this proceeding. Witness Floyd also testified that for purposes of this and

[1] "Snapback" refers to an increased use of electricity in the period following activation of DSM. For example, if DNCP interrupts air conditioner use of participating customers during an hour of peak demand, the air conditioners of those customers may subsequently run longer or harder to get the house back to the customers' thermostat settings.

previous DSM/EE cost recovery proceedings for DNCP, the EM&V Report data used to true up program savings and participation for vintage year 2012 and earlier vintages are sufficient to consider those vintage years to be complete for all programs operating in those years.

Witness Floyd also provided more detailed discussion of snapback and waste heat factors, as well as hours-of-use for lighting measures. Witness Floyd explained that his preliminary review suggests that limited savings could be achieved from further snapback analysis, such that conducting further evaluation to determine the exact amount of snapback would cost far more than any benefit in reduced PPI. Therefore, the Public Staff does not recommend further snapback analysis. Witness Floyd also recommended that DNCP begin applying waste heat factors for new lighting measures proposed through Residential or Commercial Lighting programs on or after January 1, 2014. Lastly, witness Floyd recommended that the "hours-of-use" estimates used to calculate lighting measure savings should be based on North Carolina-specific data when feasible and that DNCP should discuss and seek to reach agreement with the Public Staff on hours-of-use for EE lighting measures before filing DNCP's next EM&V report.

In his rebuttal testimony, DNCP witness Jesensky agreed with the Public Staff's waste heat factor recommendation and explained that, consistent with witness Floyd's recommendation, the Company would update its hours-of-use variable beginning January 1, 2014, to be consistent with the North Carolina hours-of-use variable reported by Duke Energy Progress, Inc., in Docket No. E-2, Sub 950.

The Commission finds that the EM&V analyses and reports prepared by DNCP are reasonable for purposes of this proceeding. The Commission also finds that DNCP has appropriately incorporated the Public Staff's prior EM&V recommendations into the current EM&V Report, and that DNCP should take the actions outlined in the rebuttal testimony of Company witness Jesensky in regard to its future EM&V. The Company should continue to file its updated EM&V Report on April 1 of each year and the Public Staff should continue to review future EM&V reports to ensure the reasonableness of the assumptions and EM&V data provided to the Commission. The Commission also finds and concludes that the EM&V Report data used to true up program savings and participation for vintage year 2012 and earlier vintages are sufficient to consider those vintage years to be complete for all programs operating in those years.

IT IS, THEREFORE, ORDERED as follows:

1. That Addendum II to the Stipulation and Mechanism entered into by DNCP and the Public Staff and filed by DNCP as Attachment 1 to its Application, attached hereto as Appendix A, is hereby approved.

2. That the appropriate annual DSM/EE rider, Rider C, to become effective on and after January 1, 2014, consists of the following customer class billing factors (including GRT): Residential – 0.141 ¢/kWh; Small General Service and Public Authority – 0.098¢/kWh; Large General Service – 0.124 ¢/kWh; 6VP – 0.106 ¢/kWh; and no charge for NS, Outdoor Lighting and Traffic Lighting.

3. That the appropriate annual DSM/EE EMF rider, Rider CE, to become effective on and after January 1, 2014, consists of the following decrement customer class billing factors (including GRT): Residential – (0.049) ¢/kWh; Small General Service and Public Authority – (0.014) ¢/kWh; Large General Service – (0.018) ¢/kWh; 6VP – (0.015) ¢/kWh; and no charge for NS, Outdoor Lighting and Traffic Lighting.

4. That the Notice to Customers attached hereto as Appendix B is appropriate and is hereby approved. The Company shall use such Notice to Customers to provide notice of the rate changes ordered by the Commission in this proceeding and in Docket No. E-22, Subs 502[1] and 503.[2]

5. That DNCP shall file appropriate rate schedules and riders with the Commission to implement the provisions of this Order as soon as practicable.

6. That DNCP shall continue to provide a listing of the Company's event sponsorship and consumer education and awareness initiatives during the test period in future DSM/EE rider proceedings.

ISSUED BY ORDER OF THE COMMISSION.
This the 18th day of December, 2013.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

APPENDIX A
Page 1 of 3

ADDENDUM II TO AGREEMENT AND STIPULATION OF SETTLEMENT

Virginia Electric and Power Company, d/b/a Dominion North Carolina Power ("DNCP" or the "Company") and the Public Staff-North Carolina Utilities Commission ("Public Staff"), collectively referred to as the Stipulating Parties, through counsel and pursuant to N.C. Gen. Stat. § 62-69, respectfully submit the following Addendum II to the Agreement and Stipulation of Settlement (Stipulation) approved by the North Carolina Utilities Commission ("Commission") in its October 14, 2011, Order issued in Docket No. E-22, Sub 464. This Addendum II sets forth the previously-filed "100% Cost Assignment Language," as conditionally approved by the Commission in its April 29, 2013, Order issued in Docket No. E-22, Sub 486, and is being resubmitted as a signed Addendum to the Stipulation in accordance with the Commission's direction in that Order. The Stipulating Parties hereby agree and stipulate as follows:

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[1] Application by DNCP for a fuel charge adjustment pursuant to G.S. 62-133.2 and Commission Rule R8-55.

[2] Application by DNCP for a Renewable Energy and Energy Efficiency Portfolio Standard adjustment pursuant to G.S. 62-133.7 and Commission Rule R8-67.

100% COST ASSIGNMENT LANGUAGE - COMMERCIAL LIGHTING AND COMMERCIAL HVAC UPGRADE PROGRAMS

With regard to the Commercial Lighting and Commercial HVAC Upgrade Programs (Programs), the following has been demonstrated:

1. Despite all reasonable efforts by Virginia Electric and Power Company d/b/a Dominion Virginia Power in the Commonwealth of Virginia (DVP) to have the Programs, or reasonably similar or comparable DSM/EE programs, continued to be approved for offering to Virginia retail jurisdictional customers on a going-forward basis, the Virginia State Corporation Commission (VSCC) discontinued approval of spending for the Programs as of April 30, 2012; consequently, DVP ceased offering the Programs to new participants in Virginia as of mid-May 2012.

2. On August 14, 2012, the North Carolina Utilities Commission (Commission) issued an order approving the motion of Virginia Electric and Power Company d/b/a Dominion North Carolina Power in the State of North Carolina (DNCP) to suspend the Programs in North Carolina pending evaluation of the cost-effectiveness of operating the Programs solely in North Carolina. Subsequently, in its December 14, 2012 Order in DNCP's DSM/EE cost and incentive recovery proceeding, the Commission ordered DNCP to collaborate with the Public Staff to perform this evaluation, as well as to evaluate the proper jurisdictional allocation of the costs of the Programs, and to file a proposal regarding the future of the Programs within 60 days of the date of the order.

If the Programs are approved by the Commission to be offered on a going forward basis only to North Carolina retail jurisdictional customers, the retail system-wide allocation methodology agreed to by the Public Staff and DNCP in the Addendum to Agreement and Stipulation of Settlement (Addendum), filed with the Commission in Docket No. E-22, Subs 464 and 473, on November 4, 2011, and approved by the Commission in Sub 473 on December 13, 2011, would result in certain costs of the Program being allocated to the Virginia retail jurisdiction and certain Virginia

non-jurisdictional customers for North Carolina regulatory purposes, while not being recoverable in Virginia for Virginia regulatory purposes, at least for the time being.[1]

Over the past several months, pursuant to discussions held between DNCP and the Public Staff (the Stipulating Parties) in accordance with the Addendum, the Stipulating Parties have worked together to determine the appropriate jurisdictional allocation of the costs of the Programs, should they be offered only to North Carolina retail customers? As a result of these discussions, the

[1] This impact on DNCP's ability to fully recover its total DSM/EE costs differs from that caused simply by different jurisdictions utilizing differing allocation methodologies.

Stipulating Parties have agreed in principle that for as long as the Programs are offered to only North Carolina retail customers, 100% of the incremental costs of the Programs may be allocated to North Carolina retail jurisdictional operations for purposes of the annual DSM/EE cost recovery proceedings, provided that a reasonable estimate of 100% of the applicable incremental savings from the Programs shall also be allocated to North Carolina retail operations.

To estimate incremental savings, DNCP and the Public Staff have worked together to develop an approach which involves comparing the avoided cost of the DSM/EE Programs to the amount of savings that will naturally flow to the North Carolina retail ratepayers through the operations of the Company's jurisdictional cost of service study, and then "truing up" any difference between the two in the annual DSM/EE cost recovery proceedings. Such a "truing up" could result in a positive or a negative adjustment. As part of this approach, the impact on the jurisdictional cost of service study of the Commercial Distributed Generation Program, which is currently offered only by DVP in Virginia, will also be considered.

Using current estimates, the difference between the avoided cost DSM/EE savings of the Programs and the savings naturally flowed through in the cost of service study appears to be insignificant, especially in the early years.

Therefore, the Stipulating Parties have agreed that presently, DNCP will not be required to file the calculations made pursuant to the agreed-upon approach in its annual DSM/EE cost and incentive recovery applications. Instead, the Public Staff will be free to evaluate whether an adjustment is necessary as part of its investigation of each annual DSM/EE filing beginning with the 2014 DSM/EE annual filing, including obtaining through the discovery process the information necessary to make the calculations. In any case, the Stipulating Parties shall review the terms and conditions of this 100% cost assignment language at least every three years and shall submit any proposed changes to the Commission for approval.

APPENDIX A
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The foregoing Addendum II Language is agreed and stipulated to this the ___ day of August, 2013.

Virginia Electric and Power Company d/b/a Dominion North Carolina Power

By: ____________________________________

Public Staff – North Carolina Utilities Commission

By: ____________________________________

APPENDIX B
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STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-22, SUB 494
DOCKET NO. E-22, SUB 502
DOCKET NO. E-22, SUB 503

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-22, SUB 494	
In the Matter of Application by Virginia Electric and Power Company, d/b/a Dominion North Carolina Power, for Approval of Demand-Side Management and Energy Efficiency Cost Recovery Rider Pursuant to G.S. 62-133.9 and Commission Rule R8-69	
DOCKET NO. E-22, SUB 502	
In the Matter of Application by Virginia Electric and Power Company, d/b/a Dominion North Carolina Power Pursuant to G.S. 62-133.2 and Commission Rule R8-55 Regarding Fuel And Fuel-Related Costs Adjustments for Electric Utilities	NOTICE TO CUSTOMERS OF CHANGE IN RATES
DOCKET NO. E-22, SUB 503	
In the Matter of Application of Virginia Electric and Power Company, d/b/a Dominion North Carolina Power for Approval of Renewable Energy and Energy Efficiency Portfolio Standard Cost Rider Pursuant to G.S. 62-133.8 and Commission Rule 8-67	

NOTICE IS HEREBY GIVEN that, as required by legislation passed in 2007 by the North Carolina General Assembly, the North Carolina Utilities Commission has authorized Virginia Electric and Power Company, d/b/a Dominion North Carolina

Power (DNCP or Company), to adjust its rates to recover its costs of purchasing renewable energy, its costs of fuel and fuel-related costs, and its costs associated with programs implemented to encourage more efficient use of electricity by its customers. The

Commission's Orders were issued on December 18, 2013, in Docket No. E-22, Subs 503, 502 and 494. These rate adjustments will become effective for usage on and after January 1, 2014.

Renewable Energy and Energy Efficiency Portfolio Standard Rate Increase

The Commission approved DNCP's proposed new Riders RP and RPE designed to recover $1,677,392 associated with its annual obligation to purchase electricity produced by renewable energy resources under North Carolina's Renewable Energy and Energy Efficiency Portfolio Standard (REPS). The rate increase was approved by the Commission after review of DNCP's incremental REPS compliance costs incurred during the period January 1, 2012, through June 30, 2013, and costs projected to be incurred during calendar year 2014. The combined Rider RP and Rider RPE charges result in the following monthly per-account customer charges for usage during calendar year 2014: Residential - $0.37; Commercial - $5.33; and Industrial - $35.93. As approved, DNCP's renewable energy cost recovery rider is not applicable to agreements under the Company's outdoor lighting rate schedules, or for sub-metered service agreements. Additionally, the REPS rider is not applicable to small auxiliary separately metered services provided to a customer on the same property as a residential or other service account. An auxiliary service is defined as a non-demand metered, nonresidential service provided on schedule SGS or SG, at the same premises, with the same service address, and with the same account names as an agreement for which a monthly REPS charge has been applied. To qualify for an auxiliary service, not subject to this rider, the customer must notify the Company and the Company must verify that such service is considered an auxiliary service, after which the REPS billing factor will not be applied to qualifying auxiliary service agreements. The customer shall also be responsible for notifying the Company of any change in service that would no longer qualify the service as auxiliary. Please contact the Company at 1-866-DOM-HELP or 1-866-366-4357, or go to *https://www.dom.com/REPS-opt-out* for additional details on qualifying as an eligible auxiliary service account.

Fuel-Related Rate Increase

The Commission approved a $4,899,151 aggregate increase in DNCP's annual fuel revenues. The rate increase was approved by the Commission after review of the Company's fuel expenses during the 12-month period ended June 30, 2013, and represents changes experienced and expected by the Company with respect to its reasonable costs of fuel and the fuel component of purchased power. DNCP's total net fuel factors for each customer class to be billed during calendar year 2014 are: Residential - 2.561 ¢/kilowatt hour (kWh); SGS & Public Authority - 2.559 ¢/kWh; LGS - 2.540 ¢/kWh; NS - 2.462 ¢/kWh; 6VP - 2.508 ¢/kWh; Outdoor Lighting -

2.561 ¢/kWh; and Traffic - 2.561 ¢/kWh. The foregoing rates are the result of the Commission's approval of a Stipulation of Settlement agreed to by DNCP and the Public Staff – North Carolina Utilities Commission in this proceeding.

Demand-Side Management and Energy Efficiency Related Rate Increase

The Commission approved a $466,930 aggregate increase in DNCP's annual demand-side management and energy efficiency (DSM/EE) program revenues. The rate increase was approved by the Commission after review of the Company's forecasted DSM/EE program expenses and utility incentives for the calendar year 2014 (Rider C) and its true up of its actual costs and revenues received under Rider C rates in effect during the twelve months ending June 30, 2013 (Rider CE). The combined Rider C and Rider CE rates result in the following kWh charges for usage during calendar year 2014: Residential - 0.092 ¢/kWh; SGS & Public Authority - 0.084 ¢/kWh; LGS - 0.106 ¢/kWh; 6VP - 0.091 ¢/kWh; no charge for NS, Outdoor Lighting and Traffic. Commercial customers with annual consumption of 1,000,000 kWh or greater in the prior calendar year, and all industrial customers, may elect not to participate in the Company's DSM/EE programs and thereby avoid paying these charges by notifying the Company that they have implemented or will implement their own DSM or EE measures. Commercial and industrial customers choosing this option will receive an offsetting credit to the DSM/EE rates on their monthly bills. Please go to https://www.dom.com/dominion-north-carolina-power/customer-service/energy-conservation/north-carolina-dsm-commercial-opt-out.jsp for additional details on DSM/EE opt out eligibility.

Summary of Rate Increases

Each of these rate changes will become effective for usage on and after January 1, 2014. The total monthly impact of these rate changes for a residential customer using 1,000 kWh per month is an increase of $1.53, which is approximately a 1.4% increase. The total monthly impact for commercial and industrial customers will vary based upon consumption and customers' participation in the Company's DSM/EE programs.

ISSUED BY ORDER OF THE COMMISSION.
This the 18th day of December, 2013.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

DOCKET NO. G-5, SUB 540

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Public Service Company of North Carolina, Inc. for Annual Review of Gas Costs Pursuant to G.S. 62-133.4(c) and Commission Rule R1-17(k)(6)	)))))	ORDER ON ANNUAL REVIEW OF GAS COSTS

HEARD: Tuesday, August 13, 2013, at 10:00 a.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner Susan W. Rabon, Presiding; Chairman Edward S. Finley, Jr.; and Commissioner Bryan E. Beatty

APPEARANCES:

For Public Service Company of North Carolina, Inc.:

Mary Lynne Grigg, McGuireWoods, LLP, 434 Fayetteville Street, Suite 2600, Raleigh, North Carolina 27601

For the Using and Consuming Public:

Gina C. Holt, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699

BY THE COMMISSION: On May 31, 2013, pursuant to G.S. 62-133.4(c) and Commission Rule R1-17(k)(6), Public Service Company of North Carolina, Inc. (PSNC or Company), filed the direct testimony and exhibits of Candace A. Paton, Rates & Regulatory Manager and Rose M. Jackson, General Manager – Supply & Asset Management, in connection with the annual review of PSNC's gas costs for the twelve-month period ended March 31, 2013.

On June 6, 2013, the Commission issued its Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice. This Order established a hearing date of Tuesday, August 13, 2013, set prefiled testimony dates, and required the Company to give notice to its customers of the hearing on this matter.

On July 18, 2013, PSNC filed a Response to Questions Required by Order Issued on June 28, 2013, in Docket No. G-100, Sub 91 (Docket No. G-100, Sub 91 Responses). Some of the information was filed under seal pursuant to G.S. 132-1.2.

On July 29, 2013, the Public Staff filed the joint direct testimony of Julie G. Perry, Supervisor, Accounting Division; Catherine L. Eastwood, Staff Accountant, Accounting Division; and Jan A. Larsen, Public Utilities Engineer, Natural Gas Division (Public Staff Panel or Panel).

No other party intervened.

On July 30, 2013, PSNC filed a Motion for Admission to have B. Craig Collins appear pro hac vice on behalf of PSNC. The Commission granted this request on July 31, 2013.

On August 8, 2013, PSNC and the Public Staff filed a Joint Motion for Witnesses to be Excused from Appearance at Evidentiary Hearing. On August 9, 2013, the Commission granted the Joint Motion and issued an Order Conditionally Excusing Witnesses from Attending the Hearing.

On August 9, 2013, the Company filed its affidavits of publication.

On August 12, 2013, PSNC filed Responses to Commission Questions Required By Order Issued on August 9, 2013, a correction to the direct testimony of Rose M. Jackson, and a verification of PSNC's Docket No. G-100, Sub 91 Responses. On August 13, 2013, the matter came on for hearing as scheduled. No public witnesses appeared at the hearing. The testimony and exhibits of all Company witnesses and the Public Staff Panel were admitted into evidence without objection.

On September 10, 2013, the Joint Proposed Order of PSNC and the Public Staff was filed.

On September 17, 2013, PSNC filed an Application for Bi-annual Adjustment of Rates Under Rider C of it Tariff and Approval of Temporary Increments in Rates to Recover Fixed Gas Costs Under Rider D to Its Tariff in Docket No. G-5, Sub 542. In that docket, PSNC proposed to implement increments in lieu of the temporary rate adjustments proposed in the instant docket.

On September 30, 2013 the Commission issued a Notice of Decision in the instant docket and gave notice that it would issue an order concluding that: (1) PSNC's accounting for gas costs for the twelve-month period ended March 31, 2013, shall be approved; (2) the gas costs incurred by PSNC during the twelve-month period ended March 31, 2013, were reasonably and prudently incurred, and PSNC shall be authorized to recover 100% of those gas costs; (3) PSNC shall remove the existing temporaries that were implemented in PSNC's last Annual Review of Gas Costs and implement the temporary rate increments proposed by PSNC witness Paton and agreed to by the Public Staff in the instant docket, effective for service rendered on and after October 1, 2013; and (4) PSNC shall coordinate to provide one notice to its customers informing them of the rate changes allowed in the Notice of Decision and the rate changes allowed by the Commission in Docket No. G-5, Sub 542.

On September 30, 2013, the Public Staff presented PSNC's Application for adjustments to PSNC's Riders C and D in Docket No. G-5, Sub 542 at the Commission's Regular Staff Conference. The Public Staff recommended approval of PSNC's proposed adjustments to Riders C and D. On that same date the Commission issued an Order Approving Rate Adjustments in Docket No. G-5, Sub 542.

Based on the testimony and exhibits received into evidence and the entire record in this proceeding, the Commission makes the following:

FINDINGS OF FACT

1. PSNC is a corporation duly organized and existing under the laws of the State of South Carolina, having its principal office and place of business in Gastonia, North Carolina. PSNC operates a natural gas pipeline system for the transportation, distribution, and sale of natural gas to approximately 500,000 winter-peak customers in the State of North Carolina.

2. PSNC is engaged in providing natural gas service to the public and is a public utility as defined in G.S. 62-3(23), subject to the jurisdiction of this Commission.

3. PSNC has filed with the Commission and submitted to the Public Staff all of the information required by G.S. 62-133.4(c) and Commission Rule R1-17(k) and has complied with the procedural requirements of such statute and rule.

4. The review period in this proceeding is the twelve months ended March 31, 2013.

5. During the review period, PSNC incurred total gas costs of $254,154,252, composed of demand and storage charges of $72,229,932, commodity gas costs of $139,705,955, and other gas costs of $42,218,365.

6. In compliance with the Commission's order in Docket No. G-100, Sub 67, the Company credited 75% of the net compensation from secondary market transactions, which amounted to $7,738,842, to its All Customers Deferred Account.

7. On March 31, 2013, the Company had a debit balance of $565,934 in its Sales Customers Only Deferred Account and a debit balance of $8,458,069 in its All Customers Deferred Account.

8. The Company properly accounted for its gas costs incurred during the review period.

9. PSNC's hedging activities during the review period were reasonable and prudent.

10. On March 31, 2013, the Company had a debit balance of $1,606,102 in its Hedging Deferred Account.

11. It is appropriate for the Company to transfer the $1,606,102 debit balance from the Hedging Deferred Account to its Sales Customers Only Deferred Account. Based on this transfer, the combined balance for the Hedging and Sales Customers Only Deferred Accounts is a net debit balance of $565,934.

12. PSNC has adopted a gas supply policy that it refers to as a "best cost" supply strategy. This gas supply policy is based upon three primary criteria: supply security, operational flexibility, and the cost of gas.

13. PSNC has a portfolio of long-term and supplemental short-term supply agreements with a variety of suppliers, including producers and independent marketers.

14. The gas costs incurred by PSNC during the review period were prudently incurred.

15. As a result of this proceeding, the Company should implement the temporary increments proposed by Company witness Paton and agreed to by the Public Staff Panel. The temporary rate adjustments proposed by Company witness Paton in this proceeding are appropriate and have been subsumed into the adjustments proposed by the Company and approved by the Commission in Docket No. G-5, Sub 542.

16. PSNC has complied with the requirements of the Commission's order in Docket No. G-100, Sub 91, and submitted responses to the questions set forth in the Order.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1 - 2

These findings are essentially informational, procedural, or jurisdictional in nature and were not contested by any party. They are supported by information in the Commission's public files and records and the testimony and exhibits filed by the witnesses for PSNC and the Public Staff.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3 - 4

The evidence supporting these findings of fact is contained in the testimony of PSNC witnesses Jackson and Paton and the joint testimony of the Public Staff Panel. These findings are based on G.S. 62-133.4(c) and Commission Rule R1-17(k)(6).

G.S. 62-133.4 requires that PSNC submit to the Commission information and data for an historical twelve-month review period, including PSNC's actual cost of gas, volumes of purchased gas, sales volumes, negotiated sales volumes, and transportation volumes. In addition to such information, Commission Rule R1-17(k)(6)(c) requires that PSNC file weather normalization, sales volume data, workpapers, and direct testimony and exhibits supporting the information filed.

Witness Jackson testified that Rule R1-17(k)(6) requires PSNC to submit to the Commission on or before June 1 of each year certain information with supporting workpapers based on the twelve-month period ending March 31. Witness Jackson indicated that the Company had filed the required information. Witness Paton also indicated that the Company had provided to the Commission and the Public Staff on a monthly basis the gas cost and deferred gas cost account information required by Commission Rule R1-17(k)(5)(c). The Public Staff witnesses stated that the Public Staff had reviewed the monthly deferred gas cost account reports. The Commission concludes that PSNC has complied with the procedural requirements of G.S. 62-133.4(c) and Commission Rule R1-17(k) for the twelve-month review period ended March 31, 2013.

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

The evidence supporting these findings of fact is found in the testimony of PSNC witness Paton and the joint testimony of the Public Staff Panel.

PSNC witness Paton's exhibits reflect demand and storage costs of $72,229,932, commodity costs of $139,705,955, and other gas costs of $42,218,365 for a total of $254,154,252. The Public Staff Panel agreed that total gas costs for the review period ended March 31, 2013, were $254,154,252.

The Public Staff Panel stated that the Company earned $10,318,456 of margin on secondary market transactions, including capacity release transactions and storage management arrangements, during the review period. Of this amount, $7,738,842 was credited to the All Customers Deferred Account for the benefit of ratepayers.

Company witness Paton's prefiled testimony and exhibits reflected a Sales Customers Only Deferred Account credit balance of $1,040,168 (owed from Company to customers) and a debit balance (owed from customers to Company) of $8,458,069 in its All Customers Deferred Account as of March 31, 2013. The Public Staff Panel agreed with the All Customers Deferred account balance. The Public Staff Panel testified that the recommended balance for the Sales Customers Only Deferred Account is the credit balance of $1,040,168, per Paton Exhibit, Schedule 8 plus the transfer of the $1,606,102 debit balance from the hedging deferred account which results in a $565,934 debit balance in PSNC's Sales Customers Only Deferred Account .

Based upon the foregoing, the Commission concludes that the Company properly accounted for its gas costs incurred during the review period. The Commission concludes that the appropriate level of total gas costs for this proceeding is $254,154,252. The Commission further concludes that the appropriate balances of the Company's deferred accounts as of March 31, 2013, are a debit balance of $565,934 in its Sales Customers Only Deferred Account and a debit balance of $8,458,069 in its All Customers Deferred Account.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 9 - 11

The evidence for these findings of fact is contained in the testimony of PSNC witnesses Paton and Jackson and the joint testimony of the Public Staff Panel.

PSNC witness Paton testified that during the review period the Company incurred net costs of $1,606,102 in its Hedging Deferred Account. The Public Staff Panel testified that these costs were composed of: Economic Gains – Closed Positions of ($536,530); Premiums Paid – Closed Positions of $40,400; Premiums Paid – Open Positions of $1,760,780; Brokerage Fees and Commissions of $9,234; Interest on the Brokerage Account of $194; and Interest on the Hedging Deferred Account of $332,025. The Panel also testified that the hedging costs incurred by the Company during the review period represent approximately 0.63% of gas costs or $0.04 per dekatherm (dt), and that PSNC's weighted average hedged cost of gas for the review period was $4.00/dt. The Panel further stated that the average monthly cost per residential customer for hedging is less than $0.22.

PSNC witness Jackson testified that the primary objective of PSNC's hedging program has always been to help mitigate the price volatility of natural gas for PSNC's firm sales customers. She further testified that PSNC's hedging program meets this objective, not by attempting to out-guess the market, but rather by having financial instruments such as call options or futures in place and at a reasonable cost in order to mitigate the impact of unexpected or adverse price fluctuations to its customers.

PSNC witness Jackson stated that PSNC's hedging program currently utilizes call options in order to help control costs while still providing protection from higher prices. Witness Jackson further stated that PSNC limits the cost of the call option to no more than 10% of the underlying commodity price. She also stated that PSNC limits its hedging program to a twelve-month future time period in which to hedge.

Witness Jackson testified that financial hedges are limited to 25% of PSNC's annually estimated firm sales volume, which has been the case for some time. PSNC continues to utilize two models developed by Kase and Company to assist in determining the appropriate time and volume of hedging transactions. The total amount available to hedge is divided equally between the two models.

PSNC witness Jackson further testified that no changes were made to PSNC's hedging program during this review period. Witness Jackson additionally testified that shifts in production, changes in demand, impacts from weather, and changes in environmental or other regulatory policies will have an impact on natural gas prices; and, therefore, PSNC continues to believe that their conservative approach to hedging is a reasonable and prudent way to provide a measure of protection to customers. She stated that PSNC will continue to analyze and evaluate its hedging program and implement changes to that program as warranted.

The Public Staff Panel testified that its review of the Company's hedging activities is a continuous and ongoing analysis and evaluation of the following information: the Company's monthly hedging deferred account reports, detailed source documentation, workpapers supporting the derivation of the maximum targeted hedge volumes for each month, periodic reports on the status of hedge coverage for each month, periodic reports on the market values of the various financial instruments used by the Company to hedge, monthly Hedging Program Status Reports, monthly reports reconciling the Hedging Program Status Report and the hedging deferred account report, minutes from the meetings of SCANA's Risk Management Committee (RMC), minutes from the meetings of the Board of Directors and its committees that pertain to hedging activities, reports and correspondence from the Company's internal and external auditors, hedging plan documents, communications with Company personnel regarding key hedging events and plan modifications under consideration by SCANA's RMC, and testimony and exhibits of the Company's witnesses in the annual review proceeding.

The Public Staff Panel concluded that based on what was reasonably known or should have been known at the time the Company made its hedging decisions affecting the review period, as opposed to the outcome of those decisions, the Panel's analysis led it to the conclusion that the Company's hedging decisions were prudent.

The Public Staff Panel testified that based on their review of the gas costs in this proceeding the $1,606,102 debit balance in the Hedging Deferred Account as of the end of the review period should be transferred to the Sales Customers Only Deferred Account. Based on this testimony, the appropriate balance of the Sales Customers Only Deferred Account as of March 31, 2013, after the transfer should be a debit balance of $565,934, owed to the Company.

Based on the evidence provided above, the Commission finds that PSNC's hedging program has met the objective of contributing to the mitigation of gas price volatility and avoiding rate shock to customers. The Commission agrees with the Public Staff that PSNC's hedging activities during the review period were reasonable and prudent and that the $1,606,102 debit balance in the Hedging Deferred Account as of the end of the review period should be transferred to the Company's Sales Customers Only Deferred Account. The combined balance for the Hedging and Sales Customers Only Deferred Accounts is a debit balance of $565,934.

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

The evidence for these findings of fact is found in the testimony of PSNC witness Jackson and the joint testimony of the Public Staff Panel.

PSNC witness Jackson testified that approximately 50% of PSNC's market is comprised of deliveries to industrial or large commercial customers that either purchase gas from PSNC or transport gas on PSNC's system. According to witness Jackson, many of these customers have the capability to use a fuel other than gas and will use an alternate fuel when it is priced below natural gas. The remainder of the Company's sales is primarily to residential and small commercial customers. Electricity is PSNC's primary competition for these market segments.

PSNC witness Jackson further testified that the most appropriate description of PSNC's gas supply policy is a "best cost" supply strategy, which is based on three primary criteria: supply security, operational flexibility, and cost of gas. PSNC witness Jackson indicated that security of supply is the first and foremost criterion. She stated that this refers to the assurance that the supply of gas will be available when needed. She also testified that supply security is especially important for PSNC's firm customers and is supported by PSNC's diverse portfolio of suppliers, receipt points, purchase quantity commitments, and terms.

PSNC witness Jackson testified that maintaining the necessary operational flexibility in PSNC's gas supply portfolio is the second criterion. Flexibility is needed to facilitate PSNC's ability to react to the unpredictable nature of weather and the changing production levels and operating schedules of PSNC's industrial customers, combined with their ability to switch to alternate fuels. She noted that while each of the supply agreements has different purchase commitments and swing capabilities the gas supply portfolio as a whole must be capable of dealing with the monthly, daily, and hourly changes in the Company's market requirements.

In regard to the third criterion, cost of gas, PSNC witness Jackson testified that PSNC is committed to acquiring the most cost-effective supplies while maintaining the necessary security and operational flexibility to serve the needs of its customers. She noted that in evaluating cost it is important to not only consider the actual commodity cost, but to also consider any fuel and transportation charges, or in the case of peaking or storage services any additional injection, withdrawal, or related fuel charges. She testified that PSNC routinely requests gas supply bids from its suppliers to help ensure PSNC is getting the most cost-effective proposals. Company witness Jackson further stated that PSNC incorporates all of these interrelated strategy components into the development of an overall gas supply portfolio to meet the needs of its customers.

Company witness Jackson testified that PSNC's design-day demand is calculated by SCANA Services Resource Planning personnel using regression analysis, incorporating five years of historical daily throughput data to forecast customer and demand growth. She noted that the model used by PSNC assumes a 50 heating degree day and uses historical weather to estimate peak-day demand. At the hearing, PSNC clarified that the 50 heating degree day figure is based on a 60° Farenheit base temperature.

PSNC witness Jackson stated that the majority of PSNC’s interstate pipeline capacity is obtained from Transcontinental Gas Pipe Line Corporation (Transco), the only interstate pipeline with which PSNC has a direct connection. The Company also has a backhaul transportation arrangement with Transco to deliver gas from pipelines and storage facilities downstream of PSNC’s system, as well as transportation and/or storage service agreements with Dominion Transmission, Incorporated; Columbia Gas Transmission, LLC; Texas Gas Transmission, LLC; and East Tennessee Natural Gas LLC. In addition, PSNC has storage service agreements with Dominion Cove Point LNG, LP; Saltville Gas Storage Company, LLC; and Pine Needle LNG Company, LLC.

Company witness Jackson testified that PSNC contracted for additional pipeline capacity during the review period with Cardinal Pipeline, LLC (Cardinal) for 50,000 dts/day of incremental intrastate capacity for a twenty-year term on Cardinal’s System Expansion Project, which was placed into service on July 1, 2012. Witness Jackson additionally testified that to satisfy additional peak-day needs beginning in the winter of 2013-2014, PSNC acquired 9,633 dts/day of available firm transportation that Transco offered through an open season bidding process posted on its electronic bulletin board. In the posting, Transco announced that it would receive requests for firm transportation service for up to 9,633 dts/day of capacity beginning November 1, 2012. She stated that PSNC submitted a bid for a ten-and-a-half year term at the tariff rate, which was accepted by Transco. Witness Jackson further testified that PSNC also contracted with Transco to acquire 100,000 dts/day of capacity on the Leidy Southeast Expansion Project (Leidy SE) which has an estimated in-service date of December 2015.

Company witness Jackson further stated that Leidy SE will provide an additional 469,000 dts/day of firm transportation from various supply points along Transco’s Leidy line to delivery points terminating at its Zone 4 Market Pool in Alabama, along its mainline system. The project will involve the construction of approximately 28 miles of additional pipe segments, called loops, in Pennsylvania and New Jersey. She testified that Leidy SE will allow PSNC to further diversity its supply portfolio by gaining access to Marcellus Shale supply. Witness Jackson further stated that PSNC's analysis showed the Leidy SE project to be the best-cost alternative to satisfy projected peak-day needs beginning in the winter of 2015-2016.

"Supply security" was listed by PSNC witness Jackson as the "the first and foremost" of the three primary criterion in PSNC's "best cost" supply policy. Witness Jackson testified that Transco is the only interstate pipeline directly connected to PSNC and that PSNC also has backhaul transportation available from Transco to deliver gas from pipelines and storage facilities downstream of PSNC's system.

Company witness Jackson additionally testified that there had been changes to PSNC's level of storage services during the review period. She stated that on September 29, 2011, Transco filed an application with the Federal Energy Regulatory Commission (FERC) to abandon four caverns and to partially abandon service from three others located at Transco's Eminence Storage Field. The application also requested permission to partially abandon the total storage and withdrawal capacity quantities available to customers receiving service from that facility. Witness Jackson testified that the FERC granted the abandonment request on February 7, 2013. Customers amended their service agreements to reflect the revised storage and capacity quantities effective February 28, 2013. She stated that prior to Transco's filing, PSNC Rate Schedule ESS (Eminence Storage Service) service agreements had daily withdrawal entitlements of 95,481 dts/day. Further, as a result of the partial abandonment PSNC's daily withdrawal quantities were reduced by 19,219 dts/day to 76,262 dts/day, with an associated decrease in the charges PSNC pays for this storage service. Witness Jackson additionally stated that this reduction in ESS entitlements does not affect deliverability to PSNC's city gate and therefore should not negatively impact service to PSNC's system.

Witness Jackson further testified that PSNC's Firm Transportation (FT) capacity is supported by a gas supply portfolio of long-term supply contracts with a variety of suppliers, including baseload contracts that provide a fixed volume of gas each day, take or release contracts that provide the flexibility to modify the volumes delivered on a monthly basis, no-notice contracts that provide the flexibility to increase or decrease volumes on a daily basis, and spot market contracts that provide for daily purchase of gas. According to witness Jackson, PSNC had approximately 237,000 dts/day under term contracts with six producers and six independent marketers as of November 1, 2012, the beginning of the winter heating season for the period under review. She testified that the contracts all have provisions to ensure that the prices paid are market based.

PSNC witness Jackson testified to the following activities that PSNC has engaged in to lower gas costs while maintaining security of supply and delivery flexibility:

1. PSNC continues to evaluate various FT and storage capacity options to ensure that future peak day and seasonal durational requirements will be met. As discussed above, PSNC entered into various agreements for transportation and storage capacity to meet growing peak demand on its system.

2. PSNC continues to optimize the flexibility available within its supply and capacity contracts to realize their value.

3. PSNC participated in matters before the FERC whose actions could impact PSNC’s rates and services to its customers.

4. PSNC has continued to work with its industrial customers to transport customer-owned gas.

5. PSNC routinely communicates directly with customers, suppliers, and other industry participants, and actively monitors developments in the industry.

6. PSNC has frequent internal discussions among members of its senior management and that of its parent concerning gas supply policy and major purchasing decisions.

7. PSNC utilizes deferred gas cost accounting to calculate the Company’s benchmark cost of gas to provide a smoothing effect on the gas volatility.

8. PSNC conducts a hedging program to help mitigate price volatility.

The Public Staff Panel stated that they had reviewed the testimony and exhibits of the Company's witnesses; monthly operating reports; gas supply and pipeline transportation and storage contracts; and the Company's responses to the Public Staff's data requests. The Public Staff Panel concluded that, based on their investigation and review of the data in this docket, PSNC’s gas costs were prudently incurred.

The Public Staff Panel also concluded that after its review of PSNC’s responses to Public Staff data requests, the Public Staff believes that PSNC has accurately calculated its peak design day demand and customer load profiles. The Panel testified that it had also independently calculated the customer load profile and peak design day demand using current (review period) data and arrived at very similar results.

In addition, after the Panel reviewed the Company’s data request responses, it agreed that PSNC had fully discussed the competitive solicitation that it undertook in arriving at its decision to acquire additional capacity and supply during the review period.

The Commission concludes that the gas costs incurred by PSNC during the test period ended March 31, 2013, were reasonable and prudently incurred and that the Company should be permitted to recover 100% of its prudently incurred gas costs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The evidence for this finding of fact is found in the testimony of PSNC witness Paton and the joint testimony of the Public Staff Panel.

Company witness Paton testified that the Company was proposing new temporary increments applicable to both the All Customers Deferred Account and the Sales Customers Only Deferred Account.

The Public Staff Panel testified that they agree with PSNC’s calculated increment applicable to the Sales Customers Only Deferred Account and the calculated increments applicable to the All Customers Deferred Account contained in Company witness Paton's testimony and exhibits. The Public Staff witnesses also testified that they recommend removal of the existing temporaries that were implemented in PSNC’s last Annual Review of Gas Costs proceeding and implementation of the temporaries recommended in the instant docket. The Public Staff witnesses additionally testified that PSNC calculated a Sales Customers Only temporary increment of $0.0122/dt ($0.00122/therm) based on a March 31, 2013, deferred account debit balance (owed from customers to Company) of $565,934. Since it is anticipated that the Sales Customers Only Deferred Account may be shifting in July 2013 from a debit balance to a credit balance (owed from Company to customers), the Public Staff recommended that, if needed, PSNC adjust its deferred account balance by implementing a new temporary increment or decrement through the Purchased Gas Cost (PGA) mechanism that is available for use by the Company.

Based upon the foregoing, the Commission concludes that it is appropriate for PSNC to remove all temporary rates that were implemented in Docket No. G-5, Sub 533, and implement the temporary increments as proposed by Company witness Paton and agreed to by the Public Staff Panel. The Commission further concludes that, if needed, PSNC should adjust its deferred account balance at any point during the upcoming review period by implementing a new temporary increment or decrement through the PGA mechanism that is available for use by the Company.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

The evidence for this finding of fact is found in PSNC’s Docket No. G-100, Sub 91 Responses.

In its Order Requiring Reporting issued on June 28, 2013, in Docket No G-100, Sub 91 the Commission directed each LDC to file in its Annual Review of Gas Costs responses to nine questions. In addition, each LDC was to explicitly address what steps, if any, it took during the review period to seek out service agreements from competitive supplies pursuant to the provisions of G.S. 62-32B.

On July 18, 2013, PSNC filed responses in the instant docket that were required pursuant to the Commission's Order Requiring Reporting issued on June 28, 2013, in Docket No. G-100, Sub 91 – Investigation Regarding Competition for Additional Natural Gas Service Agreements. The Public Staff Panel testified that it had already explored these same issues in data requests sent to PSNC early in this proceeding, and that it concluded that PSNC has adequately responded to the Order Requiring Reporting.

Based on the foregoing, the Commission concludes that PSNC has complied with the requirements of the Commission's Order Requiring Reporting in Docket No. G-100, Sub 91, and submitted responses to the questions set forth in the Order. The Commission appreciates PSNC's responses. The Commission notes, however, that in this annual review of gas costs the Commission has not attempted to assess the reasonableness or prudence of PSNC's actions in obtaining additional pipeline or storage capacity.

IT IS, THEREFORE, ORDERED as follows:

1. That PSNC's accounting for gas costs for the twelve-month period ended March 31, 2013, is approved;

2. That the gas costs incurred by PSNC during the twelve-month period ended March 31, 2013, were reasonably and prudently incurred, and PSNC is hereby authorized to recover 100% of these gas costs as provided herein;

3. That PSNC shall make the rate adjustments approved by the Commission in the Order Approving Rate Adjustments in Docket No. G-5, Sub 542; and

4. That PSNC shall give one notice to its customers of the rate changes allowed in this Order and in the Order Approving Rate Adjustments in Docket No. G-5, Sub 542.

ISSUED BY ORDER OF THE COMMISSION.
This the 10th day of October, 2013.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

eb101013.01

DOCKET NO. G-9, SUB 633

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Piedmont Natural Gas Company, Inc., for Annual Review of Gas Costs Pursuant to G.S. 62-133.4(c) and Commission Rule R1-17(k)(6)	))))	ORDER ON ANNUAL REVIEW OF GAS COSTS

HEARD: Tuesday, October 1, 2013, at 10:00 a.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner Susan W. Rabon, Presiding, Commissioners ToNola D. Brown-Bland and James G. Patterson

APPEARANCES:

For Piedmont Natural Gas Company, Inc.:

James H. Jeffries IV, Moore & Van Allen PLLC, Bank of America Corporate Center, 100 N. Tryon Street, Suite 4700, Charlotte, North Carolina 28202

For the Using and Consuming Public:

Elizabeth A. Denning, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699

BY THE COMMISSION: On August 1, 2013, pursuant to G.S. 62-133.4(c) and Commission Rule R1-17(k)(6), Piedmont Natural Gas Company, Inc. (Piedmont or Company), filed the direct testimonies and exhibits of Frank Yoho, Senior Vice President and Chief Commercial Operations Officer; Keith P. Maust, Managing Director, Gas Supply and Scheduling; Robert L. Thornton, Director of Gas and Regulatory Accounting; and Sarah E. Stabley, Director of Gas Supply, Scheduling and Optimization, attesting to the prudence of the Company's gas purchasing policies and the accuracy of the Company's gas cost accounting for the twelve-month period ended May 31, 2013.

On August 2, 2013, the Commission issued its Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines and Requiring Public Notice. The Order established a hearing date of Tuesday, October 1, 2013, set prefiled testimony dates and discovery guidelines, and required the Company to give notice to its customers of the hearing on this matter.

On August 6, 2013, Carolina Utility Customers Association, Inc., filed a Petition to Intervene, which was granted by the Commission on August 13, 2013.

On September 16, 2013, the Public Staff filed the joint testimony and exhibit of Michelle M. Boswell, Staff Accountant, Accounting Division; Julie G. Perry, Supervisor, Natural Gas Section, Accounting Division; and, Jeffrey L. Davis, Director, Natural Gas Division (Public Staff Panel).

On September 23, 2013, Piedmont and the Public Staff filed a Joint Motion for Witnesses to be Excused from Appearance at the evidentiary hearing and requested that the pre-filed testimony and exhibits of all witnesses be received into the record without requiring the appearance of such witnesses. The Commission granted the joint motion on September 26, 2013.

On September 25, 2013, the Company filed its affidavits of publication.

On October 1, 2013, the matter came on for hearing as scheduled, and all prefiled testimony and exhibits were admitted into evidence. No public witnesses appeared at the hearing.

Based on the testimony and exhibits received into evidence and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

1. Piedmont is a public utility as defined in Chapter 62 of the North Carolina General Statutes.

2. Piedmont is engaged primarily in the business of transporting, distributing, and selling natural gas to customers in North Carolina, South Carolina, and Tennessee.

3. Piedmont has filed with the Commission and submitted to the Public Staff all of the information required by G.S. 62-133.4(c) and Commission Rule R1-17(k)(6).

4. The review period in this proceeding is the twelve months ended May 31, 2013.

5. The Company has properly accounted for its gas costs incurred during the review period.

6. During the review period, the Company incurred total costs of gas expensed of $348,581,333, which was comprised of demand and storage charges of $119,461,813, commodity gas costs of $247,530,406, and other gas costs of ($18,410,886).

7. On May 31, 2013, the Company had a debit balance of $16,132,324 in its All Customers Deferred Account and a credit balance of $4,995,340 in its Sales Customers Only Deferred Account.

8. Piedmont actively participated in secondary market transactions, earning $23,630,298 of margin for the benefit of ratepayers.

9. Piedmont operated a gas cost hedging program on behalf of customers during the review period. Piedmont's hedging activities during the review period were reasonable and prudent.

10. On May 31, 2013, the balance in the Company's Hedging Deferred Account was a debit balance of $1,883,661.

11. It is appropriate for the Company to transfer the $1,883,661 debit balance in its Hedging Deferred Account to its Sales Customers Only Deferred Account. The combined balance for the Hedging and Sales Customers Only Deferred Accounts is a credit balance of $3,071,679.

12. The Company has transportation and storage contracts with interstate pipelines, which provide for the transportation of gas to the Company's system, and long-term supply contracts with producers, marketers, and other suppliers.

13. The Company utilized a "best cost" gas purchasing policy during the applicable review period consisting of five main components: price of gas, security of the gas supply, flexibility of the gas supply, gas deliverability, and supplier relations.

14. Piedmont has complied with the requirements of the Commission's Order in Docket No. G-100, Sub 91 (Sub 91 Order), and submitted responses to the questions set forth in the Order.

15. The Company's gas purchasing policy and practices during the review period were prudent.

16. The Company's gas costs during the review period were prudently incurred, and the Company should be permitted to recover 100% of such prudently incurred gas costs.

17. The Company should implement the temporary rate decrement applicable to the Sales Customers Only Deferred Account and the temporary rate increments applicable to the All Customers Deferred Account proposed by Company witness Thornton and agreed to by the Public Staff Panel.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1 - 2

The evidence supporting these findings of fact is contained in the official files and records of the Commission and the testimony of Company witnesses Yoho, Maust, Thornton, and Stabley. These findings are essentially informational, procedural, or jurisdictional in nature and are based on uncontested evidence.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3 - 4

The evidence supporting these findings of fact is contained in the testimony of Company witnesses Yoho, Maust, Thornton, and Stabley, and the joint testimony of the Public Staff Panel. These findings are based on G.S. 62-133.4(c) and Commission Rule R1-17(k)(6).

G.S. 62-133.4(c) requires that each natural gas utility submit to the Commission information and data for an historical twelve-month review period concerning its actual cost of gas, volumes of purchased gas, sales volumes, negotiated sales volumes, and transportation volumes. Commission Rule R1-17(k)(6)(a) establishes May 31, 2013, as the end date of the review period for the Company in this proceeding. Commission Rule R1-17(k)(6)(c) requires the filing by the Company of certain information and data showing weather-normalized sales volumes, workpapers, and direct testimony and exhibits supporting the information.

Company witness Thornton testified that the Company filed with the Commission and submitted to the Public Staff throughout the review period complete monthly accountings of the computations required by Commission Rule R1-17(k)(6)(c). Witness Thornton included the annual data required by Commission Rule R1-17(k)(6)(c) as Exhibit_(RLT-1) to his direct testimony. The Public Staff Panel stated that they had presented the results of their review of the gas cost information filed by Piedmont in accordance with G.S. 62-133.4(c) and Commission Rule R1-17(k)(6). The Commission concludes that Piedmont has complied with the procedural requirements of G.S. 62-133.4(c) and Commission Rule R1-17(k)(6) for the twelve-month review period ended May 31, 2013.

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

The evidence supporting these findings of fact is contained in the testimony of Company witness Thornton and the Public Staff Panel.

Company witness Thornton testified that Piedmont incurred total costs of gas expensed of $348,581,333 during the review period, which was comprised of demand and storage charges of $119,461,813, commodity gas costs of $247,530,406, and other gas costs of ($18,410,886).

Company witness Thornton's prefiled testimony and exhibit reflected a Sales Customers Only Deferred Account credit balance of $4,995,340 and an All Customers Deferred Account debit balance of $16,132,324 as of May 31, 2013. The Public Staff Panel agreed with these balances and testified that the Company properly accounted for its gas costs incurred during the review period.

Based upon the foregoing, the Commission concludes that the Company properly accounted for its gas costs incurred during the review period. The Commission concludes that the appropriate level of total costs of gas expensed for this proceeding is $348,581,333. The Commission further concludes that the appropriate balances of the Company's deferred accounts as of May 31, 2013, are a credit balance of $4,995,340 in its Sales Customers Only Deferred Account and a debit balance of $16,132,324 in its All Customers Deferred Account.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence supporting this finding of fact is contained in the testimony of Company witnesses Stabley and Thornton and the Public Staff Panel.

Company witness Stabley provided testimony on the process that Piedmont utilized and the market intelligence that was evaluated during the review period to determine the prices charged for off-system sales. Witness Stabley explained that the process and information used by Piedmont in pricing off-system sales depends on the term and type of sale, and prevailing market conditions at the time of sale. Witness Stabley stated that for long-term delivered sales (longer than one month), Piedmont solicits bids from potential buyers and awards volumes based on bids received. Witness Stabley further stated that for short-term transactions (daily or monthly) Piedmont monitors prices and volumes on the Intercontinental Exchange, as well as by talking to various market parties and, for less liquid trading points, estimating prices based on price relationships with more liquid points. The Company also evaluates the amount of supply available for sale and weighs that against current market conditions in formulating its sales strategy.

The Public Staff Panel testified that the Company earned actual margins of $37,512,875 on secondary market transactions and credited the All Customers Deferred Account in the amount of $23,630,298 for the benefit of ratepayers ($37,512,875 x 83.99% NC demand allocator x 75% ratepayer sharing percent). The actual margins were a result of Piedmont's participation in asset management arrangements, capacity releases, and off-system sales.

Based on the foregoing, the Commission concludes that Piedmont actively participated in secondary market transactions, earning $23,630,298 of margin for the benefit of ratepayers during the review period.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 9 - 11

The evidence supporting these findings of fact is contained in the testimony of Company witnesses Maust and Thornton and the Public Staff Panel.

Company witness Thornton stated in his testimony that the Company had a total debit balance of $1,883,661 in its Hedging Deferred Account on May 31, 2013. The Public Staff Panel testified that the hedging costs were composed of Economic (Gain)/Loss – Closed Positions of $0, Premiums Paid – Closed Positions of $94,660, Premiums Paid – Open Positions of $1,303,990, Brokerage Fees and Commissions of $16,694, and Interest on the Hedging Deferred Account of $468,317.

Company witness Maust testified that Piedmont's Hedging Plan accomplished its goal of protecting customers in North Carolina in the event of sudden increases in the price of gas. Witness Maust stated the Company did not make any changes to its Hedging Plan during the review period. Witness Maust stated that the Company continues to utilize storage as a physical hedge to stabilize cost, and that the Company's Equal Payment Plan and the use of the Purchased Gas Adjustment benchmark price and deferred cost accounting also allowed for a smoothing effect on gas price volatility.

The Public Staff Panel testified that the Public Staff's review of the Company's hedging activities is performed on an ongoing basis and includes analysis and evaluation of the Company's monthly hedging deferred account reports, detailed source documentation, workpapers supporting the derivation of the maximum targeted hedge volumes for each month, periodic reports on the status of hedge coverage for each month, periodic reports on the market values of the various financial instruments used by the Company to hedge, monthly Hedging Program Status Reports, monthly reports reconciling the Hedging Program Status Report and the hedging deferred account report, minutes from the meetings of Piedmont's Energy Price Risk Management Committee (EPRMC), minutes from the meetings of the Board of Directors and its committees that pertain to hedging activities, reports and correspondence from the Company's internal and external auditors, hedging plan documents, communications with Company personnel regarding key hedging events and plan modifications under consideration by the EPRMC, and the testimony and exhibits of the Company's witnesses in the annual proceeding.

The Public Staff Panel concluded that Piedmont's hedging activities were reasonable and prudent and recommended that the $1,883,661 debit balance in the Hedging Deferred Account as of the end of the review period be transferred to the Sales Customers Only Deferred Account. Based on this recommendation, the balance of the Sales Customers Only Deferred Account as of May 31, 2013, should be a credit balance of $3,071,679.

As demonstrated by the testimony and exhibits provided by Piedmont and the Public Staff Panel, the Commission finds that Piedmont's hedging program has met the objective of contributing to the mitigation of gas price volatility and avoiding rate shock to customers. The Commission concludes that Piedmont's hedging activities were reasonable and prudent and that the $1,883,661 debit balance in the Hedging Deferred Account as of the end of the review period should be transferred to the Sales Customers Only Deferred Account. The combined balance for the Hedging and Sales Customers Only Deferred Accounts is a credit balance of $3,071,679.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12 - 16

The evidence supporting these findings of fact is contained in the testimony of Company witnesses Stabley, Maust, and Yoho, and the Public Staff Panel.

Company witness Stabley testified that the Company maintains a "best cost" gas purchasing policy. This policy consists of five main components: price of the gas; security of the gas supply; flexibility of the gas supply; gas deliverability; and, supplier relations. Witness Stabley testified that all of these components are interrelated and that the Company weighs the relative importance of each of these five factors in developing its overall gas supply portfolio to meet the needs of its customers.

Witness Stabley further testified that the Company purchases gas supplies under a diverse portfolio of contractual arrangements with a number of reputable gas producers and marketers. Under its firm gas supply contracts, Piedmont pays negotiated reservation fees for the right to reserve and call on firm supply service up to a maximum daily contract quantity (nominated either on a monthly or daily basis), with market-based commodity prices tied to indices published in industry trade publications. Some of these firm contracts are for winter only (peaking or seasonal) service and some provide for 365 day (annual) service. Firm gas supplies are purchased for reliability and security of service and are generally priced on a reservation fee basis according to the amount of nomination flexibility built into the contract (daily swing service generally being more expensive than monthly baseload service). Witness Stabley testified that the Company identifies the volume and type of supply that it needs to fulfill its market requirements and solicits requests for proposals from a list of suppliers that the gas supply department continuously updates as potential suppliers enter and leave the market place. The type of supply is classified as either baseload or swing and as either firm or interruptible. Witness Stabley stated that swing supplies priced at first of month indices command the highest reservation fees because suppliers incur all the price risk associated with market volatility during the delivery period. Keep-whole contracts require the Company to reimburse suppliers for the difference between first of the month index prices and lower daily market prices if the Company does not take its full contractual volume. Witness Stabley testified that because the Company assumes the volatility risk associated with falling prices, a lower reservation fee is warranted. Lower reservation fees are also associated with swing contracts based upon daily market conditions since both buyer and seller assume the risk of daily market volatility. Witness Stabley stated that the Company evaluates the cost of the reservation fees associated with each type of supply and its corresponding bid, and makes a “best cost” decision on which type of supply and supplier to fulfill its needs. Company witness Stabley also testified regarding the current U.S. supply situation and the various pricing alternatives available, such as fixed prices, monthly market indexing, and daily spot market pricing.

Witness Stabley also described how the interrelationship of the five factors affects the Company’s construction of its gas supply and capacity portfolio under its best cost policy. The long-term contracts, supplemented by long-term peaking services and storage, generally are aligned with the firm market; the short-term spot gas generally serves the interruptible market. In order to weigh and consider the five factors, the Company must be kept informed about all aspects of the natural gas industry. The Company, therefore, stays abreast of current issues by intervening in all major Federal Energy Regulatory Commission (FERC) proceedings involving its pipeline transporters, maintaining constant contact with existing and potential suppliers, monitoring gas prices on a real-time basis, attending industry seminars, subscribing to industry literature, and following supply and demand developments. Witness Stabley further testified that the Company did not make any changes in its best cost gas purchasing policies or practices during the test period. Witnesses Maust and Stabley also indicated that during the past year the Company has taken several additional steps to manage its costs, including actively participating in proceedings at the FERC and other regulatory agencies that could reasonably be expected to affect the Company’s rates and services, promoting more efficient peak day use of its system, and utilizing the flexibility within its existing supply and capacity contracts to purchase and dispatch gas, and release capacity in the most cost effective manner.

Company witness Maust testified in accordance with the Sub 91 Order regarding the market requirements of Piedmont’s North Carolina customers and the acquisition of capacity to serve those markets. Witness Maust also testified that unlike previous years, the Company experienced an increase in normalized usage per customer during the review period. Maust attributed the increased normalized usage to customers becoming increasingly more comfortable with the low commodity cost of gas and a decreased concern about implementing conservation measures, an increased priority on comfort and an improving economy. Witness Maust further testified that Piedmont and the natural gas industry have not seen evidence that conservation/reduced usage occurs during design day conditions. For that reason, witness Maust testified that Piedmont will continue to utilize a conservative approach to design day forecasting until more comprehensive data indicates that another approach is appropriate.

In accordance with the Sub 91 Order, Company witness Yoho also provided a detailed description of Piedmont's current capacity levels and its capacity acquisition activities and strategy. Witness Yoho testified that most of the Company's more recent capacity additions have focused on meeting seasonal and peak day needs rather than firm year-round baseload requirements. Witness Yoho also further testified that Piedmont carefully pursues and evaluates all available options when it seeks to acquire new interstate capacity to serve its firm customers' needs, including any proposed new projects that might be capable of delivering additional volumes of natural gas into North Carolina on a competitive basis. Witness Yoho testified that the Company has investigated several potential capacity additions during the review period but that none of these potential capacity additions have posed a realistic prospect for the construction of a new interstate pipeline directly serving North Carolina.

Witness Maust testified that Piedmont does not maintain capacity that is truly "excess" to the Company's needs. Piedmont's need to maintain both adequate design day capacity and a reserve margin are the result of several factors. It is commercially impossible for Piedmont to sculpt supply and capacity rights to perfectly match the Company's projected needs on a seasonal or year round basis. Witness Maust stated that capacity additions are acquired in "blocks" of additional transportation, storage, or LNG capacity, as they become needed, to ensure Piedmont's ability to serve its customers based on the options available at that time. Witness Maust explained that as a practical matter this means that at any given moment in time Piedmont's actual capacity assets will vary somewhat from its forecasted capacity requirements. Witness Maust also stated that this aspect of capacity planning is unavoidable but Piedmont attempts to mitigate the impact of any mismatch through its use of bridging services, capacity release and off-system sales activities.

Company witness Maust further testified that Piedmont's design day calculation involves several elements, including: (1) the actual throughput and degree days experienced on the most recent day that approached the design day temperature; (2) the day's interruptible sales; (3) the day's actual firm and interruptible transportation quantities; (4) the dekatherm per degree day factor generated from several sources, including data that resides in the forecast software program "GASDAY"; and, (5) the forecasted number of heat sensitive sales customers expected during the upcoming heating season. Piedmont recalculates its design day annually, and each yearly design day forecast is derived by multiplying the temperature sensitive rate classes' usage for the previous year by the succeeding year's forecasted growth percentage. Witness Maust testified the Company constructs load duration curves that forecast the Company's firm sales market requirements for normal winter weather conditions and design day winter weather conditions. The capacity requirements are plotted in descending order of magnitude, with existing pipeline capacity and storage resources overlaid to expose any supply shortfalls. Witness Maust provided the forecast load duration curves in Exhibit_(KPM-1) and

Exhibit_(KPM-2). Witness Maust also provided the design day calculation for the review period and forecasted winter heating seasons in Exhibit_(KPM-3).

The Public Staff Panel testified that they had reviewed the testimony and exhibits of the Company's witnesses, the monthly operating reports, and the gas supply and pipeline transportation and storage contracts, as well as the Company's responses to the Public Staff's data requests. Based on this review, the Public Staff Panel testified that the Company's review period gas costs were prudently incurred.

The Public Staff Panel further testified that although the scope of Commission Rule R1-17(k) is limited to a historical review period, they also considered other information in order to anticipate the Company's requirements for future needs, including design day estimates, forecasted gas supply needs, projection of capacity additions and supply changes, and customer load profile changes.

Based on the foregoing, the Commission concludes that the Company's gas costs incurred during the review period were reasonable and prudently incurred and that the Company should be permitted to recover 100% of its prudently incurred gas costs.

The Commission further concludes that Piedmont has complied with the requirements of the Sub 91 Order and submitted responses to the questions set forth in the Sub 91 Order through its testimony. The Commission appreciates Piedmont's responses. The Commission notes, however, that in this annual review of gas costs the Commission has not attempted to assess the reasonableness or prudence of Piedmont's actions in obtaining additional pipeline or storage capacity.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 17

The evidence supporting this finding of fact is contained in the testimony of Company witness Thornton and the Public Staff Panel.

Company witness Thornton stated in his testimony that based on the Company's deferred accounts end-of-period balances, as reflected on Thornton Exhibit_(RLT-3) and Exhibit_(RLT-4), he recommended that the increments and decrements to Piedmont's rates be placed into effect for a period of twelve months after the effective date of the final order in this proceeding. The Public Staff Panel testified that they had calculated the temporary rate increments applicable to the All Customers Deferred Account balance and the temporary rate decrement applicable to the Sales Customers Only Deferred Account, and their calculations agreed with those proposed by Company witness Thornton. The Public Staff Panel recommended that Piedmont monitor the balances in both the All Customers and Sales Customers Only Deferred Accounts, and, if needed, Piedmont should adjust its deferred account balances by implementing a new temporary increment or decrement through the Purchased Gas Adjustment (PGA) procedures that are available for use by the Company.

Based on the foregoing, the Commission concludes that it is appropriate for the Company to remove the temporary rates that were implemented for the All Customers Deferred Account and the Sales Customers Only Deferred Account in Docket No. G-9, Sub 614, and implement the temporary rate increments applicable to the All Customers Deferred Account and the temporary rate decrement applicable to the Sales Customers Only Deferred Account as proposed in Thornton Exhibit_(RLT-3) and Exhibit_(RLT-4). The Commission further concludes that, if needed, Piedmont should adjust its deferred account balance at any point during the upcoming review period by implementing a new temporary increment or decrement through the PGA procedures that are available for use by the Company.

IT IS, THEREFORE, ORDERED as follows:

1. That the Company's accounting for gas costs during the twelve-month period ended May 31, 2013, is approved;

2. That the gas costs incurred by Piedmont during the twelve-month period ended May 31, 2013, were reasonably and prudently incurred, and Piedmont is hereby authorized to recover 100% of its gas costs incurred during the period of review;

3. That the Company shall remove the existing temporaries that were implemented in Docket No. G-9, Sub 614, and implement the temporary rate increments and decrement for the All Customers and Sales Customers Only Deferred Accounts, respectively, as found appropriate herein, effective for service rendered on and after the first day of the month following the date of this Order; and

4. That Piedmont shall give notice to its customers of the rate changes allowed in this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 12th day of November, 2013.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

DOCKET NO. G-41, SUB 37

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Toccoa Natural Gas for	)	
Annual Review of Gas Costs Pursuant to	)	ORDER ON ANNUAL REVIEW
G.S. 62-133.4(c) and Commission	)	OF GAS COSTS
Rule R1-17(k)(6)	)	

HEARD: Wednesday, November 6, 2013, at 10:00 a.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner Susan W. Rabon, Presiding, and Commissioners Bryan E. Beatty and Jerry C. Dockham

APPEARANCES:

For Toccoa Natural Gas:

Charlotte A. Mitchell, Styers, Kemerait & Mitchell, 1101 Haynes Street, Suite 101, Raleigh, North Carolina 27604

For the Using and Consuming Public:

Elizabeth A. Denning, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699

BY THE COMMISSION: On September 3, 2013, Toccoa Natural Gas (Toccoa or Company), filed the direct testimony and exhibits of Rai Trippe, Member Support Senior Business Analyst for the Municipal Gas Authority of Georgia (Gas Authority), and Harry F. Scott, Jr., Utilities Director for Toccoa, in connection with the annual review of Toccoa's gas costs pursuant to G.S. 62-133.4(c) and Commission Rule R1-17(k)(6), for the 12-month period ended June 30, 2013.

On September 9, 2013, the Commission issued its Order Scheduling Hearing, Establishing Filing Dates and Discovery Guidelines, and Requiring Public Notice. This Order established a hearing date of November 6, 2013, set pre-filed testimony dates, and required Toccoa to give at least 30 days prior notice to its customers of the hearing on this matter.

On October 18, 2013, Toccoa filed its responses to the Commission's directive in its Order Requiring Reporting issued June 28, 2012, in Docket No. G-100, Sub 91 (Sub 91 Order). Toccoa filed Exhibit A attached to its responses under seal as confidential trade secret information.

On October 21, 2013, the Public Staff filed the direct testimony of Richard C. Ross, Utilities Engineer, Natural Gas Division, and Julie G. Perry, Supervisor, Natural Gas Section, Accounting Division.

On October 22, 2013, Toccoa and the Public Staff filed a Joint Motion to Excuse Witnesses and Accept Testimony, which was granted by the Commission on October 24, 2013.

On October 29, 2013, Toccoa filed its Affidavit of Publication.

On November 6, 2013, the matter came on for hearing as scheduled, and all prefiled testimony and exhibits were admitted into evidence. No public witnesses appeared at the hearing.

On November 8, 2013, Toccoa filed a letter informing the Commission that Exhibit A to its October 18, 2013 filing does not contain confidential information and to request that the record of the evidentiary hearing held on November 6, 2013 reflect the change in designation. Toccoa also filed a copy of its October 18, 2013 filing that was not stamped confidential and requested that it be included in the record in lieu of the filing previously made.

Based on the testimony, exhibits, and the entire record in this proceeding, the Commission makes the following:

FINDINGS OF FACT

1. Toccoa, a division of the City of Toccoa, Georgia, is a public utility as defined by G.S. 62-3(23) and, as such, is subject to the jurisdiction of the Commission.

2. Toccoa is primarily engaged in the business of purchasing, transporting, distributing, and selling natural gas to approximately 6,350 customers in Georgia and North Carolina, of which approximately 608 are in North Carolina. Toccoa is a full requirements wholesale customer of the Municipal Gas Authority of Georgia (Gas Authority).

3. The Company has filed with the Commission and submitted to the Public Staff all information required by G.S. 62-133.4(c) and Commission Rule R1-17(k) and has complied with the procedural requirements of the statute and rule.

4. The review period in this proceeding is the 12 months ended June 30, 2013.

5. During the review period, Toccoa incurred total North Carolina gas costs of $460,933, which was comprised of demand and storage costs of $100,413, commodity costs of $281,601, and other gas costs of $78,919.

6. On June 30, 2013, Toccoa had a credit balance of $14,379 owed by Toccoa to customers in its North Carolina Deferred Gas Cost Account (NC Deferred Account).

7. Toccoa properly accounted for its gas costs during the review period.

8. Toccoa's hedging activities during the review period were reasonable and prudent.

9. Toccoa has transportation and storage contracts with interstate pipelines that provide for the transportation of gas to Toccoa's system and an "all requirements" gas supply contract with the Gas Authority.

10. Toccoa released unutilized capacity during the review period to mitigate the cost of demand capacity, and all margins earned on secondary market transactions reduced the cost of gas and were flowed through to ratepayers.

11. Toccoa has adopted a "portfolio approach" gas purchasing policy that consists of four main components: long-term firm supply, short-term spot market purchases, seasonal peaking, and contract storage services.

12. Toccoa's gas purchasing policy and practices during the review period were prudent, and its gas costs during the review period were prudently incurred.

13. Toccoa should be permitted to recover 100% of its prudently incurred gas costs.

14. As a result of this proceeding, the Company should implement the temporary rate increment of $0.5806 per dekatherm (dt) proposed by Public Staff witness Ross and agreed to by Toccoa.

15. Toccoa has complied with the requirements of the Commission's Order in Docket No. G-100, Sub 91, and submitted responses to the questions set forth in the Order.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1 – 2

The evidence supporting these findings of fact is contained in the official files and records of the Commission, the testimony and exhibits of Toccoa witnesses Trippe and Scott, and the testimony of Public Staff witness Ross. These findings are essentially informational, procedural or jurisdictional and are based on uncontested evidence.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3 - 4

The evidence supporting these findings of fact is contained in the testimony of Toccoa witness Trippe and the testimony of Public Staff witnesses Ross and Perry.

G.S. 62-133.4(c) requires that each natural gas utility submit to the Commission information and data for a historical 12-month review period concerning its actual cost of gas, volumes of purchased gas, sales volumes, negotiated sales volumes, and transportation volumes. Commission Rule R1-17(k)(6)(c) requires the filing by Toccoa of certain information and data showing weather-normalized sales volumes, workpapers, and direct testimony and exhibits supporting the information.

Toccoa witness Trippe testified that he was not aware of any outstanding issues regarding the reporting requirements of Rule R1-17(k)(5)(c), which requires the Company to file a complete monthly accounting of computations for gas costs and deferred account activity.

Public Staff witnesses Ross and Perry confirmed that the Public Staff had reviewed the filings and monthly reports filed by Toccoa.

The Commission concludes that Toccoa has complied with all procedural requirements of G.S. 62-133.4(c) and Commission Rule R1-17(k) for the 12-month review period ended June 30, 2013.

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

The evidence supporting these findings of fact is contained in the testimony of Toccoa witness Trippe and Public Staff witness Perry.

Company witness Trippe testified that Toccoa incurred total North Carolina gas costs of $460,933 during the review period, which was comprised of demand and storage costs of $100,413, commodity costs of $281,601, and other gas costs of $78,919. Public Staff witness Perry testified that every month the Public Staff reviews the NC Deferred Account reports filed by Toccoa for accuracy and reasonableness, and performs audit procedures on the calculations. Witness Perry also testified that Toccoa had properly accounted for its gas costs during the review period.

Public Staff witness Perry stated that Toccoa operates in both Georgia and North Carolina. Witness Perry further testified that the Company maintains the NC Deferred Account, which is one deferred gas cost account for North Carolina that includes both commodity and demand gas charges incurred and recovered during each review period. She explained that Toccoa allocates the deferred gas cost account balance to North Carolina based on the monthly firm sales volumes for the review period. Public Staff witness Perry testified that, as of June 30, 2013, Toccoa's NC Deferred Account had a credit balance of $14,379 owed by Toccoa to customers, compared to the previous review period ending debit balance of $121,623, owed by customers to Toccoa. She also testified that the $136,002 increase in Toccoa's NC Deferred Account consisted of the following Deferred Account activity: Commodity True-up of ($3,001), Demand True-up of ($22,053), Firm Hedges of $78,919, Increment activity of ($192,250), and a prior period adjustment of $2,384.

Based on the foregoing, the monthly filings by Toccoa pursuant to Commission Rule R1-17(k)(5)(c), and the findings and conclusions set forth above, the Commission concludes that Toccoa has properly accounted for its gas costs incurred during the review period and that Toccoa's NC Deferred Account balance reflected in the Company's exhibits is correct.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence supporting this finding of fact is contained in the testimony of Toccoa witness Trippe and Public Staff witness Perry.

Company witness Trippe testified that Toccoa participates in the Gas Authority's “WinterHedge” program under the Authority’s Option 2. Witness Trippe stated that the Gas Authority’s objective in hedging prices is to achieve price stability at a reasonable level for its members’ retail customers. He further explained that this is accomplished by locking-in futures prices on approximately 50% of Toccoa’s firm load (based on normal weather) for the months of October through March each winter.

Company witness Trippe also testified that although hedging helps manage volatility in the wholesale cost of gas, it can create its own challenges. Some customers have unrealistic expectations of the benefits of hedging, because a common benchmark for evaluating hedged prices is the actual spot market price. Witness Trippe further testified that this can be an unfair measure because it is only available after the fact, and assumes that the goal of hedging is “to beat the market.” He also testified that the principal goal of hedging is to achieve price stability, at a reasonable level, for the consuming public.

Witness Perry testified that when a Gas Authority member enters into hedging arrangements with the Gas Authority, the member specifies the targeted level of volumes to hedge and that these arrangements typically span two to three years. Witness Perry further testified that the Gas Authority typically uses fixed price swaps, basis swaps, and three-way options as financial instruments in its hedging program.

Witness Perry testified that during the current review period the hedging program resulted in a $78,919 charge to its gas supply cost for North Carolina customers. As discussed in her testimony in a previous annual review of gas costs, witness Perry explained that this charge to gas supply costs is the result of hedging positions that were established during the late fall of 2008 through early 2009 during a period of higher gas prices. Witness Perry further testified that these hedging positions resulted in strike prices between $6.00 and $7.00 per dt, which at the time of sale were measured as historically low by the historical price data. She testified that as prices have subsequently trended below the strike price of these instruments, the result has been hedging losses such as those incurred during the review period.

Public Staff witness Perry testified that, as discussed in a previous annual review of gas costs, another factor that has contributed to the ongoing hedging costs incurred by Toccoa was the Gas Authority’s 2008 decision to extend its hedging horizon to a longer term than it had been previously. She explained that in an attempt to stabilize price volatility on a portion of the members' firm load requirements, the Gas Authority entered into hedge positions for a period of six years. Witness Perry further explained that by extending the hedge horizon, hedge positions placed during the fall 2008 to early 2009 will extend into the year 2014.

Witness Perry provided testimony that prior to the expiration of the current hedge positions in 2014, the Gas Authority’s hedge program will be limited to a 24-month rolling term. She explained that members may elect to participate in the program and their commitments will only extend until the end of the 24-month period in which they elect to enroll. She further explained that at this time Toccoa has not made any decisions about future hedge program participation decisions although discussions between the Gas Authority staff and Toccoa on this subject are in progress.

Public Staff witness Perry further testified that based on what was reasonably known or should have been known by Toccoa at the time the Company made its hedging decisions affecting the review period, as opposed to the outcome of those decisions, her analysis led her to conclude that the hedging decisions were prudent.

Based on the testimony presented by the Company and the Public Staff, the Commission concludes that the Company's hedging activities during the review period were reasonable and prudent.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 9 -14

The evidence for these findings of fact is contained in the testimony of Toccoa witness Trippe and Public Staff witnesses Ross and Perry.

Company witness Trippe testified that Toccoa is a charter member of the Gas Authority, the largest non-profit joint action natural gas agency in the nation. Company witness Trippe also testified that, as a member of the Gas Authority, Toccoa receives all of its gas supply at very competitive rates. He further explained that the Gas Authority uses a portfolio approach to supply its 76 member cities' needs, relying on a combination of long-term firm supply arrangements, short-term spot market purchases, seasonal peaking, and contract storage services. He also testified that Toccoa is assured adequate, dependable, and economical gas supplies through the Gas Authority's efforts.

Public Staff witness Ross testified that Toccoa has eight contracts for pipeline capacity and storage service from Transcontinental Gas Pipe Line Company, LLC; a storage service contract with Pine Needle LNG Company, LLC; and a gas supply contract with the Gas Authority. Witness Ross testified that Toccoa secures its gas supply at monthly index market prices. He further explained that as the all requirements supplier for Toccoa, the Gas Authority manages all of Toccoa's pipeline, storage service, and gas supply contracts. Based upon his investigation and review of the data filed in this docket, witness Ross further testified that Toccoa's gas costs during the review period were prudently incurred.

Company witness Trippe testified that the Gas Authority, on behalf of Toccoa, was able to release a portion of Toccoa's unutilized capacity each month of the review period to mitigate the cost of extra demand capacity, generating a savings during the period of July 2012 - June 2013 that totaled $23,459. Public Staff witness Perry testified that Toccoa's policy has always been to flow through 100% of its capacity release credits to ratepayers.

Public Staff witness Perry testified that the balance in Toccoa's deferred account at June 30, 2013, was a $14,379 credit balance owed to customers. While the Public Staff would typically recommend a rate decrement to refund the credit balance, Public Staff witness Ross recommended using a projected deferred account balance of $45,000 as of March 31, 2014, owed by customers to the Company, which incorporates Toccoa's upcoming estimated winter hedging costs. This amount was estimated based on Toccoa's existing temporary rate being in effect until December 1, 2013.

Public Staff witness Ross explained that in general, a local distribution company's (LDC's) increments or decrements are calculated using the volumes from an LDC's last general rate case. He further stated that as Toccoa has never had a general rate case, the Public Staff has previously recommended, and the Commission has approved, using the NC firm sales volumes for the review period instead. For this review period, the North Carolina firm sales volume is 77,507 dts. Therefore, Public Staff witness Ross proposed that a temporary rate increment of $0.5806/dt be approved for all North Carolina firm customers, effective the first day of the month following the date of the Commission's order in this proceeding, and that it replace the $3.8000/dt temporary rate increment currently in rates. He also testified that this represents a $3.2194/dt decrease from the previous temporary rate increment. As the winter season matures, Toccoa plans to monitor its deferred account balance and will file to adjust its temporary rate increment through the purchased gas adjustment (PGA) process, if warranted.

Public Staff witness Ross testified that the primary reason for recommending an increment is evidenced by the Company's estimated deferred account balance as of March 31, 2014, which the Company has projected will be reversed to a debit balance of approximately $45,000, owed by customers to the Company. Public Staff witness Ross further explained that due to the problems Toccoa has had over the years collecting its high deferred account balances, he believed that it is better to use a more salient estimate of the deferred account balance in order to determine Toccoa's temporary rate element.

Public Staff witness Ross also testified that during the review period representatives from Toccoa and the Public Staff met and developed a strategy to mitigate the high deferred account balances. Based on these discussions, Toccoa made a PGA filing in Docket No. G-41, Sub 36, in which the Commission ordered that the temporary rate increment established in Toccoa's 2012 Annual Review of Gas Costs proceeding, $1.9191/dt, effective December 1, 2012, be increased to $3.8000/dt, effective February 1, 2013. Witness Ross explained that this succeeded in materially reducing Toccoa's deferred account balance. Similarly, Public Staff witness Ross further explained that he did not believe that recommending a temporary rate decrement would be in the best interest of Toccoa at this time when the deferred account balance will be reversed to a debit balance in the near future. He also stated that regarding the effect on customers, an increasing balance owed to the Company leads to correspondingly increased temporary increments in order to be effective in reducing the balance over a shorter time period.

Public Staff witness Ross also testified that using this approach in the instant docket is consistent with that in Docket No. G-40, Sub 110, an annual review of gas costs proceeding for Frontier Natural Gas Company, LLC (Frontier), in which the Commission found that it was not appropriate to require Frontier to implement a decrement at that time. Frontier is comparable to Toccoa in its size and maturity as an LDC.

Public Staff witness Ross further testified that requiring Toccoa to implement a rate decrement at this time would not be productive. He stated that the Company agreed with his recommendation.

Based on the foregoing, the Commission concludes that the Company's gas purchasing policies and practices during the review period were reasonable and prudent, that its gas costs during the review period were prudently incurred, and that the Company should be permitted to recover 100% of it's prudently incurred gas costs. The Commission further concludes that a temporary rate increment is appropriate and should be implemented as recommended by Public Staff witness Ross and agreed to by Toccoa.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The evidence supporting this finding of fact is contained in Toccoa's responses to the Commission's Sub 91 Order and the testimony of Public Staff witness Ross.

Public Staff witness Ross testified that Toccoa had properly responded to the Sub 91 Order.

Based on the foregoing, the Commission concludes that Toccoa has complied with the requirements of the Commission's Sub 91 Order, and submitted responses to the questions set forth in that Order. The Commission appreciates Toccoa's responses.

IT IS, THEREFORE, ORDERED as follows:

1. That Toccoa's accounting for gas costs for the 12-month period ended June 30, 2013, is approved;

2. That the gas costs incurred by Toccoa during the 12-month period ended June 30, 2013, were reasonably and prudently incurred, and that Toccoa is authorized to recover 100% of its gas costs as provided herein;

3. That Toccoa shall remove the existing temporary rate increment that was implemented in Toccoa's filing in Docket No. G-41, Sub 36, effective February 1, 2013, and implement the temporary rate increment proposed by Public Staff witness Ross in the instant docket, effective for service rendered on and after December 1, 2013; and,

4. That Toccoa shall give notice to its customers of the rate changes allowed in this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 26th day of November, 2013.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

NATURAL GAS -- RATE INCREASE

DOCKET NO. G-9, SUB 631

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Piedmont Natural Gas Company, Inc. for a General Increase in its Rates and Charges	) ORDER APPROVING PARTIAL) RATE INCREASE AND ALLOWING) INTEGRITY MANAGEMENT RIDER

HEARD IN: Guilford County Courthouse, High Point, North Carolina, on August 29, 2013; Mecklenburg County Courthouse, Charlotte, North Carolina, on August 29, 2013; New Hanover County Courthouse, Wilmington, North Carolina, on September 5, 2013; and the Commission Hearing Room, Dobbs Building, Raleigh, North Carolina, on October 14 and 17, 2013

BEFORE: Chairman Edward S. Finley, Presiding, and Commissioners Bryan E. Beatty, Susan W. Rabon, ToNola D. Brown-Bland, Jerry C. Dockham, and James G. Patterson

APPEARANCES:

For Piedmont Natural Gas Company, Inc.:

James H. Jeffries IV and Brian S. Heslin, Moore & Van Allen PLLC, Bank of America Corporate Center, 100 North Tryon Street, Suite 4700, Charlotte, North Carolina 28202-4003

For the Using and Consuming Public:

Elizabeth A. Denning, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

Margaret A. Force, Assistant Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602

For Carolina Utility Customers Association, Inc.:

Robert F. Page, Crisp, Page & Currin, LLP, 4010 Barrett Drive, Suite 205, Raleigh, North Carolina 27607

For the Greenville Utilities Commission and the Cities of Rocky Mount and Wilson:

M. Gray Styers, Jr., Styers, Kemerait & Mitchell, 1101 Haynes Street, Suite 101, Raleigh, NC 27604

For the Public Works Commission of the City of Fayetteville:

James P. West, West Law Offices, PC, Suite 2325, Two Hannover Square, 434 Fayetteville Street, Raleigh, NC 27601

BY THE COMMISSION: On April 30, 2013, Piedmont Natural Gas Company, Inc. ("Piedmont" or the "Company"), gave notice pursuant to Commission Rule R1-17(a) of its intent to file a general rate case.

On May 10, 2013, the Carolina Utility Customers Association, Inc. (CUCA), filed a Petition to Intervene. On May 17, 2013, the Commission issued an Order granting the Petition to Intervene of CUCA.

On May 31, 2013, Piedmont filed a petition (Petition) seeking a general increase in and revisions to its rates and charges, implementation of a new Integrity Management Rider mechanism, implementation of new depreciation rates, updates and revisions to the Company's service regulations and tariffs, amortization of various deferred expenses, and proposed additional funding for gas distribution research activities conducted by the Gas Technology Institute (GTI). With its Petition, the Company also filed: (1) the Direct Testimony and Exhibits of Thomas E. Skains, Chairman, President and Chief Executive Officer of Piedmont; Karl W. Newlin, Senior Vice President and Chief Financial Officer of Piedmont; Victor M. Gaglio, Senior Vice President and Chief Utility Operations Officer of Piedmont; David R. Carpenter, Vice President of Planning and Regulatory Affairs of Piedmont; Pia K. Powers, Director of Regulatory Affairs of Piedmont; Kally A. Couzens, Senior Regulatory Affairs Analyst of Piedmont; Dr. Donald A. Murry, Vice President and Economist with C. H. Guernsey & Company; Daniel P. Yardley, Principal, Yardley Associates; and Paul M. Normand, President and Management Consultant, Management Applications Consulting, Inc., and (2) the Form G-1 information required by Commission Rule R1-17(b)(12) (Form G-1).

On May 31, 2013, a Petition to Intervene was filed by the Public Works Commission of the City of Fayetteville, and its Petition to Intervene was subsequently allowed by Commission Order issued June 5, 2013.

By Order Scheduling Investigation and Hearing, Suspending Proposed Rates, Establishing Intervention and Testimony Dates and Discovery Guidelines, and Requiring Public Notice issued June 27, 2013 (June 27, 2013 Order), the Commission declared the Company's application to be a general rate case pursuant to G.S. 62-137 and suspended the proposed rates for a period of up to 270 days from and after July 1, 2013. In that Order, the Commission also set the matter for hearing, required the Company to give notice of the hearing, established discovery guidelines, and established dates for interventions and for the prefiling of direct testimony by interveners and for the prefiling of rebuttal testimony by the Company.

On June 28, 2013, Piedmont filed a revised page 13 of the Direct Testimony of David R. Carpenter and a Revised Item 4 of its Form G-1.

On July 18, 2013, the Commission issued its Order Continuing Evidentiary Hearing in which it continued the hearing of Piedmont's case-in-chief from October 14, 2013 until October 16, 2013.

On August 1, 2013, the Attorney General filed its Notice of Intervention.

Between June 3, 2013 and October 11, 2013, the Commission received various consumer statements of position regarding and generally opposing Piedmont's rate increase proposal.

On August 29, 2013, this matter came on for hearing in High Point as scheduled. One person, Mr. Gary Hopkins of High Point, appeared and entered testimony as a public witness.

Also on August 29, 2013, the hearing was continued in Charlotte as scheduled. Mr. Jeffrey Edge from the Charlotte Chamber of Commerce appeared and entered testimony as a public witness.

On September 5, 2013, the hearing was continued in Wilmington as scheduled. Mr. Scott Satterfield appeared and entered testimony as a public witness.

On September 19, 2013, the Greenville Utilities Commission and the Cities of Rocky Mount and Wilson (collectively the Municipal Intervenors) filed a Petition to Intervene which was allowed by Commission Order dated September 20, 2013.

On September 20, 2013, the Public Staff filed a Motion for Extension of Time in which it sought a one-week extension in the dates for filing intervenor and rebuttal testimony. The Public Staff's motion was granted by Commission Order dated September 23, 2013.

On September 25, 2013, Piedmont filed its affidavits of publication.

On September 30, 2013, the Public Staff filed its Notice of Settlement in this proceeding whereby it gave notice that Piedmont, CUCA and the Public Staff had reached a settlement in principle and requested that the Commission allow the settling parties until October 4, 2013 to file a formal Stipulation of settlement and supporting testimony. The Public Staff further requested that intervenors be allowed until October 4, 2013 to file their direct testimony and until October 8, 2013 to file testimony addressing the settlement.

On October 2, 2013, the Commission issued an Order granting the Public Staff's request for a modified testimony filing schedule.

On October 4, 2013, Piedmont filed a Stipulation and Exhibits by and between Piedmont, the Public Staff, and CUCA (Stipulating Parties) resolving all issues between these parties. On the same date, Piedmont filed the supporting Supplemental Testimony and Exhibits of Karl W. Newlin, Donald A. Murry, and David R. Carpenter.

On October 8, 2013, Piedmont filed its Motion to Continue Hearing for One Day and to Excuse Witnesses (October 8, 2013 Motion) in which it sought (1) to continue the hearing of its case-in-chief from October 16, 2013 until October 17, 2013 in order to avoid a conflict with the Company's Board of Directors meeting, and (2) to excuse Piedmont's outside consultant witnesses Daniel P. Yardley and Paul M. Normand from appearing at the hearing of the case. In this filing, Piedmont also provided its proposed order of appearance of witnesses and cross-examination estimates provided by counsel for intervenors.

On October 10, 2013, the Attorney General filed its list of witnesses and estimates of cross-examination times.

Also on October 10, 2013, the Municipal Intervenors made a filing indicating they had no objection to Piedmont's October 8, 2013 Motion.

On October 11, 2013, the Commission issued its Order Continuing Hearing and Excusing Witnesses in which it granted the relief requested in Piedmont's October 8, 2013 Motion.

On October 14, 2013, the hearing of this matter was continued in the Commission Hearing room for the purpose of receiving public witness testimony. No public witnesses appeared.

On October 15, 2013, Piedmont filed a revised Exhibit E to the Stipulation.

Also on October 15, 2013, Piedmont filed its Notice of Change in Order of Witnesses.

On October 17, 2013, the case-in-chief came on for hearing as scheduled in Raleigh. At the hearing, the Company reported, and the Stipulating Parties confirmed, that following substantial negotiations, a comprehensive agreement had been reached between the Company, the Public Staff, and CUCA, and that this agreement resolved all issues in the case as between those parties, and that this agreement was reflected in the Stipulation.

At the hearing, the various prefiled Direct and Supplemental Testimony and Exhibits of the following witnesses were offered and accepted into evidence by the Commission: Thomas E. Skains, Karl W. Newlin, Victor M. Gaglio, David R. Carpenter, Pia K. Powers, Kally A. Couzens, Dr. Donald A. Murry, Daniel P. Yardley, and Paul M. Normand. Company witnesses Newlin, Murry and Carpenter testified at the hearing.

Based upon the verified Petition, the 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. Piedmont is a corporation organized and existing under the laws of the state of North Carolina, duly authorized to do business in and engaged in the business of transporting, distributing, and selling natural gas within the states of North Carolina, South Carolina, and Tennessee.

2. Piedmont is a public utility within the meaning of G.S. 62-3(23).

3. The Commission has jurisdiction over, among other things, the rates and charges, rate schedules, classifications, and practices of Piedmont in its capacity as a public utility.

4. In the Petition in this docket, the Applicants are seeking approval of: (a) a general increase in and revisions to the rates and charges for customers served by the Company; (b) certain changes to the cost allocation, rate designs, and practices underlying existing rates for the Company; (c) changes to the Company's existing service regulations and tariffs; (d) implementation of a new Integrity Management Rider mechanism; (e) implementation of new depreciation rates; (f) amortization of certain deferred expenses; and (g) proposed additional funding of gas distribution research and development activities conducted by GTI.

5. The Applicant is properly before the Commission with respect to the relief sought in the Petition in this proceeding pursuant to the provisions of Chapter 62 of the General Statutes.

<u>Test Period</u>

6. The only parties submitting evidence in this case with respect to revenue, expenses, and rate base levels used a test period of the 12 months ended February 28, 2013, adjusted for certain known and measurable changes through September 30, 2013, or thereafter, and the Stipulation was based upon the same test period.

7. The appropriate test period for use in this proceeding is the 12 months ended February 28, 2013, updated for certain known and measurable changes through September 30, 2013, or thereafter.

<u>Stipulation</u>

8. The Stipulation executed by Piedmont, the Public Staff, and CUCA is actively supported or not opposed by all parties to this docket.

9. The Stipulation settles all matters in this docket as between Piedmont, the Public Staff, and CUCA.

<u>Revenue Increase</u>

10. The Petition seeks an increase in annual revenues for the Company of $79,826,196.

11. The Stipulation provides for an increase in annual revenues for the Company of $30,658,314.

12. The stipulated revenue increase of $30,658,314 is just, reasonable and appropriate for use in this proceeding.

<u>Rate Base</u>

13. Based on the expert witness evidence, the public witness evidence, and the Stipulation, the Commission finds that the original cost of the Company's used and useful property, or to be used and useful within a reasonable time after the test period, in providing

natural gas utility service to the public within North Carolina, including gas plant of $3,171,029,577 and working capital of $157,222,039, less that portion of the original cost which has been consumed by depreciation expense of $1,032,491,554 and accumulated deferred income taxes of $473,326,437, all as described and set forth in Paragraphs 5 and 16, and Exhibit A of the Stipulation and reflected on Schedule 1 hereto, are reasonable and appropriate for use in this docket.

Revenues and Operating Expenses

14. Based on the expert witness evidence, the public witness evidence, and the Stipulation, the Commission finds that the Company's end-of-period *pro forma* revenues under present rates of $860,537,121, as set forth in Paragraph 6 and Exhibit A of the Stipulation and reflected on Schedule 1 hereto, are reasonable and appropriate for use in this docket.

15. Based on the expert witness evidence, the public witness evidence, and the Stipulation, the Commission finds that the Company's operating expenses of $322,043,707, including actual investment currently consumed through reasonable actual depreciation, as set forth in Paragraph 6 and Exhibit A of the Stipulation and reflected on Schedule 1 hereto, and including the adjustments reflected in Paragraphs 12 through 21 of the Stipulation, are reasonable and appropriate for use in this docket.

Capital Structure

16. Based on the expert witness evidence, the public witness evidence, and the Stipulation, the Commission finds that the capital structure set forth in Paragraph 6 and Exhibit B of the Stipulation, consisting of 50.66% common equity, 46.52% long-term debt at a cost of 5.23%, and 2.82% short-term debt at a cost of 0.53%, is reasonable and appropriate for use in this docket.

Return

17. Based on the expert witness evidence, the public witness evidence, and the Stipulation, the Commission finds that the overall rate of return that the Company should be allowed the opportunity to earn on the cost of the Company's used and useful property is 7.51%, as set forth in Paragraph 6 and Exhibit A of the Stipulation and reflected on Schedule 1 hereto, and is reasonable and appropriate for use in this docket. This also is the rate to be used by the Company as its Allowance for Funds Used During Construction (AFUDC) rate effective January 1, 2014.

18. Based on the expert witness evidence, the public witness evidence, and the Stipulation, the Commission finds that the rate of return on common equity that the Company should be allowed the opportunity to earn in this docket is 10.0%, as set forth in Paragraph 6 and Exhibit B of the Stipulation, and is reasonable and appropriate for use in this docket.

19. The authorized levels of overall return and 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 neither unfair to nor will cause material hardship to the Company's customers in light of changing economic conditions or otherwise.

20. 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. The overall rate of return on rate base and allowed rate of return on common equity underlying Piedmont's current base rates are 8.55% and 10.6% respectively.

b. Piedmont's current base rates became effective on November 1, 2008 and have been in effect since that date.

c. In its Petition, Piedmont sought approval for rates which were based on an overall rate of return on rate base of 8.15% and an allowed rate of return on common equity of 11.3%.

d. In the Stipulation, the Stipulating Parties seek approval of an overall rate of return on rate base of 7.51% and an allowed rate of return on common equity of 10.0%.

e. The reduction in overall return from Piedmont's existing base rates that is reflected in the Stipulation is a substantial economic benefit to Piedmont's customers.

f. Piedmont's currently authorized allowed rate of return on common equity in South Carolina and Tennessee are 11.3% and 10.2% respectively.

g. The currently authorized allowed rate of return on common equity underlying Public Service Company of North Carolina, Inc.'s base rates is 10.6%.[1]

h. The currently authorized allowed rate of return on common equity for Duke Energy, Progress Energy, and Dominion Power is 10.2%.[2]

i. The average allowed rate of return on common equity for southeastern United States natural gas local distribution companies granted by various state public service commissions is 10.23%.

j. The estimated 2013 rate of return on common equity projected by Value Line for natural gas companies comparable to Piedmont is 10.2%.

k. The Value Line 2013 projected rate of return on common equity for Piedmont is 11.0%.

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[1] Order Approving Partial Rate Increase and Requiring Conservation Program Filing and Reporting, Docket No. G-5, Sub 495 (October 24, 2008).

[2] Order Granting General Rate Increase, Docket No. E-7, Sub 1026 (September 24, 2013); Order Granting General Rate Increase, Docket No. E-2, Sub 1023 (May 30, 2013); and Order Granting General Rate Increase, Docket No. E-22, Sub 497 (December 12, 2012).

l. The stipulated allowed rate of return on common equity of 10.0% is lower than any of the comparable allowed rates of return on common equity identified in above.

m. The stipulated overall rate of return on rate base of 7.51% and allowed rate of return on common equity of 10.0% are supported by competent, material, and substantial evidence.

n. There is no competent, material and substantial evidence that the stipulated overall rate of return on rate base of 7.51% or allowed rate of return on common equity of 10.0% will be harmful, injurious, or unfair to customers.

o. There is no competent, material, and substantial evidence supporting any overall rate of return on rate base or allowed rate of return on common equity other than the stipulated overall rate of return on rate base of 7.51% and allowed rate of return on common equity of 10.0%.

p. The stipulated rates will produce average annual residential bills for Piedmont's customers [at the Company's existing Benchmark Commodity Cost of Gas (Benchmark) of $740.

q. An annual average residential bill of $740 is substantially lower than the annual residential bill resulting from Piedmont's last general rate case in 2008 and is lower than actual average annual residential bills paid by Piedmont's customers in eight of the last nine years.

r. The impact of the stipulated rate increase on the average residential customer, exclusive of other rate adjustments that will occur on or shortly before the effective date of rates herein, is $30 a year or $2.50 a month. Approximately 45% of this increase is for an increase in fixed gas costs which Piedmont is statutorily entitled to recover.[1]

s. A recent adjustment to Piedmont's Margin Decoupling Tracker (MDT) mechanism rate increment and a prospective adjustment in Piedmont's fixed gas costs, as well as a potential adjustment in Piedmont's Benchmark, will more than offset, by as much as $50 a year for an average residential customer, the impact of the stipulated rate increase.

t. Unchallenged evidence presented at the hearing of this matter indicates that the overall economic climate in North Carolina (and nationally) is improving, including data and projections from reliable sources that in the few months before the hearing in this matter: (i) initial jobless claims were declining; (ii) consumer confidence was improving; (iii) projected job growth was improving; (iv) real disposable income was increasing; (v) private wages and salaries were increasing; (vi) personal savings as a percentage of disposable income were increasing; (vii) personal spending for consumption was increasing; (viii) the rate of late payments on credit card debt was improving; (ix) North Carolina exports were materially increasing; (x) construction starts were improving; (xi) business investing was improving; (xii) multiple additional businesses announced plans to either move to North Carolina or to

[1] N.C. Gen. Stat. 62-133.4.

expand jobs in the State; (xiii) housing prices increased; and (xiv) the North Carolina economy was expected to generate 86,000 new jobs in 2014.

u. The characteristics of North Carolina households are similar to the United States as a whole with some minor distinctions.

v. Piedmont is engaging in a very significant capital construction program during the next 3 years, much of which relates to the Company's integrity management programs in compliance with federal regulations to enhance the safety and integrity of its natural gas transmission facilities.

w. Access to capital at reasonable rates is critical to Piedmont's ability to fund its capital construction program.

x. Establishing an allowed rate of return on common equity at a rate below 10.0% could pose a threat to Piedmont's ability to access both debt and equity capital on reasonable terms.

y. The 10.0% return on equity and the 50.66% equity financing approved by the Commission in this case results in a cost of capital that, within the context of the Stipulation, will enable Piedmont by sound management to produce a fair return for its shareholders, considering changing economic conditions, and is reasonable and fair to Piedmont's customers. It appropriately balances Piedmont's need to obtain equity financing and maintain a strong credit rating with its customers' need to pay the lowest possible rates.

<u>Throughput</u>

21. For the purpose of this proceeding, the appropriate level of adjusted sales and transportation volumes is 128,818,548 dekatherms (dts), which is comprised of 66,294,712 dts of sales quantities and 62,523,836 dts of transportation quantities. The total throughput, including electric generation and special contract quantities, is 289,955,054 dts. The appropriate level for company use and lost and unaccounted for gas is 2,447,552 dts, and the appropriate level of purchased gas supply is 68,742,264 dts consisting of sales volumes, company use and lost and unaccounted for gas.

<u>Cost of Gas</u>

22. The total cost of gas reasonable and appropriate for use in this proceeding is $418,904,994, as described in Paragraph 4 and on Exhibit I to the Stipulation and consisting of $299,642,527 in commodity costs, $11,013,986 in company use and lost and unaccounted for costs, and $108,248,481 in fixed gas costs.

23. The Benchmark reasonable and appropriate for use in this proceeding is the Company's current Benchmark of $4.50/dt, subject to any filed changes in such rate prior to implementation of revised rates in accordance with this order.

24. The fixed gas costs that should be embedded in the proposed rates and used in true-ups of fixed gas costs for periods subsequent to January 1, 2014, in proceedings under Commission Rule R1-17(k), subject to any filed changes in such costs prior to January 1, 2014, are those derived from the fixed gas cost allocation percentages discussed in Paragraph 8 and set forth in Exhibit D to the Stipulation.

Rate Design

25. The rate design and rates, including volumetric rates, fixed monthly charges, demand charges, and other charges, as described in Paragraph 7 of the Stipulation and reflected in the column shown as ”Proposed Rates ($/DT)” on Exhibit C of the Stipulation (as the same may be adjusted for any changes in the Company’s Benchmark or changes in Demand and Storage Charges prior to the effective date of the revised rates), comprised, in part, of the rate elements set forth on Exhibit K to the Stipulation, are just and reasonable and appropriate for use in this docket. Similarly, the percentage increases by customer class that result from the rates design aforementioned and shown on Exhibit J are also just and reasonable.

Integrity Management Rider

26. The Integrity Management Rider (IMR) attached to the Stipulation as Exhibit F is reasonable and appropriate and consistent with G.S. 62-133.7A, and should be approved and implemented as provided in Paragraph 9 of the Stipulation.

Margin Decoupling Factors

27. The “R” values and heat factors set forth on Exhibit E to the Stipulation and reflected in Paragraph 10 of the Stipulation are reasonable and appropriate for use with the Company’s Margin Decoupling Tracker mechanism and should be approved.

Amortization of Deferred Assets

28. The quantification and amortization of certain deferred assets, including Pipeline Integrity Management (PIM) operating and maintenance (O&M) costs, EasternNC O&M costs, environmental assessment and clean-up O&M costs, Robeson Liquefied Natural Gas (LNG) development costs, and NCNG OPEB (Other Post- Employment Benefits) costs, all as set forth and described in Paragraph 11 of the Stipulation, is reasonable and appropriate and should be approved.

Implementation of State Tax Changes

29. The proposed process for modification of Piedmont’s rates to make appropriate adjustments to Piedmont’s rates for the effect of pending reductions in North Carolina corporate income tax rates reflected in North Carolina Session Law 2013-316 (House Bill 998), and as set forth in Paragraph 22 of the Stipulation, is reasonable and appropriate and should be approved.

Depreciation Rates

30. The change in depreciation rates for the Company agreed to in the Stipulation and previously filed in Docket No. G-9, Sub 77G is reasonable and appropriate and should be approved effective January 1, 2014.

Changes to Rate Schedules and Service Regulations

31. The changes to the Company's Rate Schedules and Service Regulations reflected in Exhibits G and H to the Stipulation, and the margin loss mitigation plan as described in Paragraph 30 of the Stipulation, are reasonable and appropriate and should be approved.

Gas Technology Institute Research Funding

32. The proposed additional funding of GTI research and development activities of $340,000 per year, as discussed in Paragraph 25 of the Stipulation, is reasonable and appropriate and should be approved.

Miscellaneous Matters

33. The various agreements between the Company, the Public Staff and CUCA, reflected in paragraphs 4.C., 26, 27, 28, and 31 of the Stipulation as to accounting conventions and practices relative to (i) the Company's gas cost deferred accounts, (ii) the filing of tariff revisions related to vehicular natural gas service, (iii) a possible filing for a change in the Company's Benchmark Commodity Cost of Gas, and (iv) the implementation schedule for the Public Staff to conduct the investigation of Piedmont required pursuant to Docket No. M-100, Sub 113A, are each reasonable and appropriate and should be approved.

34. All of the provisions of the Stipulation are just and reasonable to all parties to this proceeding, serve the public interest, and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1 - 5

The evidence supporting these findings is contained in the Company's verified Petition, the testimony and exhibits of the Company's witnesses, the Form G-1 that was filed with the Petition. These findings are essentially jurisdictional and procedural in nature and are based on uncontested evidence.

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

The evidence supporting these findings is contained in the Petition, the Direct Testimony of Piedmont witness Powers and the Stipulation.

In its Petition, the Company utilized a test period of the 12 months ended February 28, 2013 in presenting its application and exhibits for the requested rate increase. This test period was confirmed in the Direct Testimony of Piedmont witness Powers who indicated that, consistent with North Carolina statutory requirements and the Commission's Rules, the

Company had based its Petition on the 12 month period ended February 28, 2013. In its June 27, 2013 Order, the Commission ordered the parties to use a test period consisting of the 12 months ended February 28, 2013, with appropriate adjustments. The Stipulation is based upon the test period ordered by the Commission, with appropriate adjustments in some cases, and this test period was not contested by any party. In the Stipulation, the Stipulating Parties agreed to make appropriate adjustments to the test period data for circumstances occurring or becoming known through February 28, 2013, or thereafter. No party introduced evidence supporting an alternative test period or opposing the use of the 12 months ended February 28, 2013, with appropriate adjustments, as the appropriate test period in this case.

Based upon the unopposed evidence, the Commission concludes that the 12 months ended February 28, 2013, with appropriate adjustments, is the appropriate test period for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 8 - 9

The evidence supporting these findings consists of the Stipulation, the Supplemental Testimony of Company witness Carpenter, and the representations of the parties to the Commission regarding the Stipulation.

In his Supplemental Testimony, Company witness Carpenter describes an extensive audit and negotiation process between the Company, the Public Staff, and CUCA with respect to the Company's filed case, which ultimately led to the willingness of the Company, the Public Staff and CUCA to join the Stipulation. According to Piedmont witness Carpenter, as part of this process, the Company responded to approximately 350 questions from the Public Staff in 28 separate sets of data requests and participated in a multi-day onsite audit of the Company's filing. The Company also responded to multiple data requests from CUCA and the Attorney General, copies of which were provided to each of the Stipulating Parties at the time they were provided to the party initiating such data requests. Following this process, according to Mr. Carpenter, the Company, the Public Staff and CUCA engaged in difficult settlement negotiations for roughly a week before a settlement in principle was reached. The Stipulation was filed on October 4, 2013, and states that it is filed on behalf of Piedmont, the Public Staff, and CUCA and resolves all issues between those parties in the case.

On October 10, 2013, counsel for the Municipal Intervenors made a filing with the Commission in which he indicated that "the Municipal Intervenors do not object to the terms and provisions set forth in the Stipulation filed by Piedmont in this docket on October 4, 2013."

No party filed a formal statement or testimony indicating opposition to the Stipulation, however, the Attorney General did pursue cross-examination of Company witness Dr. Murry at the hearing of this matter on issues related to the appropriate rate of return on common equity for use in this proceeding.

The Stipulation is binding as between Piedmont, the Public Staff and CUCA, and conditionally resolves all matters in this case as between those three parties. The Municipal Intervenors have indicated that they do not oppose the Stipulation and the Fayetteville Power

Commission has not taken a position before the Commission with respect to the Stipulation. Through the end of the evidentiary process, the Attorney General has neither approved nor overtly disapproved of the settlement reflected in the terms of the Stipulation. These constitute all parties to this proceeding.

Under North Carolina law, a stipulation entered into by less than all parties 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." State ex rel. Utilities Commission v. Carolina Utility Customers Association, Inc., 348 N.C. 452, 466, 500 S.E. 2d 693, 703 (1998). Further, "[t]he Commission may even adopt the recommendations or provisions of the nonunanimous stipulation as long as the Commission sets forth its reasoning and makes 'its own independent conclusion' supported by substantial evidence on the record that the proposal is just and reasonable to all parties in light of all the evidence presented." Id.

The Commission concludes based upon all the evidence presented that the Stipulation was entered into by the stipulating parties after full discovery and extensive negotiations and represents a proposed negotiated resolution of the matters in dispute in this docket that is supported, or not opposed, by all parties except the Attorney General.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 10 - 12

These findings are supported by the Petition, the Direct Testimony and Exhibits of Company witness Powers, the Direct and Supplemental Testimony and Exhibits of Company witness Carpenter, and the Stipulation.

Schedule 7 to Exhibit__(PKP-1), attached to the Direct Testimony of Company witness Powers, indicates that the Company filed for a total revenue increase in this proceeding of $79,826,196, consisting of $66,202,716 in increased margin and $13,623,480 in increased fixed gas costs. Ms. Powers explained the various components of this revenue increase request in her Direct Testimony.

The Stipulation, in Paragraph 6, indicates that pursuant to the agreement of the Stipulating Parties the Company should be allowed to increase its revenues by $30,658,314, consisting of $16,808,751 in increased margin, $13,781,445 in increased fixed gas costs, and $68,118 in increased commodity gas costs. This increase in revenues is further reflected in the Supplemental Testimony of Company witness Carpenter and in his Supplemental Exhibit__(DRC-1) detailing the adjustments to Piedmont's filed case reflected in the Stipulation. In his Supplemental Testimony, Mr. Carpenter described the process through which the reductions in Piedmont's filed-for revenue increase were agreed to and also testified that the revenue and non-revenue matters resolved by the Stipulation, including the adjusted proposed revenue increase, were "very well informed and easily within the range of reason." He also noted that the stipulated revenue increase was only 38% of the requested increase and that the total adjusted revenue increase recommended in the Stipulation represented a cumulative increase in revenues of only 3.58% since the effective date of rates in Piedmont's last general rate proceeding in 2008. Spread over the five-year period since Piedmont's last rate case, the rate increase proposed for approval in the Stipulation is well below the overall inflation rate for the same period. Mr. Carpenter further testified that the stipulated resolution of this case would lead to only a small increase in average residential customer rates of roughly $30 per year (or $2.50 a month) which would be more than offset by pending decreases to various components of Piedmont's rates including its MDT increment, its Benchmark and its fixed gas costs. Mr. Carpenter also noted that roughly 45% of the stipulated revenue increase was attributable to an increase in fixed gas costs, which are a flow-through item of expense that does not benefit Piedmont. Mr. Carpenter further testified that the resulting net decrease in customer rates at the time the stipulated revenue increase would go into effect was fair, just and reasonable to all of Piedmont's customers. Mr. Carpenter's testimony has not been challenged by any party and no party has submitted other evidence on this issue.

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, including the discussion and analysis related to the proper rate of overall return and return on common equity for use in this proceeding, the Commission finds, in the exercise of its independent judgment, that the stipulated revenue increase in this case is just, reasonable, and appropriate for ratepayers, the Company, and its shareholders.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence supporting this finding is contained in Schedule 7 of Exhibit__(PKP-1) to the Direct Testimony of Company witness Powers, the Stipulation and the Supplemental Testimony of Company witness Carpenter.

In its initial filing, as reflected in Schedule 7 to Exhibit__(PKP-1), Piedmont proposed the use of original cost rate base of $3,246,683,144, accumulated depreciation of $1,041,287,233, working capital of $179,902,052, and Accumulated Deferred Income Taxes (ADIT) of $473,326,437. In Paragraph 5 and Exhibit A of the Stipulation, the Stipulating Parties agreed that the reasonable original cost of the Company's property used and useful, or to be used and useful within a reasonable time after the test period, in providing natural gas utility service to the public within North Carolina was $3,171,029,577, and that the portion of that cost that had been consumed by depreciation expense was $1,032,491,554. The Stipulating Parties further agreed that an appropriate allowance for working capital was $157,022,359, including the adjustments described in Paragraph 16 of the Stipulation, and that ADIT amounted to $473,326,437. No other party presented evidence on these matters.

The amounts shown on Exhibit A to the Stipulation are the result of negotiated adjustments to the Company's filed position and were agreed to by the Stipulating Parties in this docket, as described in the Stipulation and the Supplemental Testimony of Company witness Carpenter, and are not opposed by any party. The stipulated amounts attributable to the reasonable original cost of the Company's property used and useful, or to be used and useful within a reasonable time after the test period, in providing natural gas service to the public plus an allowance for working capital and less depreciation expense and Accumulated Deferred Income Taxes, is not contested by any party.

The Commission has carefully reviewed these amounts, as well as all record evidence relating to the Company's rate base, which collectively constitute the only evidence in this docket regarding the Company's rate base and concludes that the stipulated amounts are appropriate for use in this docket.

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

The evidence supporting these findings is set forth in the Stipulation and the Supplemental Testimony of Company witnesses Newlin, Carpenter, and Dr. Murry.

The end of test period pro forma revenues under the Company's present and stipulated proposed rates are set forth in Paragraph 6 and Exhibit A to the Stipulation and reflected on Schedule 1 hereto. The amounts shown on Exhibit A to the Stipulation are the result of negotiations among the Stipulating Parties in this docket following an extensive audit of the Company's filed case by the Public Staff and are described in the Stipulation and the Supplemental Testimony of Company witness Carpenter. The Stipulated pro forma revenues represent a reduction of almost $50 million dollars from the revenues proposed by Piedmont in its Petition. No other party submitted evidence on the Company's pro forma revenues, and the stipulated pro forma revenues are not challenged by any party.

The Commission has carefully reviewed these amounts, as well as all record evidence relating to pro forma revenues, and concludes based on its own independent judgment that the stipulated *pro forma* revenues are reasonable and appropriate for use in this docket.

The Company's reasonable operating expenses, including actual investment currently consumed through reasonable actual depreciation, is set forth in Paragraph 6 and Exhibit A to the Stipulation and reflected on Schedule 1 hereto. This amount includes individual adjustments described in Paragraphs 12 through 21 of the Stipulation and in the Supplemental Testimony of Company witness Carpenter. These adjustments, as described by the Stipulation or Mr. Carpenter, include: (i) an allocation of $687,000 in executive compensation to non-utility operations and equity investments; (ii) a downward adjustment of $1,567,890 in the Company's payroll and benefits expense to reflect an annualized going-level expense at August 31, 2013; (iii) a downward adjustment to corporate office overhead allocated to North Carolina of $1,898,493; (iv) a downward adjustment to property taxes of $2,972,072 reflecting the resolution of a property tax dispute between the Company and the North Carolina Department of Revenue that was pending at the time Piedmont's Petition was filed; (v) a downward adjustment of $1,749,394 in the Company's Operations and Maintenance (O&M) expense attributable to an increased allocation of O&M expense to non-utility businesses; (vi) a downward adjustment in pension expense of $2,782,883; (vii) a downward adjustment to non-gas uncollectibles expense of $130,760; (viii) an upward adjustment of $86,434 to regulatory fee expense attributable to the increase in Piedmont's regulatory fee ratio effective July 1, 2013; and (ix) a downward adjustment to Piedmont's annual amortized rate case expense amount of $140,327.

The amounts shown on Exhibit A to the Stipulation, including the adjustments described in Paragraphs 12 through 21 of the Stipulation, are the result of negotiations among the Stipulating Parties in this docket, as described in the Stipulation and the Supplemental Testimony of Company witness Carpenter. No other party submitted evidence as to the Company's reasonable operating expenses and the stipulated reasonable operating expenses of the Company are not contested by any party.

The Commission has carefully reviewed these amounts, as well as all record evidence relating to the Company's reasonable operating expenses, and concludes that the stipulated reasonable operating expenses, including actual investment currently consumed through reasonable actual depreciation and the adjustments reflected in Paragraphs 12 through 21 of the Stipulation, are appropriate for use in this docket.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

The evidence for this finding is contained in the prefiled Direct and Supplemental testimony of Company witness Newlin and the Stipulation.

In the Petition, and as explained by Piedmont witness Newlin in his Direct Testimony, the Company filed its case utilizing a capital structure consisting of its actual equity and long-term debt as of February 28, 2013, updated for known and measurable changes through December 31, 2013. The equity and long-term debt components of the Company's capital structure calculated in this manner were 50.7% common equity and 46.5% long-term debt. For short-term debt, the Company proposed to utilize a 13-month average of its gas inventory as a proxy, consistent with long-standing practice in prior rate case proceedings, which resulted in a short-term debt component of the Company's capital structure of 2.8%. According to Mr. Newlin, for the cost of long-term debt, the Company used 5.18% -- the Company's actual embedded long-term debt cost as of February 28, 2013 -- adjusted for both an anticipated $300 million long-term debt issuance later this year and the elimination of $100 million in currently outstanding long-term debt coming due in December 2013. For short-term debt cost, Mr. Newlin explained that the Company used the actual cost of short-term debt incurred by the Company for the 12 months ended February 28, 2013 of 0.62%.

In the Stipulation, in Paragraph 6, the Stipulating Parties agreed that the capital structure appropriate for use in this proceeding was 50.66% common equity, 46.52% long-term debt, and 2.82% short-term debt. This is essentially identical to the capital structure proposed by the Company in its Petition. For the cost of long-term debt, the Stipulating Parties used 5.23% and for the cost of short-term debt, the Stipulating Parties agreed to use 0.53%.

Mr. Newlin's testimony as to the Company's capital structure was not challenged and no other party submitted testimony on the issue of the appropriate capital structure for the Company.

Based upon the evidence described above and the record in this docket as a whole, the Commission concludes that the stipulated capital structure and costs of long-term and short-term debt are fair and reasonable, and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 17 - 20

The evidence supporting these findings is contained in the Petition, the prefiled Direct and Supplemental Testimony and Exhibits of Company witnesses Newlin and Dr. Murry, the hearing testimony of Company witnesses Carpenter and Dr. Murry, and the Stipulation. No other party submitted evidence on the appropriate overall rate of return on rate base ("ROR" or "Overall Return") or allowed rate of return on common equity appropriate for use in this proceeding.

Based upon the evidence and legal analysis set forth below, the Commission concludes, on the basis of its own independent analysis, that the stipulated allowed rate of return on common equity of 10.0% proposed in the Stipulation in this proceeding and the resulting stipulated overall rate of return on rate base of 7.51%, 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

Piedmont's existing allowed rate of return on common equity, established by the Commission in 2008 in Docket No. G-9, Sub 550, is 10.6%.[1] Its existing approved overall rate of return on rate base is 8.55%. In its Petition, Piedmont proposed that the allowed rate of return on common equity in this proceeding be established at 11.3%. 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 8.15%.

Piedmont's original return on common equity request was supported by the Direct Testimony and Exhibits of Piedmont witnesses Newlin and Dr. Murry. Dr. Murry, a Professor Emeritus of Economics at the University of Oklahoma and a Vice President of the economic consulting firm C.H. Guernsey & Company, served as Piedmont's cost of capital witness and provided the econometric analysis underlying Piedmont's return on common equity request of 11.3%. Dr. Murry's Direct Testimony and Exhibit documents the specific econometric analyses he conducted in support of Piedmont's rate filing and provides a detailed description of the results of his analyses and resulting cost of capital recommendations. According to Dr. Murry, his analyses started with accepting the Company's proposed capital structure of 50.7% common equity, 46.5% long-term debt, and 2.8% short term debt with long- and short-term debt costs of 5.18% and 0.62% respectively. Dr. Murry then studied the current and near-term credit and equities markets, the associated current financial statistics, current and forecasted gas distribution utility common stock earnings, and market-based measures of return on common stock. Like most cost of capital witnesses, Dr. Murry conducted a discounted cash-flow (DCF) analysis of Piedmont and a group of 8 comparable companies and also conducted a Capital Asset Pricing Model (CAPM) analysis, both of which were designed to provide a quantitative basis for his ultimate determination of Piedmont's cost of capital.

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[1] See Order Approving Partial Rate Increase and Requiring Conservation Program Filing and Reporting, Docket No. G-9, Sub 550 (October 24, 2008).

According to Dr. Murry, the results of his DCF analysis were a 9.14% cost of common equity for Piedmont and a comparable company average cost of common equity of 10.56% (with a range of 8.0% to 13.76%). Dr. Murry cautioned that these mathematical DCF results were low in his opinion due to the marginal cost nature of the DCF methodology and also indicated that the results required interpretation due to the impact of the then current volatility in the equities markets (and the impact of that volatility on the factors utilized to conduct his DCF analysis). The results of Dr. Murry's CAPM analysis showed a cost of common equity for Piedmont of 11.8% and a comparable company average of 12.13%. Dr. Murry also indicated that the *Value Line* estimated return on common equity for Piedmont for 2013 was 11.0% and that it projected that this rate of return on common equity would remain consistent into at least 2016. The estimated Value Line average return on equity for Dr. Murry's comparable companies is 10.2%.

Based on his interpretation of these analyses, the state of the markets, investor expectations, and other econometric factors and analyses, Dr. Murry indicated his opinion that the proper cost of capital for Piedmont was between 11.0% to 11.5% and that his recommendation was 11.3%. Dr. Murry then confirmed the reasonableness of his recommended cost of capital using an after-tax interest coverage (ATIC) analysis. Dr. Murry also clarified that this recommended allowed rate of return on common equity for Piedmont would result in an overall return on rate base of 8.15%.

Piedmont's Senior Vice President and Chief Financial Officer, Karl Newlin, in his Direct Testimony supported all the elements of Piedmont's proposed capital structure other than the cost of common equity. Mr. Newlin also provided the Commission with an overview of the unsettled state of the capital markets in which the Company was competing for debt and equity capital and explained the importance and significance of the Commission's ultimate allowed rate of return on common equity in this proceeding to the Company's ability to compete for and obtain adequate access to debt and equity capital on reasonable terms. Mr. Newlin stressed that obtaining access to such capital was critical for the Company as a result of the significant capital investment budget of the Company related to system pipeline integrity compliance related projects in the next several years. Finally, Mr. Newlin testified that the proposed allowed return on common equity of 11.3% was fair and reasonable to Piedmont's customers in light of current and changing economic conditions. Mr. Newlin's assessment in this regard was based upon a number of factors, including (1) the substantial economic and job benefits that will result from Piedmont's pending capital investments in integrity related projects, (2) the approximate $170 dollar reduction in annual customer bills resulting from Piedmont's filed case in this proceeding when compared to annual customer bills resulting from Piedmont's last rate case, (3) the relatively modest level of annual rate increase sought by Piedmont's filed case in comparison to the inflation rate during the period since Piedmont's last rate case, (4) the significant reduction in Piedmont's overall rate of return in its filed case compared to the overall return approved in its last rate case, and (5) the relatively modest monthly impact on customers of the proposed rate increase.

Following settlement negotiations between Piedmont, the Public Staff, and CUCA, as is reflected in Paragraph 6 of the Stipulation, the Stipulating Parties propose an allowed rate of return on common equity for the Company of 10.0% and a corresponding overall rate of return on rate base of 7.51%. In the Stipulation, these parties agreed that the proposed return on common equity of 10.0%:

> is deemed by each Stipulating Party to be a reasonable rate of return on common equity that will provide the Company with a reasonable opportunity, by sound management, to produce a fair return for its shareholders, considering changing economic conditions and other factors, to maintain its facilities and 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 fair to its customers and to its existing investors.

Stipulation at ¶ 6.D. The Stipulation further provides that "[e]ach of the Stipulating Parties . . . agrees that such agreed rate of return on common equity, together with the agreed capital structure and adjustments to the Company's rate base and operating expenses, results in a revenue requirement that is just and reasonable to the Company's customers in light of changing economic conditions." Id.

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 Supplemental Testimony of Piedmont witnesses Dr. Murry and Newlin and by the hearing testimony of Piedmont witness Carpenter. In his Supplemental Testimony, Dr. Murry updated the results of his cost of capital analysis and indicated that while an allowed rate of return on common equity of 10.0% was 50 basis points below his original cost of capital range for Piedmont of 10.5% to 11.5%, changes in the capital markets had caused a 50 basis point decline in the cost of capital for comparable natural gas distribution utilities since his Direct Testimony was filed. Based on this updated analysis, Dr. Murry indicated that a return on common equity of 10.0% was at the bottom of his updated range but should be adequate under favorable future market conditions. Dr. Murry then performed an ATIC analysis to confirm his opinion. That analysis showed a lower after-tax interest coverage than in his prior analysis but one that was within the range of the ATIC values for his comparable companies. Based on this fact, Dr. Murry concluded that "many Piedmont common stock investors would view the 10 percent return on common equity as low, but adequate, for Piedmont."

Dr. Murry also noted the context for his analysis of the adequacy of a 10.0% return on common equity for Piedmont and specifically noted that this allowed rate of return on common equity was the result of a negotiated settlement in which many issues were addressed and resolved. He ultimately concluded that the "proposed settlement ROE of 10 percent is adequate, with very little margin for error, for Piedmont at this time."

In support of his conclusions, Dr. Murry also undertook an analysis of contextual factors relative to a return on common equity for Piedmont of 10.0%. In his analysis, Dr. Murry indicated that North Carolina households have similar characteristics to the nation as a whole, that current economic indicators are that the North Carolina economy is improving and growing, and that Piedmont's overall cost of capital (i.e. its overall return on rate base) was decreased significantly in the Stipulation (and that this was a significant benefit to customers).

In his Supplemental Testimony, Company witness Newlin testified that the stipulated rate of return on common equity was at the low end of what could be determined to be reasonable for Piedmont but that it was one component of an overall settlement of the case that each of the Stipulating Parties found to be reasonable. Mr. Newlin then identified a number of factors that he believed indicated that the stipulated return on common equity was, in fact, very reasonable on a contextual basis. First, Mr, Newlin indicated that the stipulated return on common equity was 60 basis points below Piedmont's current allowed return on common equity and 130 basis points below Piedmont's requested return on common equity in this docket. Mr. Newlin also noted that the stipulated return on common equity was 20 basis points lower than Piedmont's allowed rate of return on common equity in Tennessee and 130 basis points below Piedmont's allowed return on common equity in South Carolina. With respect to North Carolina, Mr. Newlin indicated that the stipulated return on common equity was below the current allowed return on common equity for any other major gas or electric utility in North Carolina and that it was also below the average return on common equity approved for natural gas distribution companies in the southeastern United States (10.23%) since 2010. According to Mr. Newlin, all of these facts are indicators of the reasonableness of the stipulated return on common equity.

Mr. Newlin also testified that the average annual residential bill resulting from the Stipulation would be approximately $740 and that this was lower than the average annual residential bill paid by Piedmont customers in eight of the last nine years.

Finally, Mr. Newlin confirmed that the overall rate of return on rate base resulting from the stipulated capital structure and rate of return on common equity was 7.51%, which is well below the 8.55% overall rate of return on rate base underlying Piedmont's current rates.

At the hearing of this matter, Mr. Carpenter testified to several matters relating to the Stipulation and its ultimate impact on customers. First, Mr. Carpenter indicated that the impact of the stipulated rate increase on residential customers would be approximately $30 a year (roughly 45% of which will be for fixed gas cost recovery). Second, Mr. Carpenter indicated that the relatively small rate increase provided for under the settlement would be more than offset by other pending changes to Piedmont's rates. These changes included a pending reduction of $9 million a year in Piedmont's fixed gas costs under an uncontested settlement of a Transcontinental Gas Pipe Line Company, LLC (Transco) rate case awaiting approval at the Federal Energy Regulatory Commission (FERC). The net impact of this change will be a reduction in residential customer bills of approximately $10 a year. Mr. Carpenter also indicated that a reduction in the rates charged to customers under Piedmont's Margin Decoupling Tracker mechanism in Docket No. G-9, Sub 635, effective November 1, 2013, would reduce average residential customers bills by another $40 a year. Finally, a Benchmark change that Piedmont conditionally committed to make in the Stipulation of $0.50/dt would further reduce average annual residential customer bills by approximately $30. The net impact on customers of these three rate changes of approximately $80 and the stipulated increase in rates of approximately $30 is a savings of approximately $50 a year for the average residential customer over existing rates.

No other party presented evidence on the Company's cost of capital or overall rate of return on rate base.

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,[1] 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.

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; . . . The 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 Court succinctly reiterated the Hope and Bluefield standards in its subsequent decision in Permian Basin Area Rate Cases, 390 U.S. 747, 792 (1968), where it held that a regulatory rate of return order should "reasonably be expected to maintain financial integrity, attract necessary capital and fairly compensate investors for the risks they have assumed . . ."

These principles have been found to be consistent with and applicable to public utility return decisions by this Commission, State ex rel. Utilities Comm'n v. General Telephone Co. of the Southeast, 285 N.C. 671, 208 S.E. 2d 681 (1974), and a failure to abide by the minimum standards of Hope and Bluefield, and their progeny, in setting a public utility return on common equity constitutes an unconstitutional taking.

[1] Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944); Bluefield Waterworks & Imp. Co. v. Public Service Comm'n of W. Va., 262 U.S. 679 (1923).

Minimum constitutional requirements aside, G.S. 62-133 provides the legislative framework for Commission decisions on public utility rates. This statute provides a formula for the determination of such rates which includes a determination of the utility's rate base, its operating expenses and return. With respect to the question of return, G.S. 62-133(b)(4) provides that the Commission shall:

> Fix such rate of return on the cost of the property ascertained pursuant to subdivision (1) of this subsection as will enable the public utility by sound management to produce a fair return for its shareholders, considering changing economic conditions and other factors, . . . as they then exist, to maintain its facilities and 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 to its existing investors.

N.C. Gen. Stat. 62-133(b)(4) (2013). It is important to note that G.S. 62-133(b)(4) establishes the statutory criteria for determining an overall rate of return on rate base rather than the narrower determination of a specific rate of return on common equity, which is simply a component part of the overall return allowed to the utility.[1]

In interpreting and applying this statutory directive for the establishment of an adequate, and constitutionally permissible, rate of return for North Carolina public utilities, our Supreme Court has established a number of corollary or clarifying principles.

First, the North Carolina Supreme Court has determined (as noted above) that the enumerated statutory factors are consistent with the requirements of Hope and Bluefield and that these factors comprise "the test of a fair rate of return" under those decisions. State ex rel. Utilities Comm'n v. General Tel. Co., 281 N.C. 318, 370, 189 S.E.2d 705, 738 (1972). This determination establishes that there is no gap between the requirements of the United States Constitution as interpreted by the United States Supreme Court and the requirements of G.S. 62-133(b)(4) with respect to the determination of the appropriate overall return on rate base to be used in establishing utility rates.

Second, the North Carolina Supreme Court has made clear its understanding that the process of determining the appropriate allowed rate of return on common equity in utility rate cases is one that involves the exercise of discretion by the Commission.

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[1] With regard to determining return on common equity, the United States Supreme Court has determined that return on common equity is a cost of providing utility service that is differentiated from other types of costs only by the fact that it is a cost established through the use of subjective judgment by regulators. Missouri ex rel. Southwestern Bell Tel. Co. v. Pub. Serv. Comm'n, 262 U.S. 276 (1923). In Southwestern Bell, Justice Brandeis compared return on common equity to other types of utility costs such as operating expenses, depreciation, and taxes and noted:

> Each is a part of the current cost of supplying the service; and each should be met from current income. When the capital charges are for interest on the floating debt paid at the current rate, this is readily seen. But it is no less true of a legal obligation to pay interest on long-term bonds . . . and it is true also of the economic obligation to pay dividends on stock, preferred or common.

Southwestern Bell, 262 U.S. at 306.

> Under N.C.G.S. § 62-133 the determination of what is a fair rate of return requires the exercise of subjective judgment. Utilities Commission v. Duke Power Co., 305 N.C. at 23, 287 S.E.2d at 799; see Utilities Comm. v. Telephone Co., 298 N.C. 162, 178, 257 S.E.2d 623, 634 (1979); cf. J.C. Bonright, A.L. Danielson & D.R. Kamerschen, Principles of Public Utility Rates 317 (1988) (describing the highly judgmental aspect of determining the cost of equity capital); C.F. Phillips, Jr., The Regulation of Public Utilities 363-64 (noting the difficulty in estimating the cost of equity capital and recognizing that estimates vary significantly).

State ex rel. Utilities Comm'n v. Public Staff, 323 N.C. 481, 490-91, 374 S.E.2d 361, 366 (1988). It has also recognized the corollary principle that there may be a range of permissible rates of return on common equity that meet statutory and constitutional requirements. State ex rel. Utilities Comm'n v. General Tel. Co., 285 N.C. 671,681, 208 S.E.2d 681 (1974).

Third, the North Carolina Supreme Court has determined 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." State ex rel. Utilities Comm'n v. Duke Power Co., 285 N.C. 377, 388, 206 S.E. 2d 269, 276 (1974). See also State ex rel. Utilities Comm'n v. Public Staff, 323 N.C. at 490, 374 S.E.2d at 366.

Fourth, in complying with the foregoing principles, the Commission must effectively use its judgment to balance between two competing factors, the economic conditions facing customers and the utility's need to attract equity financing in order to continue providing safe and reliable service. State ex rel. Utilities Comm'n v. Public Staff, 323 N.C. at 490, 374 S.E.2d at 366.

Finally, the North Carolina Supreme Court has established that:

> Given the legislature's goal of balancing customer and investor interests, the customer-focused purpose of Chapter 62, and this Court's recognition that the Commission must consider all evidence presented by interested parties, which necessarily includes customers, it is apparent that customer interests cannot be measured only indirectly or treated as mere afterthoughts and that Chapter 62's ROE provisions cannot be read in isolation as only protecting public utilities and their shareholders. Instead, it is clear that the Commission must take customer interests into account when making an ROE determination. Therefore, we hold that in retail electric service rate cases 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.

State ex rel. Utilities Comm'n. v. Cooper, ___N.C. ___, 739 S.E. 2d 541, 548

(2013) (emphasis in original).[1] Return on equity, also referred to as the cost of equity capital, is often one of the most contentious issues to be addressed in a rate case, even in a case such as this one in which a settlement stipulation between the utility and the consumer advocate has been reached. In the absence of a settlement agreed to by all parties, the Commission must still exercise its independent judgment and arrive at its own independent conclusion as to all matters at issue, including return on equity. See, e.g., CUCA I, 348 N.C. at 466, 500 S.E.2d at 707. In order to reach an appropriate independent conclusion regarding return on equity, the Commission should evaluate the available evidence, particularly that presented by conflicting expert witnesses. State ex rel. Utils. Comm'n v. Attorney Gen. Roy Cooper, ___ N.C. ___, 739 S.E.2d 541, 546-47 (2013) (Cooper). In this case, the evidence relating to the Company's cost of equity capital was presented by the stipulating parties. No return on equity expert evidence was presented by any other party.

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 proper return on equity for a public utility. Cooper, ___ N.C. ___, 739 S.E.2d at 548. This is a requirement announced by the Supreme Court in its Cooper decision. One additional principle is applicable to the Commission's return analysis in this case and is driven by the nature of the parties final positions through the evidentiary hearing. These positions are a settlement among all active parties to this docket, other than the Attorney General, the terms of which are reflected in the Stipulation filed by the Company, the Public Staff and CUCA. Under established precedent, and as noted previously in this Order, a stipulation entered into by less than all parties "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." State ex rel. Utilities Commission v. Carolina Utility Customers Association, Inc., 348 N.C. 452, 466, 500 S.E. 2d 693, 703 (1998). Further, "[t]he Commission may even adopt the recommendations or provisions of the nonunanimous stipulation as long as the Commission sets forth its reasoning and makes 'its own independent conclusion' supported by substantial evidence on the record that the proposal is just and reasonable to all parties in light of the evidence presented." Id.

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

The only evidence in this proceeding related to the determination of an overall rate of return on rate base or allowed rate of return on common equity is provided in the Stipulation and in the testimony and exhibits of Piedmont's witnesses Mr. Newlin, Mr. Carpenter, and Dr. Murry. Dr. Murry indicated in his Supplemental Testimony that based upon an updated cost of capital analysis of comparable companies at the time of the Stipulation, the reasonable cost of capital range for Piedmont was between 10.0% and 11.0%. Based on that analysis, he concluded

[1] The Cooper decision is, on its face, limited to electric utility rate cases. That being said, there does not appear to be any obvious distinction between an electric public utility and a natural gas public utility in terms of discerning the intent or application of G.S. 62-133, and, therefore, the Commission's analysis in this case includes consideration of the principles set forth in Cooper.

that a stipulated rate of return on common equity of 10.0% was "adequate, with very little margin of error" for purposes of this case. He confirmed this conclusion by conducting an ATIC analysis. And while this range and specific return on common equity was lower than what Dr. Murry testified to in his Direct Testimony, he explained the basis for his adjusted range and his conclusion that 10.0% is an adequate return on common equity for Piedmont in his Supplemental Testimony. Dr. Murry also provided testimony in which he analyzed the stipulated level of return on common equity in the context of economic conditions facing Piedmont's customers. This analysis included a review of a number of economic statistics regarding the condition of the economy in North Carolina which indicated improving economic conditions and a review of the customer benefits of declining debt and equity costs since Piedmont's last general rate case. He also indicated that customers had been benefited during the same period by a decline in wholesale gas costs which resulted in a substantial reduction in average annual bills resulting from the Stipulation compared to average customer bills resulting from Piedmont's last general rate proceeding. Finally, Dr. Murry indicated his belief that because the stipulated return on common equity was at the low end of the constitutionally permissible range for Piedmont, it was responsive to any customer concerns regarding increased rates.

The Attorney General questioned Dr. Murry about several components of his analysis, but did not provide any affirmative evidence that would support a return on common equity lower than the 10.0% proposed in the Stipulation. In fact, when asked about the impact of a possibly lower return on common equity on customers, Dr. Murry indicated that the impact of a 10 basis point reduction (or increase) in return on common equity was only about $0.12 per month. At best, the Attorney General's cross-examination established only that Dr. Murry could have, but did not, use a different short-term growth forecast for his CAPM analysis, reached a different conclusion on the appropriate return on common equity for Piedmont, etc. In each instance, Dr. Murry convincingly explained his reasoning for his calculations. The Commission finds Dr. Murry to be a credible witness in this case and accepts Dr. Murry's adjusted cost of capital range as probative evidence for purposes of establishing a return on common equity for Piedmont in this proceeding. The Commission notes that Dr. Murry's testimony is the only economic rate of return testimony in this case.

In his Supplemental Testimony, Mr. Newlin testified that the stipulated return on common equity was fair to customers because it was below a number of comparable levels of return on common equity applicable to Piedmont, to other natural gas distribution companies in the southeastern United States, and to other large investor-owned public utilities in North Carolina. Mr. Newlin also testified to the importance of the perception of reasonable regulatory treatment by the Commission to market analysts and, by extension, to the debt and equity markets as a whole. He also discussed the fact that while customers may not subjectively like rate increases, such increases are typically indicators of growth which typically puts downward pressure on customer costs over time and which produces many desirable impacts on the economy. As further evidence of the relative reasonableness of the stipulated result in this case, Mr. Newlin also explained that average annual residential bills resulting from the stipulated rate increase ($740 a year) will be lower than actual annual residential customer bills for eight of the last nine years ($756 to $1,034). Mr. Newlin also indicated in his Supplemental Testimony that, subject to certain conditions, Piedmont has committed to reduce its Benchmark on the effective date of rates requested in this case and that this reduction will largely offset the margin increase granted to Piedmont in this case. Finally, Mr. Newlin cited numerous statistics from a variety of sources indicating an improved and improving economy in North Carolina as evidence that the 3.58% rate increase provided for in the Stipulation is fair and reasonable to customers.

As was noted above, Mr. Carpenter's hearing testimony included the discussion of several offsetting rate adjustments, two of which directly relate to matters integrated into the settlement rates, the net effect of which, when applied as an offset to the stipulated rate increase, will be a reduction to annual residential customer bills of as much as $50.

The uncontested evidence presented by the Company in this case, which is the only evidence other than the Stipulation itself, clearly establishes a *prima facie* case supporting the justness and reasonableness of the Stipulation.

Unlike other recent rate cases before the Commission, there is no record evidence in this case establishing meaningful customer opposition to the stipulated overall rate of return on rate base of 7.51% or the stipulated rate of return on common equity of 10.0% or suggesting that the stipulated rates are either unfair or would cause substantial hardship to Piedmont's customers. Only a single public witness appeared and expressed concern over Piedmont's rate increase request at any of the four public hearings held to receive such public testimony. That witness, Mr. Gary Hopkins, appeared at the High Point public hearing and expressed general concern about the size of Piedmont's rate increase request. Mr. Hopkins testimony was clear that he himself would not have difficulty with paying the proposed increase but that he was concerned that some customers, particularly those living on fixed incomes, might have difficulty. Mr. Hopkins suggested that a "graduating increase," phased in over time, "wouldn't be quite so bad." Mr. Hopkins also indicated that he understood the need of public utilities to increase their rates from time to time in order to maintain reliable service and adequate infrastructure. This testimony is the only evidence in the record that in any way challenges or objects to Piedmont's rate increase request.[1] With respect to the testimony of Mr. Hopkins, the Commission would note that it related to the original rate increase request of Piedmont which sought an increase in residential rates in excess of 10%. The Commission appreciates and acknowledges the testimony of Mr. Hopkins, and echoes his concerns about the potential impact of the original rate increase sought by Piedmont on fixed-income customers. The Commission also recognizes, however, that Piedmont's original rate increase request is no longer before the Commission and has, instead, been replaced with the much more modest 3.58% increase reflected in the Stipulation. Piedmont witness Carpenter testified that, spread out over the period since the last rate case, the 3.58% increase is less than the overall rate of inflation. Furthermore, witness Carpenter testified that the impact of the stipulated increase on the residential ratepayer would be more than offset by pending decreases to various fixed gas costs. The Commission therefore concludes that it is not appropriate to phase in the rate increase in this docket.

The only other indications of consumer discontent with Piedmont's proposed rate increase in this case are a number of consumer "statement of position" letters in this proceeding which either questioned or objected to that rate increase request. With respect to these letters, the Commission notes that they do not satisfy the necessary criteria to be considered competent, material, or substantial evidence upon which the Commission would be entitled to rely in

[1] Two other public witnesses, Mr. Jeffry Edge and Mr. Scott Satterfield, appeared at the Charlotte and Wilmington Public Hearings but both of these witnesses testified in support of the Company's request.

reaching a determination in this case. The Commission further notes, however, that based upon the timing of receipt and the contents of these letters it is clear that they relate, like Mr. Hopkins testimony, to Piedmont's original rate increase request rather than the substantially smaller stipulated rate increase. The Commission again notes that the approved rate increase when coupled with the other provisions of the stipulation will result in a decrease to Piedmont's customers' bills.

While the lack of substantive evidence of consumer opposition to Piedmont's stipulated rate increase provides no evidentiary basis upon which the Commission could reject the Stipulation, it does not relieve the Commission of its 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. Further, even though the record evidence does not establish this fact with respect to any specific Piedmont customer, the Commission of its own experience acknowledges and accepts as true the proposition that some percentage of Piedmont's customers, particularly those living on fixed incomes, are economically vulnerable and may struggle to pay Piedmont's existing rates or any increase to those rates granted in this docket. Piedmont's own witnesses, Dr. Murry and Mr. Newlin acknowledge this reality in their testimony. Likewise, the Commission must keep this in mind as it undertakes to balance the interests of customers with the constitutional requirements of establishing adequate rates for Piedmont.

As noted above, the uncontested record evidence in this proceeding establishes a *prima facie* case supporting the legitimacy and reasonableness of the levels of return on rate base and allowed rate of return on common equity reflected in the Stipulation. In light of this fact, the question for the Commission becomes whether the Stipulation represents an appropriate balancing of the interests of customers, the Company, and shareholders, by establishing rates that are as low as may be reasonably consistent with the requirements of due process. As is explained below, the Commission concludes, based upon its own independent judgment, that the Stipulation satisfies the requirements of North Carolina law in this respect.

As an initial matter, it is clear from the testimony of both Mr. Newlin and Dr. Murry that both believe that the stipulated allowed rate of return on common equity of 10.0% is at the bottom of any reasonable range of possible returns and barely adequate to satisfy the requirements of G.S. 62 133(b)(4). Dr. Murry makes this clear in his Supplemental Testimony, stating that the "proposed settlement ROE of 10 percent is adequate, with very little margin for error, for Piedmont at this time." Dr. Murry also indicates that this conclusion is based, in part, on the fact that the stipulated return on common equity was arrived at through a larger settlement of many issues in the rate case. Dr. Murry's testimony similarly evinces the belief that the stipulated levels of return are not only as low as he could support but also beneficial to customers and responsive to customer concerns because they are as low as is constitutionally permissible. He also testified that any concern over increased rates should be effectively mitigated by decreases in the overall cost of capital since Piedmont's last rate proceeding – a reduction of 60 basis points – and by substantially lowered commodity gas costs.

Mr. Newlin, indicated his belief that the stipulated return on common equity is imminently fair to customers largely by noting the fact that it is in all cases lower than: (1) Piedmont's existing approved return on common equity in North Carolina, (2) Piedmont's approved return on equities in South Carolina and Tennessee, (3) the return on common equities recently granted by the Commission to other major North Carolina utilities, and (4) the average return on common equities allowed to other gas distribution utilities in the southeastern United States since 2010. Mr. Newlin supplemented this conclusion with a discussion of the possible negative impacts on the Company's ability to access both debt and equity at reasonable costs if the allowed return on common equity is set too low – i.e. below 10.0%.

Mr. Newlin also noted that Piedmont is embarking on a multi-year program to enhance and upgrade its facilities in compliance with federal pipeline safety and integrity requirements and that, as a result, access to capital at reasonable rates is a critical requirement of the Company. As an indicator of the reasonableness of the stipulated return and rate increase, Mr. Newlin also testified to a number of factors indicating that the stipulated rates are fair and reasonable and not harmful to customers in light of changing economic conditions. Included among these is the fact that annual residential bills resulting from the Stipulation would be lower than actual annual customer bills in 8 of the last 9 years. Mr. Newlin also provided an extensive listing of economic data and analyses both current and projected which indicated substantial and ongoing improvement in the North Carolina economy.

Mr. Carpenter testified that on an annual basis, customers will see a significant reduction in the amounts they have to pay for natural gas service as the cumulative result of the rate case and other related rate changes to be effective on or before the effective date of rates requested in this case.

It is also significant to note that the Direct Testimony of Piedmont witnesses Gaglio, Newlin, and Carpenter establish that Piedmont is actively engaged in a significant capital investment program over the next few years driven by federal pipeline safety and integrity requirements and that access to capital on reasonable terms is critical to Piedmont in order to fund that investment.

No other evidence has been presented to the Commission on these issues.

The Commission has carefully reviewed the evidence presented on return and the resulting rates in this case and finds the following facts of particular significance to its analysis:

1. The rate of return on common equity reflected in the Stipulation is supported by competent, material and substantive evidence presented by Piedmont's witnesses Dr. Murry, Carpenter, and Newlin and by the Stipulation itself.

2. No other party submitted affirmative evidence supporting any alternative return on equity or overall rate of return on rate base.

3. No other party submitted evidence asserting or supporting the notion that the stipulated return on common equity or overall return is excessive.

4. The stipulated return on common equity of 10.0% is lower than:
   a. Piedmont's existing allowed return on common equity of 10.6%.
   b. Piedmont's existing allowed return on common equities in South Carolina (11.3%) and Tennessee (10.2%).

c. The allowed rates of return for all other significant electric and natural gas public utilities in North Carolina.

d. The average return on common equities allowed to other southeastern natural gas distribution company's (cited in Mr. Newlin's Supplemental Testimony) since 2010.

5. The overall rate of return on rate base of 7.51% is 104 basis points below the original rate of return on rate base approved in Piedmont's last general rate case.

6. The revenue increase proposed in the Stipulation represents a 3.58% increase from rates approved in 2008, or an annual increase of approximately 0.7% per year or $30 per residential customer per year.

7. Approximately 45% of the rate increase provided for by the Stipulation is for an increase in Piedmont's fixed gas costs which Piedmont is statutorily entitled to recover and does not benefit Piedmont.

8. There is no evidence in the record of consumer objections to or the potential for consumer harm resulting from the stipulated rates or stipulated rates of return.

9. There is substantial evidence in the record supporting the notion that the economy of North Carolina is slowly but significantly improving and there is no evidence in the record indicating that this is not the case.

10. As a result of decreased commodity costs of gas, annual residential customer bills resulting from approval of the stipulated rates will be lower than the actual average annual residential customer bills paid by Piedmont's customers in 8 of the last 9 years and will be substantially lower than the annual bills resulting from Piedmont's last general rate case.

11. The stipulated rate increase will be more than offset by other contemporaneous downward adjustments in Piedmont's rates included in the Stipulation, including:

a. A potential downward reduction in Piedmont's Benchmark committed to in the Stipulation.

b. A recent downward reduction in rates under Piedmont's Margin Decoupling Tracker mechanism in Docket No. G-9, Sub 635.

c. A downward reduction in fixed gas costs (which constitute 45% of the stipulated rate increase) that will result from an uncontested settlement of Transco's most recent general rate case before the FERC, which is currently pending approval by that agency.

<u>Conclusions on Return</u>

The Commission accepts as undisputed 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 our 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 utilities which we regulate in that process.

After a careful review of all the evidence in this case, and adhering to the requirements of the above cited legal precedent, 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 the Company and its customers, and appropriate for use in this proceeding and should be approved. The rate increase approved herein, as well as the embedded rates of return underlying such rates, are not unfair or unduly harmful to customers considering changing economic conditions, are as low as is constitutionally permissible, and are required in order to allow Piedmont, by sound management, to produce a fair return for its shareholders, maintain its facilities and 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.

In this matter contemporaneous downward adjustments that will more than offset the stipulated rate increase have been taken under consideration by the Commission as they are part of the Stipulation and have been brought before the Commission in such a form. The Commission has considered these contemporaneous adjustments in its review of the Stipulation. As noted above, pursuant to the Supreme Court's Cooper decision, the Commission must make findings of fact regarding the impact of changing economic conditions on customers when determining the proper return on equity for a public utility. Cooper, ___ N.C. ___, 739 S.E. 2d at 548. Contemporaneous downward adjustments are certainly a type of changing economic conditions that must be considered when determining the impact of a rate increase on residential customers. However, the Commission notes that it does not consider contemporaneous downward adjustments as a necessary factor to grant a rate increase, a request to increase rates should be approved or disapproved based on whether the request itself meets the statutory requirements for approval. Thus, the decision to approve the Stipulation and the rate increase therein is made primarily on the weight of the evidence discussed above.

The Stipulation also states that the overall rate of return on rate base of 7.51% should be used by the Company as its AFUDC rate effective January 1, 2014. The Commission believes that the AFUDC method that has been historically used by the Company is reasonable and appropriate for use in this docket. Therefore, the Commission concludes that it is appropriate for Piedmont to continue to use the approved overall rate of return as its AFUDC rate.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 21

The evidence supporting this finding is contained in the Stipulation and the Supplemental Testimony of Company Witness Carpenter.

Paragraph 3 of the Stipulation sets forth the agreed throughput volumes established by the Stipulating Parties. The level of adjusted sales and transportation volumes used in the Stipulation is 128,818,548 dts and the level of purchased gas supply is 68,742,264 dts. Total throughput, including electric generation and special contract quantities, is 289,955,054 dts. The sales and transportation throughput volume level is derived as follows:

Sales	66,294,712
Transportation	62,523,836
Total Throughput	128,818,548

The level of purchased gas supply is 68,742,264 dts is derived as follows:

Sales	66,294,712
Company Use and Lost & Unaccounted For	2,447,552
Purchased Gas Supply	68,742,264

This throughput level and level of purchased gas supply are the result of negotiations among the Stipulating Parties, as described in the Stipulation and the Supplemental Testimony of Company witness Carpenter, and are not opposed by any party. No other party submitted evidence on the Company's throughput.

The Commission has carefully reviewed the evidence regarding the appropriate throughput level in this docket and concludes that the stipulated throughput levels are a fair and reasonable approximation of the Company's *pro forma* adjusted sales and transportation volumes. The Commission has also carefully reviewed the purchased gas supply level and concludes that it is a fair and reasonable approximation of the Company's *pro forma* purchased gas supply level.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 22 - 24

The evidence for these findings is contained in the Company's initial filing, the Stipulation and in the Supplemental Testimony of Company witness Carpenter.

The test period cost of gas is set forth in Paragraph 4 and Exhibit I to the Stipulation. The amounts shown on Exhibit I to the Stipulation are the result of negotiations among the Stipulating Parties in this docket. The Stipulation reflects the following agreements among the parties regarding Piedmont's cost of gas:

Commodity Costs	$299,642,527
Company Use and Lost & Unaccounted For	$11,013,986
Fixed Costs	$108,248,481
Total Cost of Gas	$418,904,994

The stipulated cost of gas is not contested by any party to this proceeding. The Commission has carefully reviewed these amounts, as well as all record evidence relating to the *pro forma* cost of gas, and concludes that the stipulated cost of gas is reasonable and appropriate for use in this docket.

Under the Commission’s procedures for truing-up fixed gas costs in proceedings under Commission Rule R1-17(k), it is necessary and appropriate to determine the amount of fixed gas costs that are embedded in the rates approved herein. In the Stipulation, the Stipulating Parties agree that for the purpose of this proceeding and future proceedings under Rule R1-17(k) during the effective period of rates approved in this proceeding, the appropriate amount of fixed gas costs to be allocated to each rate schedule is as set forth in Exhibit D to the Stipulation. No party contests this allocation and no other party submitted evidence supporting a different allocation.

The Commission has carefully examined these amounts, as well as all record evidence on fixed gas cost allocations, and concludes that the stipulated allocations of fixed gas costs are fair and reasonable.

Under the Commission’s procedures for establishing rates and truing-up commodity gas costs, it is necessary to establish a Benchmark embedded in sales customer rates. The Stipulation provides that in establishing rates for this proceeding, the parties have agreed to use Piedmont’s current Benchmark of $4.50/dt subject to Piedmont’s conditional commitment to file for a reduction in that Benchmark on or before the effective date of rates requested in this docket of January 1, 2014. No party contests the use of a $4.50/dt Benchmark in establishing rates for this proceeding and no other party submitted evidence on this issue. The Commission has carefully examined this proposal and concludes that the use of a $4.50/dt Benchmark for purposes of establishing rates in this proceeding, subject to Piedmont’s conditional obligation to file for a reduction in such Benchmark, is fair and reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 25

The evidence for this finding is contained in the Stipulation, as supported by the Supplemental Testimony of Company witness Carpenter.

The stipulated rate design and rates, necessary and appropriate to provide Piedmont a reasonable opportunity to recover the stipulated revenue requirement in this docket, are reflected in Exhibits C, J, and K to the Stipulation. Exhibit C sets forth the projected rates and revenues resulting from the stipulated rate design, Exhibit J shows the percentage increase by customer class, and Exhibit K sets out the discrete elements comprising Piedmont’s stipulated rates. In Mr. Carpenter’s Supplemental Testimony, he testified that “the rates agreed to as part of the Stipulation were the product of give and take negotiations between the Stipulating Parties” and that they were “highly favorable to Piedmont’s customers in comparison to Piedmont’s proposed rates.”

No party has contested the use of the rates and rate design elements set out in Exhibits C, J, and K to the Stipulation and no other party has submitted evidence supporting any alternative rate design or rate elements (other than the Company’s filed case). Based upon the Stipulation and other record evidence in this proceeding regarding rate design and individual rate elements, the Commission finds the stipulated rate design and rate elements to be reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 26

The evidence supporting this finding is contained in the Petition, the Direct Testimony of Company witnesses Skains and Gaglio, the Direct and Supplemental Testimony of Company witness Carpenter, and the Stipulation.

In its Petition, Piedmont indicated that it was incurring substantial and ongoing capital expenses associated with efforts to comply with federal pipeline safety and integrity requirements. In order to address the magnitude and impact of its capital investments required to comply with federal pipeline safety and integrity requirements on a going-forward basis, and as authorized by G.S. 62-133.7A, Piedmont proposed the adoption of an Integrity Management Rider or IMR mechanism in its tariffs. According to Piedmont, this mechanism would help preserve the ability of the Company to earn its allowed return on equity resulting from the rate case, on an intra-rate case basis, and would avoid the need for multiple annual "pancaked" rate cases that might otherwise be necessary to address the significant new capital investments associated with compliance with federal pipeline safety and integrity requirements.

In his Direct Testimony, Piedmont's Chairman, President, and Chief Executive Officer, Thomas Skains, identified the extraordinary nature of the Company's ongoing capital investments driven by compliance with federal pipeline safety and integrity requirements and emphasized the importance of pipeline safety to the Company, its customers, and the public in general. Mr. Skains also indicated that the levels of ongoing capital investment in pipeline integrity compliance activities, which do not generate any offsetting revenues, would require a series of "pancaked" rate cases on a 12 to 18 month interval in the absence of some bridge mechanism to provide rate relief in between general rate case filings. Finally, Mr. Skains offered his opinion that the regulatory costs and efforts involved with multiple and repeated general rate case proceedings driven solely by the capital investments incurred in compliance with federal pipeline safety and integrity requirements was not in the public interest.

In his Direct Testimony, Piedmont's Senior Vice President and Chief Utility Operations Officer, Victor Gaglio, who is responsible for the Company's efforts to comply with federal pipeline safety and integrity requirements, set out a detailed description of the federal Transportation Integrity Management Planning (TIMP) and Distribution Integrity Management Planning (DIMP) processes required of the Company. He also described in some detail the Company's evolving techniques and efforts to comply with TIMP and DIMP requirements as well as the Company's future planned compliance activities. In his testimony, Mr. Gaglio described the differing nature of TIMP and DIMP compliance activities and the fact that federal regulation (and potentially state regulation) was an actively evolving process that could generate substantial additional compliance requirements in the future and that the full scope of those requirements could not be known at this time. Mr. Gaglio also described how the Company (and the local distribution company industry as a whole) was transitioning from a primarily Direct Assessment approach to TIMP compliance to a broader based approach which included more utilization of In-Line Assessment (smart pigging) and pressure testing techniques, both of which are more effective but also more capital intensive than Direct Assessment in determining the condition of the facilities being tested. Finally, Mr. Gaglio testified that Piedmont projected an average of approximately $150 million per year in new capital investment associated with TIMP/DIMP compliance for each of its fiscal years 2014, 2015 and 2016. According to

Mr. Gaglio, this level of capital investment in TIMP/DIMP compliance represents approximately 50% of Piedmont's total capital budget for each of these years and is equivalent to roughly a 10% increase in Piedmont's total rate base for each of those years.

In his Direct Testimony, Mr. Carpenter explained the Company's proposed IMR mechanism and provided a proposed form of such rider as Exhibit__(DRC-4). Mr. Carpenter reiterated the Company's projected annual capital investment in TIMP/DIMP compliance costs for fiscal years 2014 through 2016 of approximately $150 million per year and offered several reasons why a rider mechanism is justified in this situation. First, Mr. Carpenter affirmed that capital investments incurred at the rate projected by the Company for its fiscal years 2014 through 2016, in the absence of any offsetting additional revenues, will require frequent and repeated general rate case proceedings in order to fold such capital investments into Piedmont's rate base and permit Piedmont to begin to earn a return on these investments, even if the other factors underlying its rates do not change materially. Second, Mr. Carpenter noted that Piedmont's more usual rate case interval has historically ranged from two to five years and as such, it was clear that TIMP/DIMP spending was going to drive rate case filings at a much higher frequency than has been experienced in the past. Third, Mr. Carpenter noted that the regulatory expense incurred by the Company to prosecute a general rate case proceeding, which is recovered from Piedmont's customers, typically runs in the range of $1 million. In the event Piedmont was required to file three consecutive rate cases in each of its fiscal years 2014, 2015, and 2016, the approximate rate case expense would likely be in excess of $3 million. Finally, Mr. Carpenter testified that multiple repeated annual rate case filings, driven solely by TIMP/DIMP compliance costs, would be administratively inefficient and would induce regulatory fatigue in the Company, the Public Staff, and the Commission.

Mr. Carpenter's proposed solution to the prospect of repeated annual rate filings driven by TIMP/DIMP compliance is a rider mechanism that would provide an annual adjustment to Piedmont's rates to compensate for the costs associated with its capital investment in TIMP/DIMP projects. The costs proposed to be recovered through such a rider mechanism would include taxes, depreciation and return but would not include any O&M expense. Such costs also would be limited to TIMP/DIMP compliance investments. According to Mr. Carpenter, such a mechanism would effectively preserve the normal rate case processes and intervals while providing a "bridge" to the Company between rate cases, solely with respect to its safety and integrity investments, that would help preserve the Company's ability to earn its allowed rate of return in the interim. In his testimony, Mr. Carpenter also pointed out that Commission approval of such a rider mechanism is plainly authorized under G.S. 62-133.7A, and that similar infrastructure rider mechanisms have been adopted in many states to address the issue of extraordinary infrastructure improvement costs.

In the Stipulation, Piedmont, the Public Staff, and CUCA support the adoption of a revised form of IMR mechanism for Piedmont. That revised mechanism is discussed in Paragraph 9 of the Stipulation and a copy is attached thereto as Exhibit F. In his Supplemental Testimony, Mr. Carpenter asserts that the revised IMR mechanism included with the Stipulation is fair, just and reasonable and further contends that it will "help ensure the orderly implementation of efforts to comply with federal and state laws and regulations around integrity, reliability, and safety while delaying or deferring rate case filings prompted solely by the incurrence of integrity related compliance costs."

No other party submitted evidence on the issue of the proposed Integrity Management Rider Mechanism.

The Commission has carefully considered the evidence in this proceeding related to the proposed IMR mechanism and has reached the following conclusions. First, the Commission concludes that the form of IMR mechanism attached as Exhibit F to the Stipulation falls within the scope of G.S. 62-133.7A. That statute authorizes the Commission to adopt “a rate adjustment mechanism to enable the company to recover the prudently incurred capital investment and associated costs of complying with federal gas pipeline safety requirements, including a return based on the company’s then authorized return.” In this case, the proposed form of IMR attached to the Stipulation provides for the recovery of return, taxes, and depreciation on capital investment associated with federal gas pipeline safety requirements in a manner consistent with the statute and in the same fundamental manner that Piedmont is permitted to recover those items of its cost of service in a general rate case proceeding. This approach to IMR cost recovery is reasonable and consistent with statutory requirements and normal regulatory practices.

Second, the Commission concludes that the version of the IMR mechanism proposed for adoption and implementation in the Stipulation is more favorable to customers than that originally proposed by the Company because it provides for a significant and escalating credit to amounts otherwise recoverable from customers derived from payments made to the Company by special contract customers (who are not otherwise subject to the rider mechanism). It is also more favorable to customers because it provides for a single annual adjustment to rates rather than the bi-annual adjustment proposed in the Company’s originally proposed version of the mechanism. This change reduces the total cost burden on customers from the rider mechanism and increases regulatory lag associated with the Company’s recovery of the costs of investment in federal safety and integrity projects. Finally, the revised IMR mechanism expressly provides for Commission review of the mechanism at the earlier of Piedmont’s next general rate case proceeding or four years from the effectiveness of the mechanism and also specifically grants any party the right to petition the Commission to terminate or modify the mechanism at any time on the grounds that the rider mechanism, as approved by the Commission, is no longer in the public interest.

Third, consistent with the requirements of G.S. 62-133.7A, the Commission concludes that adoption and implementation of the IMR mechanism attached to the Stipulation as Exhibit F is in the public interest. The Commission finds the uncontested evidence of Piedmont’s required capital expenditures on TIMP/DIMP compliance convincing. It is equally persuaded that regular and repeated general rate case proceedings, otherwise necessary to roll such investments into Piedmont’s rate base, would be a detriment to Piedmont, its customers, and the Public Staff and would serve no purpose other than to increase regulatory costs paid by ratepayers and the regulatory burden on all parties who participate in Piedmont’s general rate proceedings, including the Commission. The Commission recognizes that separately accounting for TIMP/DIMP compliance costs and addressing them through the rider mechanism on an intra-rate case basis effectively isolates those costs from other aspects of Piedmont’s cost of service, but the Commission is satisfied that the public interest is protected from any potentially adverse impacts from such treatment through a variety of means, including the limited nature of the costs recoverable through the rider mechanism, the special contract crediting provision contained therein, the mandatory and permissive review provisions contained in the rider, and the Commission's general and continuing oversight of the Company's earnings.

Finally, the Commission believes that implementation of the stipulated IMR mechanism will promote public safety by supporting the timely recovery of costs associated with pipeline safety and integrity expenditures by the Company. Safety and reliability of utility infrastructure is of critical importance to the State and this Commission, and this mechanism facilitates the accomplishment of that goal.

Based on the foregoing, and in the absence of any evidence to the contrary, the Commission finds the Integrity Management Rider mechanism attached as Exhibit F to the Stipulation to be fair, reasonable, in the public interest, and appropriate for adoption in this proceeding.

The Commission notes that current federal pipeline safety regulations are proving to be increasingly expensive. Piedmont witness Gaglio testified that complying with current federal pipeline safety regulations will require half billion dollars of non-revenue producing capital expenditures. Further, he stated that it is possible that future additional regulations "will only add to Piedmont's projected expenditures in this area." Mr. Gaglio testified about the unique nature of Piedmont's system in North Carolina stating that Piedmont has a relatively new transmission and distribution system, it has no cast iron or unprotected steel pipe in use and has not suffered a serious gas leak incident (other than those caused by third-party actions) in the State in recent memory. Additionally, Piedmont witness Skains made clear his Company's commitment to safety. He testified that Piedmont's "number one operational priority is the safety of the general public, our customers and our employees." The Commission supports Piedmont's commitment to safety. The Company's system may be "relatively new," but as Mr. Gaglio stated, "Given the complex and dynamic operating conditions that these infrastructure assets are subjected to over decades of service, it is not uncommon for damage or degradation to occur to both plastic and steel pipelines."

Both the Commission and the Company understand that complacency is not an option. However, both the Commission and Piedmont must be aware of the impact on ratepayers of any expensive capital investment. It is imperative that pipeline safety regulations promulgated by the federal government be cost-effective and take into consideration the very real impact that cost increases have on customers. Federal regulations apply to all operators nationwide and, as Mr. Gaglio testified, Piedmont's system is unique in some respects. The federal rule-making process includes the issuance of a notice of proposed rulemaking prior to establishing new regulations. The existence of an Integrity Management Rider should not impact Piedmont's participation in the process of writing new federal regulations. The Commission expects Piedmont to take a pro-active role in ensuring that new federal pipeline safety regulations are reasonable for Piedmont's ratepayers and the general public in North Carolina.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 27

The evidence for this finding is contained in the Stipulation at Paragraph 10 and Exhibit E.

Under Piedmont's MDT mechanism, certain base and heat factors, as well as "R" values, are needed in order to make the calculations periodically required under that mechanism. These values are established and updated in general rate proceedings. The Stipulating Parties have provided updated factors in this proceeding as reflected in Paragraph 10 and Exhibit E of the Stipulation. These values are not contested and no other party has offered evidence supporting other factors. Based on the Stipulation, and the other record evidence in this proceeding, the Commission concludes that the updated MDT factors identified on Exhibit E to the Stipulation are reasonable and appropriate and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 28

The evidence for this finding is contained in the Company's initial filing, the Stipulation and in the Supplemental Testimony of Company witness Carpenter.

In Piedmont's Petition, supported by the Direct Testimony of Company witness Carpenter, the Company proposed to amortize and recover a number of previously deferred regulatory assets including PIM O&M expenses and environmental assessment and clean-up costs. It also proposed to amortize and recover certain Robeson LNG Project development costs. In Paragraph 11 of the Stipulation, the Stipulating Parties propose certain agreed upon changes to the Company's proposed amortizations and recovery of the following costs: (a) PIM O&M costs; (b) EasternNC deferred O&M expenses; (c) environmental assessment and clean-up costs; (d) Robeson LNG development costs; and (e) NCNG OPEB costs. The PIM O&M costs subject to amortization over a five-year period, beginning January 1, 2014, are $17,348,593 and represent the unrecovered costs accumulated by the Company through August 31, 2013, net of regulatory amortizations through December 31, 2013. The EasternNC deferred O&M expenses subject to amortization is the remaining balance at December 31, 2013,of $6,259,460 amortized over the remaining 82 month period beginning January 1, 2014, using levelized amortization with interest at the net-of-tax overall rate of return of 6.55%. The environmental assessment and clean-up costs subject to amortization over a five-year period, beginning January 1, 2014, include O&M costs through August 31, 2013, of $6,346,642. The parties also agreed that the Company will file annual reports included with its annual manufactured gas plant (MGP) filing that provide details on the environmental assessment and clean-up costs incurred and the state or federal environmental requirement that caused the need for the expenditure to be deferred. The parties agreed that $1,208,574 of Robeson LNG development costs should be amortized over a 38 month period beginning January 1, 2014. The deferred NCNG OPEB costs subject to amortization include the December 31, 2013, balance of $414,650 to be amortized over the remaining five-year period beginning January 1, 2014. The Stipulating Parties also propose a continuation of the existing regulatory asset treatment for ongoing PIM O&M costs. The Stipulating Parties support the amortization periods set forth in Paragraph 11 of the Stipulation and the ongoing interim deferral mechanism for PIM O&M costs. No party has opposed the proposals contained in Paragraph 11 of the Stipulation and no other evidence has been submitted regarding these issues.

The Commission has carefully considered the proposed amortization periods and related matters set forth in Paragraph 11 of the Stipulation, as well as all record evidence on the amortization of these regulatory assets, and concludes that the stipulated amortization treatment and specified amortization periods are consistent with the Commission's prior treatment of similar costs and are otherwise fair and reasonable and should be approved. The Commission further concludes that the proposed continuation of the existing regulatory asset treatment for ongoing PIM O&M costs is fair and reasonable and should be approved. Additionally, the Commission concludes that Piedmont shall be required to file annual reports included with its annual MGP filing that provide details on the environmental assessment and clean-up costs incurred and the state or federal environmental requirement that caused the need for the expenditure to be deferred.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 29

The evidence for this finding is contained in the Stipulation and the Supplemental Testimony of Company witness Carpenter.

North Carolina Session Law 2013-316 (House Bill 998) establishes two prospective downward adjustments in the North Carolina corporate income tax rates to be effective for tax years 2014 and 2015. In Piedmont’s case, its tax years 2014 and 2015 coincide with its fiscal years 2014 and 2015, which begin, respectively, on November 1, 2014 and November 1, 2015. In Paragraph 22 of the Stipulation, the Stipulating Parties agree that Piedmont will adjust its rates, coincident with the effectiveness of these new tax rates as to Piedmont, for the purpose of making appropriate adjustments to Piedmont’s rates as a result of the implementation of House Bill 998. In the Stipulation, Piedmont further agrees to work with the Public Staff and CUCA to develop an appropriate mechanism for making such adjustments and to file notice of such reductions with the Commission. No party opposes this plan to adjust Piedmont’s rates for reductions in income tax expense and no other evidence on this issue was presented to the Commission in this docket.

The Commission notes that it has initiated a generic proceeding in Docket No. M-100, Sub 138 to address potential issues raised by the prospective change in corporate tax rates effectuated by House Bill 998 with respect to all major North Carolina utilities and it will continue to require Piedmont to participate in that proceeding. Nonetheless, the Commission finds that the plan for adjusting Piedmont’s rates as a result of the prospective decrease in North Carolina corporate income tax rates set forth in the Stipulation is fair and reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 30

The evidence for this finding is set forth in the Direct Testimony of Company witness Carpenter and in the Stipulation.

On July 6, 2011, in Docket No. G-9, Sub 77G, Piedmont filed a revised depreciation study for its property used and useful in providing natural gas utility service to the public consistent with the requirements of Commission Rule R6-80. Piedmont filed a revised Appendix A to that study on November 9, 2011. In making these filings, Piedmont requested that implementation of the revised depreciation rates reflected in the study be deferred until its next general rate case and that request was granted by Commission Order issued on November 22, 2011, in that docket.

In its Petition and in the direct prefiled testimony of Company witness Carpenter, the Company proposed to implement its revised depreciation rates as of the effective date of new rates approved by the Commission in this proceeding. According to Mr. Carpenter, the net impact of such implementation would be to reduce depreciation expense by approximately $10 million annually. In the Stipulation, the Stipulating Parties agreed that the revised depreciation rates should be implemented effective January 1, 2014, in order to coincide with the requested effective date of rates in this proceeding. No party contested the implementation of Piedmont's revised depreciation rates, effective January 1, 2014, as proposed in the Stipulation and no other party submitted evidence on this issue.

Based upon the Commission's prior orders in Docket No. G-9, Sub 77G, the Direct Testimony of Company witness Carpenter, and the Stipulation, the Commission concludes that implementation of the revised depreciation rates filed in Docket No. G-9, Sub 77G, effective January 1, 2014, as proposed in the Stipulation, is just and reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 31

The evidence for this finding is contained in the Direct Testimony of Company witness Carpenter and the Stipulation.

In his Direct Testimony, Company witness Carpenter proposed various changes to Piedmont's rate schedules and service regulations. Mr. Carpenter specifically identified two "significant" proposed changes as well as a number of smaller and less significant changes. In the significant category, the Company proposed to eliminate the standby fuel requirement for service under Rate Schedule 104 (Large General Interruptible Sales Service) and Rate Schedule 114 (Large General Interruptible Transportation Service) and also proposed to implement a new IMR Mechanism in its tariff. This latter change is addressed in Finding of Fact No. 26 and the evidence and conclusions supporting that finding and will not be addressed here. In conjunction with the elimination of the standby fuel requirement for the Company's interruptible services, Piedmont also proposed a two-year mitigation plan for revenue losses associated with customer migration from firm to interruptible rate schedules resulting from the elimination of the standby fuel requirement for interruptible service.

According to Mr. Carpenter, the proposal to eliminate the standby fuel requirement for interruptible service has its roots in several factors. First, Mr. Carpenter stated that Piedmont has received requests from customers to waive or eliminate the requirement and in several prior proceedings has sought case specific authority from the Commission to waive the requirement in certain circumstances. Second, Piedmont believes that its large general customers (who are the only system customers eligible for interruptible service) are, by definition, sophisticated business entities capable of assessing the risks of interruptible service and deciding for themselves whether they need back-up fuel capability. Third, the mandatory requirement for standby fuel capability may be causing some customers to incur costs they would not otherwise incur simply in order to comply with tariff eligibility requirements for less expensive interruptible service and such requirements may also be forcing customers to elect more expensive firm service when they would not otherwise require such service. Mr. Carpenter also proposes to implement a two-year margin protection mechanism to preserve the effectiveness of rates approved in this proceeding to allow Piedmont to earn its allowed return in the face of possible customer migrations from firm to interruptible service as a result of the elimination of the standby fuel requirement. That mechanism would essentially record such losses in the all customers deferred account, thereby allowing Piedmont to be kept whole from changes in customer usage and the corresponding revenue reductions prompted by the elimination of the standby fuel requirement. In support of this proposal, Mr. Carpenter notes that the Commission has previously allowed recovery of margin losses attributable to factors beyond the Company's control and has also approved a similar mechanism for Public Service Company of North Carolina, Inc. (PSNC), in Docket No. G-5, Sub 386, when PSNC eliminated the standby fuel requirement for interruptible service in its tariff in 1998.

With respect to the less significant tariff changes discussed in Mr. Carpenter's testimony, he describes these as clarifications or updates to tariff language designed to reflect changes in the Company's markets or customer practices.

In the Stipulation, in Exhibits G and H and Paragraph 30, the Stipulating Parties propose to adopt the Company's proposals with respect to the elimination of the standby fuel requirement for service under Rate Schedules 104 and 114 and the temporary margin protection plan, as well as the less significant clarifying changes described by Mr. Carpenter in his Direct Testimony.

No party contests the proposed tariff changes discussed above and no other party has submitted evidence supporting a different disposition of these proposed tariff changes.

Based upon the testimony of Company witness Carpenter and the Stipulation, as well as the Commission's prior treatment of similar issues in Docket No. G-5, Sub 386, the Commission finds that the proposed rate schedule and service regulation changes reflected in Exhibits G and H to the Stipulation are just and reasonable and should be approved and that the proposed temporary margin protection plan discussed in Paragraph 30 of the Stipulation is similarly just and reasonable and should be approved for a period of two years following implementation of the tariff changes authorized herein.

The Commission notes that the long-standing requirement for large general service interruptible customers to have standby fuel served to ensure that those interruptible customers would curtail in a timely manner when called upon to do so. Convincing arguments have been put forward in this docket supporting the elimination of the standby fuel requirement. However, Piedmont is responsible for providing reliable service to its customers. The Commission expects Piedmont to have adequate measures in place to ensure effective control over its system.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 32

The evidence for this finding is contained in the Petition, the Direct Testimony of Company witness Powers, the Stipulation, and the Supplemental Testimony of Company witness Carpenter.

In its Petition, Piedmont proposed to include in its cost of service in this proceeding, an additional $340,000 for the funding of GTI research into natural gas pipeline safety and reliability. In her Direct Testimony, Company witness Powers indicated that the Company's proposal to increase its contribution to GTI in this case was targeted at GTI's Operations

Technology Development (OTI) initiative. Ms. Powers described the OTI initiative as a "collaborative effort designed to develop, test, and implement new technologies relating to gas transmission and distribution operations, with a particular emphasis on safety and reliability." According to Ms. Powers, the intent of the initiative is to "develop new tools, equipment, software, processes, and procedures that will enhance safety, increase operating efficiency, reduce operating costs, and help maintain system reliability and integrity."

In the Stipulation, the Stipulating Parties agreed, in Paragraph 25, "that the Company may fund research and development activities through annual payments to GTI for an additional $340,000 per year, which results in a total GTI funding level of $590,000 per year . . . ."

No party has contested the increased funding of GTI proposed in the Petition and agreed to in the Stipulation and no other party has presented evidence on this issue.

The Commission has carefully considered the additional GTI funding proposed in the Stipulation, and concludes that increased funding of GTI at the level of $340,000 per year to support the development of new technologies, practices and processes which enhance the safety and reliability of natural gas transmission systems is in the public interest and is also fair and reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 33

The evidence for this finding is contained is contained in Paragraphs 4.C., 26, 27, 28, and 31 of the Stipulation. No party contests these matters and no other evidence regarding these matters has been submitted in this proceeding.

In Paragraph 4.C. of the Stipulation the Stipulating Parties agree that effective January 1, 2014, "all property taxes associated with third-party stored gas for North Carolina shall be recovered through the fixed gas cost rate element" of Piedmont's rates. This agreement modifies the treatment of these costs from prior practices where such taxes were included in Piedmont's cost of service. Inasmuch as these costs appear to fit within the broad definition of gas costs set forth in Commission Rule R1-17(k)(2)(b), the Commission finds it reasonable and appropriate to treat them accordingly and include them as a component of the Company's fixed gas costs for ratemaking purposes.

In Paragraph 26 of the Stipulation, the Stipulating Parties agree that it is appropriate to "continue the ADIT annual entry related to cost of gas and the Margin Decoupling Tracker account items in the deferred gas cost account." Based upon the Stipulation, and the agreement of the Stipulating Parties, the Commission approves the continuation of making the ADIT annual entry related to gas cost items and the Margin Decoupling Tracker account in the deferred gas cost account.

In Paragraph 27 of the Stipulation, the Stipulating Parties agree that the Company will submit, within thirty (30) days of approval of the Stipulation by the Commission, and after review and comment by the Public Staff and CUCA, tariff revisions that will allow customers to transport and/or take delivery of natural gas for use as vehicular fuel under the Company's Rate Schedules 113 and 114. The Stipulating Parties also agree to certain processes and procedures in regard to the development of this filing. This provision of the Stipulation is essentially an agreement of the Parties to take future action and presents no issue for resolution by the Commission at this time. Nonetheless, the Commission acknowledges the existence of the obligations set forth in this paragraph and supports those commitments as part of the overall resolution issues between the Stipulating Parties.

In Paragraph 28 of the Stipulation, the Stipulating Parties agree that, subject to certain conditions, Piedmont will make a filing proposing to reduce its Benchmark, effective January 1, 2014, to a rate more reflective of the current wholesale market price of natural gas. This provision of the Stipulation is essentially an agreement of the Parties to take conditional future action and presents no issue for resolution by the Commission at this time. Nonetheless, the Commission acknowledges the existence of the obligations set forth in this paragraph and supports those commitments as part of the overall resolution issues between the Stipulating Parties.

In Paragraph 31 of the Stipulation, the Stipulating Parties agree that the appropriate context in which the Public Staff should conduct its investigation of Piedmont required by the Commission's *Order on Motion for Clarification* (issued September 3, 2013 in Docket No. M-100, Sub 113A) is Piedmont's next general rate proceeding. This agreement is based upon the Public Staff's interpretation of the Commission's order cited above. The Commission has no objection to this interpretation of its order directing the Public Staff to investigate certain matters related to Piedmont and approves the substance of this Paragraph of the Stipulation.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 34

The evidence supporting this finding is contained in the Petition, Form G-1, the testimony and exhibits of the witnesses, the Stipulation, and the entire record in this proceeding.

As fully discussed above, the provisions of the Stipulation are the product of the give-and-take of settlement negotiations between Piedmont, CUCA, and the Public Staff. As a result, the Stipulation reflects the fact that each party to the Stipulation agreed to certain provisions that advanced the other's interests. The end result is that the Stipulation strikes a fair balance between the interests of Piedmont and its customers. As discussed above, the Commission has independently 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. Therefore, the Commission approves the Stipulation in its entirety.

IT IS, THEREFORE, ORDERED as follows:

1. That the Stipulation is hereby approved in its entirety.

2. That the Company is hereby authorized to adjust its rates and charges in accordance with the Stipulation and this Order (as such rates may be adjusted for any changes in the Benchmark, and changes in Demand and Storage Charges prior to the effective date of the revised rates) effective for service rendered on and after January 1, 2014.

3. That the Company is authorized to implement the Integrity Rider Mechanism attached to the Stipulation as Exhibit F effective January 1, 2014.

4. That the Company is authorized to implement the changes to its Rate Schedules and Service Regulations attached to the Stipulation as Exhibits G and H effective January 1, 2014.

5. That the Company shall file clean versions of the new and revised tariffs and service regulations to comply with this Order within five (5) days from the date of this Order.

6. That in the true-up of fixed gas costs for periods subsequent to January 1, 2014, in proceedings under Commission Rule R1-17(k), the Company shall use the fixed gas costs allocations set forth in Exhibit D to the Stipulation.

7. That the Margin Decoupling Tracker mechanism factors set forth on Exhibit E to the Stipulation are approved for use in the implementation of the provisions of that mechanism subsequent to January 1, 2014.

8. That the Company is authorized to implement the other actions, practices, principles, and methods agreed upon in the Stipulation.

9. That the Company shall send the notice attached hereto as Attachment A to its customers beginning with the billing cycle that includes the rate changes approved herein.

ISSUED BY ORDER OF THE COMMISSION.
This the 17th day of December, 2013.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

Commissioner Don M. Bailey did not participate in this decision.

SCHEDULE 1

PIEDMONT NATURAL GAS COMPANY
Docket No. G-9, Sub 631
STATEMENT OF NET OPERATING INCOME FOR RETURN, RATE BASE AND OVERALL RETURN
For The Test Year Ended February 28, 2013

Line No.	Item	Per Company	Settlement Adjustments	After Settlement Adjustments	Rate Increase	After Rate Increase
		(a)	(b)	(c)	(d)	(e)
	NET OPERATING INCOME FOR RETURN					
	Operating Revenues:					
1	Sales and transportation of gas	$756,725,430	$50,868	$756,776,298	$30,658,314	$787,434,612
2	Electric Generation Revenues	86,319,158	-	86,319,158		86,319,158
3	Special Contract Revenues	13,640,392	-	13,640,392		13,640,392
4	Other operating revenues	3,761,745	39,528	3,801,273		3,801,273
5	Total operating revenues	860,446,725	90,396	860,537,121	30,658,314	891,195,435
6	Cost of gas	405,170,964	13,734,030	418,904,994		418,904,994
7	**Margin**	455,275,761	(13,643,634)	441,632,127	30,658,314	472,290,441
	Operating Expenses, Excl COG:					
8	Operating and maintenance	191,088,326	(16,326,577)	174,761,749	255,754	175,017,503
9	Depreciation	79,248,132	(829,275)	78,418,857		78,418,857
10	General taxes	22,967,361	(1,851,242)	21,116,119		21,116,119
11	State income tax (6.9%)	7,902,029	493,972	8,396,001	2,097,777	10,493,778
12	Federal income tax (35%)	37,247,445	2,332,762	39,580,207	9,906,674	49,486,881
13	Amortization of investment tax credits	(229,226)	-	(229,226)		(229,226)
14	Total operating expenses, excl COG	338,224,067	(16,180,360)	322,043,707	12,260,205	334,303,912
15	Interest on customer deposits	1,042,351	-	1,042,351		1,042,351
16	Amortization of debt redemption premium	-	-			
17	Net operating income for return	$116,009,343	$2,536,726	$118,546,069	18,398,109	$136,944,178
	RATE BASE					
18	Plant in service	$3,246,683,144	($75,653,567)	$3,171,029,577		$3,171,029,577
19	Accumulated depreciation	(1,041,287,233)	8,795,679	(1,032,491,554)		(1,032,491,554)
20	Net plant in service	2,205,395,911	(66,857,888)	2,138,538,023		2,138,538,023
21	Allowance for Working Capital	179,902,052	(22,680,013)	157,222,039		157,222,039
22	Deferred Income Taxes	(473,326,437)	-	(473,326,437)		(473,326,437)
23	Unamortized debt redemption premium	-	-			
24	Original cost rate base	$1,911,971,526	($89,537,901)	$1,822,433,625	$0	$1,822,433,625
25	Overall Rate of Return on Rate Base	6.07%		6.50%		7.51%

ATTACHMENT A

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. G-9, SUB 631

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Piedmont Natural Gas	)	
Company, Inc. for a General Increase	)	PUBLIC NOTICE
in its Rates and Charges	)	

The North Carolina Utilities Commission issued an Order allowing Piedmont Natural Gas Company, Inc. (Piedmont or the Company) to increase its rates and charges by approximately $31 million annually, or 3.58% overall, effective January 1, 2014.

On May 31, 2013, Piedmont filed an application seeking a general increase in its rates and charges, implementation of a new Integrity Management Rider mechanism, implementation of new depreciation rates, updates and revisions to the Company's service regulations and tariffs, amortization of various deferred expenses, and proposed additional funding for gas distribution research activities conducted by the Gas Technology Institute.

In its application, the Company requested an increase of approximately $80 million annually. The Company stated that the rate increase was needed because it has been adding customers and making capital improvements in its utility properties and because it had been required to invest substantial capital in order to comply with federal pipeline safety and integrity regulations and requirements. The reasons cited by the Company in support of its request for a rate increase were to allow it to maintain its facilities and services in accordance with the reasonable requirements of its customers, to compete in the market for capital funds on fair and reasonable terms, and to produce a fair profit for its stockholders.

The increase approved by the Commission was the result of a stipulation (Stipulation) entered into between the Company and other parties to the proceeding, including the Public Staff – North Carolina Utilities Commission. The Commission notes that the increase to specific classes of customers will vary in order to have each customer class pay its fair share of the cost of providing service.

Overall, the Commission has approved a residential rate increase for the Company of 4.31%. This represents an increase to the typical residential bill of approximately $30 per year or $2.50 per month. These approved increases are associated with allowed expenses and return on investment only and do not contemplate increases or decreases that may occur in association with gas cost adjustments to rates as allowed by North Carolina law.

The Commission has also approved an Integrity Management Rider mechanism, which will allow the Company to recover the capital related costs of compliance with federal pipeline and distribution integrity management requirements on an intra-rate case basis. This mechanism will facilitate timely recovery of costs related to capital investment mandated by federal law and will help to avoid otherwise unnecessary general rate proceedings.

A list of approved rates can be obtained from the Company's website, www.piedmontng.com, or at the Office of the Chief Clerk of the Commission, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, where copies of the Commission's Order and the Stipulation are available for review by any interested party. The Commission's Order, the Stipulation, and other filings in this docket, can be viewed/printed from the Commission's website at http://www.ncuc.commerce.state.nc.us using the Docket Search function.

ISSUED BY ORDER OF THE COMMISSION.
This the 17th day of December, 2013.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

(SEAL)

DOCKET NO. SP-165, SUB 3

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of CPI USA North Carolina, LLC,	)	
for Issuance of Amended Certificates of Public	)	ORDER ADDRESSING START DATE
Convenience and Necessity, for Registration of	)	FOR FACILITIES' DESIGNATIONS
New Renewable Energy Facilities, and Request	)	AS NEW RENEWABLE ENERGY
for Determination as a Renewable Energy	)	FACILITIES
Resource	)	

BY THE COMMISSION: On January 28, 2013, the Commission issued an Order requesting comments regarding the issue of when renewable energy facilities owned by CPI USA North Carolina, LLC (CPI), should be considered to be "new" for purposes of the issuance of renewable energy certificates (RECs). The Order stated that on December 17, 2009, the Commission issued an Order finding that these facilities, located in Southport and Roxboro, should be considered "new renewable energy facilities" pursuant to G.S. 62-133.8(a)(5). The Order further noted that the Commission's decision to approve the facilities as "new" renewable energy facilities, rather than simply as renewable energy facilities, was predicated on then owner, EPCOR USA North Carolina, LLC, completing a substantial reconstruction to convert both facilities to burn a mix of coal, wood waste, and tire-derived fuel (TDF). The December 17, 2009 Order, however, did not state a specific date or milestone upon which the facilities would be considered to be "new."

On November 20, 2012, the Public Staff filed comments in which it stated that it had reviewed generation data from the facilities for the period from January, 2007, to June, 2012, and also reviewed the timeframe of various activities and expenditures related to the renovation of the facilities. Based on its review, the Public Staff stated its belief that action by CPI's board of directors in July of 2008 is the appropriate start date to consider the CPI facilities as first meeting the definition of a new renewable energy facility. The Public Staff recommended that the Commission consider the RECs earned since July 2008 as eligible for REPS compliance pursuant to G.S. 62-133.8(b)(2)(e). The Public Staff stated that any RECs earned prior to July 2008 should not be eligible for use by an electric public utility for REPS compliance, but should nonetheless be eligible for use by an electric membership corporation or a municipality (provided that the RECs had been purchased by such an electric power supplier within three years of the date on which they were earned).

On March 25, 2013, Progress Energy Carolinas, Inc. (now Duke Energy Progress, Inc., or "DEP") filed a petition to intervene in this proceeding. In its petition, DEP stated that "PEC purchased RECs from CPI during the relevant 2008-2009 time period and therefore has a real and substantial interest in the matters under consideration in this docket." The Commission granted DEP's intervention request on April 1, 2013.

The Commission's January 28, 2013 Order:

1) Required CPI to: (a) provide a verified attestation documenting the actual in-service dates of the modifications that occurred at Roxboro and Southport that enabled each plant to shift a large percentage of its fuel feedstock from coal to wood waste and TDF; (b) explain how the facilities were able to qualify for 15,429 TDF RECs in 2008, well prior to the modifications described as being underway in CPI's 2009 submittals; and (c) explain why the facilities should be designated as "new" renewable energy facilities for generation that occurred prior to the modifications.

2) Required the administrator of the North Carolina Renewable Energy Tracking System (NC-RETS) to file, under seal, confidential data regarding RECs that had been issued for the CPI facilities by month, up to and including December of 2012, including whether any such RECs had been acquired by an electric public utility and whether any such RECs acquired by an electric public utility had been retired toward compliance or placed in a compliance sub-account. The Commission also requested that the NC-RETS administrator file comments as to the feasibility of implementing the Public Staff's recommendation and the ability of NC-RETS to assure that specific vintages of RECs that had been issued for the Roxboro and Southport facilities are not used for compliance by an electric public utility.

3) Required the Chief Clerk to serve a copy of the Order on Dominion North Carolina Power; Duke Energy Carolinas, LLC; and DEP.

On February 15, 2013, CPI filed the information requested by the Commission's January 28, 2013 Order. CPI detailed the in-service dates, by month, of upgrades to the Roxboro and Southport plants. For Roxboro, $15.5 million in upgrades were installed in 2009, and $16.9 million in upgrades were installed in 2010. For Southport, $17.2 million in upgrades were installed in 2009, and $34.9 million in upgrades were installed in 2010. The only expenditures in 2008 were for front end loaders at Roxboro, which CPI stated cost $350,284.

In its February 15, 2013 filing, CPI stated that the Company started testing at the facilities as early as 2007 to evaluate the ability of each to operate using wood waste and TDF. CPI stated that, "while all modifications were not completed until later, it was still possible for EPCOR/CPI to determine the energy production data for each fuel source prior to the completion of the modifications." CPI cited Commission Rule R8-67(d)(1), which states as follows:

> Renewable energy certificates (whether or not bundled with electric power) claimed by an electric power supplier to comply with G.S. 62-133.8(b), (c), (d), (e) and (f) must have been earned after January 1, 2008 ...

CPI also noted Commission Rule R8-67(h)(4), which states that:

> Beginning June 1, 2011, renewable energy facilities registered in NC-RETS may only enter historic energy production data for REC issuance that goes back up to two years from the current date.

Further, CPI referred to the Commission's December 10, 2010 Order in Docket No. E-100, Subs 113 and 121, in which the Commission ruled that:

> To ensure that all facilities have an adequate opportunity to register with the Commission and with NC-RETS and to have their historic energy production data dating back to January 1, 2008, reported to NC-RETS, the Commission finds good cause to extend the deadline until June 1, 2011, for REC issuances based upon historic energy production data.

CPI stated that, based on the Commission's December 10, 2010 Order, CPI registered its historic RECs back to January 1, 2008, in NC-RETS "within the time period allowed." CPI stated further:

> Because EPCOR/CPI began testing at its Facilities in 2007 and modifications of its Facilities in 2008, received its registration as a new renewable energy facility in 2009 and relied [is] Commission Rule R8-67(h)(4) and the Commission's subsequent December 10 Order Extending Deadline for Issuance of Historic RECs, its 2008 TDF RECs are qualified.

In response to the Commission's question as to why CPI's facilities should be considered to be "new" renewable energy facilities for generation that occurred prior to the modifications, CPI stated that:

> ...EPCOR/CPI made significant investments in modification and renovation of its Facilities in 2008 to convert the Facilities from 100% coal burning plants to ones that use renewable energy resources as a large percentage of their fuel feedstock. ... The facilities were converted to renewable energy facilities after the passage of Senate Bill 3 and contemporaneously with the adoption of rules and other Commission orders about the operation of the new law. CPI has made every effort to comply with the law, regulations and Commission orders as they have developed during the implementation of the new law.

On March 25, 2013, the NC-RETS administrator submitted the information, under seal, requested by the Commission in its January 28, 2013 Order. The administrator provided details as to the RECs issued each month for the Southport and Roxboro facilities and information as to the then-current NC-RETS account holders that held the RECs in their accounts. Some of the RECs produced by CPI's facilities were, in fact, owned by an electric public utility. In response to the Commission's request to comment on the feasibility of implementing the Public Staff's recommendations, the administrator stated: "NC-RETS does not currently have a way to prevent certain utility types from retiring certain vintages of RECs from specific projects as the Public Staff recommended."

G.S. 62-133.8(a)(5) defines a "new renewable energy facility" as, among other things, a "renewable energy facility" that was placed into service on or after January 1, 2007.[1] G.S. 62-133.8(a)(8) defines a "renewable energy facility" as a generation facility, other than hydroelectric power facilities larger than 10 megawatts, that either generates electric power by use of a renewable energy resource, generates combined heat and power from a renewable energy resource, or is a solar thermal facility.[2]

The CPI facilities were initially placed into service long before 2007, seemingly disqualifying them from designations as "new" renewable energy facilities. However, the Commission has found that older facilities such as those owned by CPI that are modified after January 1, 2007, in order to facilitate the use of renewable energy resources may be designated as "new" renewable energy facilities.[3] The Commission has held that the determinative factor in classifying a facility as "new" should be whether substantial investment or improvement was necessary for the facility to begin generating some or all of its electricity from a renewable energy resource.[4] The salient point is that the in-service dates of the modifications determine whether a facility that uses renewable energy resources is designated a "renewable energy facility" or a "new renewable energy facility."[5] Thus, CPI's facilities are considered "renewable energy facilities" for the purposes of RECs produced after January 1 2007, and prior to any substantial investment or improvement necessary for the facility to begin generating some or all of its electricity from a renewable energy resource. Following the relevant investment or improvement, CPI's facilities are considered "new renewable energy facilities."

[1] The definition also includes facilities that delivered power to NC GreenPower Corporation prior to 2007, and certain hydroelectric facilities.

[2] As relevant to the CPI situation, G.S. 62-133.8(a) defines "renewable energy resource" to include biomass resources, including wood waste. The Commission has found that trees, tree waste, and the natural rubber portion of TDF are renewable energy resources.

[3] See the Commission's June 13, 2008 Order Approving Application, Issuing Certificate, and Accepting Registration in Docket No. SP-161, Sub 1, In the Matter of Application of Coastal Carolina Clean Power, LLC, for a Certificate of Public Convenience and Necessity to Construct a Cogeneration Plant in Duplin County, North Carolina, and Registration as a New Renewable Energy Facility, accepting the registration statement filed by Coastal Carolina Clean Power, LLC, for a 32-MW biomass-fueled cogeneration facility as a new renewable energy facility. Since 1986 the facility had operated as a coal-fired plant. However, the coal-fired plant ceased operations on April 26, 2007, and underwent an estimated $11,300,000 renovation, including extensive equipment modifications and additions, resulting in the ability to burn various wood waste products to generate electricity and create steam.

[4] See the Commission's June 18, 2013 Order Accepting Registration as a Renewable Energy Facility in Docket No. SP-2285, Sub 1, In the Matter of Application of Weyerhaeuser NR Company for Registration of a New Renewable Energy Facility.

[5] RECs from a new renewable energy facility may be used by an electric public utility to comply with REPS; RECs from a renewable energy facility may not.

The Commission has carefully reviewed the verified data that CPI filed on February 15, 2013, detailing the in-service dates of its modifications to the Southport and Roxboro plants that allowed those plants to shift a large percentage of their fuel feedstock from coal to wood waste and TDF. The Commission has also carefully reviewed the REC production data provided by the NC-RETS administrator. Based on those two data sources, the Commission finds that CPI made substantial modifications to both facilities in late 2009 that allowed the plants to use significantly more renewable energy resources starting in early 2010. (Additional modifications in 2010 further increased the plants' use of renewable energy resources.) The Commission therefore concludes that it would be appropriate to designate the Southport and Roxboro plants as being "renewable energy facilities" during 2008 and 2009, and "new renewable energy facilities" beginning in 2010.

However, the Commission is concerned that at least one electric public utility has purchased RECs from CPI in reliance on the Commission's December 17, 2009 Order that designated CPI's facilities as new renewable energy facilities, without qualification as to the in-service date of CPI's planned modifications. In addition, a decision to retroactively designate some of CPI's RECs as being from a renewable energy facility, rather than from a "new" renewable energy facility, would present administrative and auditing costs without commensurate benefits. Therefore, the Commission declines to take any further action in this matter.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 31st day of October, 2013.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

kj103113.02

DOCKET NO. T-4463, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application for Certificate of Exemption to Transport Household Goods by Desi Ernesto Zerpa, d/b/a Metro Move, 2720 Pitts Drive, Charlotte, North Carolina 28205	)	ORDER DENYING APPLICATION FOR CERTIFICATE OF EXEMPTION AND ASSESSING CIVIL PENALITIES

HEARD IN: Commission Hearing Room 2115, Dobbs Building, 430 N. Salisbury Street, Raleigh, North Carolina, on Tuesday, October 23, 2012, at 10:00 a.m. and Thursday, April 11, 2013, at 9:30 a.m.

BEFORE: Commissioner William T. Culpepper, III, Presiding; Commissioner Bryan E. Beatty, and Commissioner Susan W. Rabon.

APPEARANCES:

For the Applicant:

Desi Ernesto Zerpa, d/b/a Metro Move, pro se, 2720 Pitts Drive, Charlotte, North Carolina 28205

For the Using and Consuming Public:

Lucy Edmondson, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Dobbs Building, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: On June 30, 2011, Desi Ernesto Zerpa, d/b/a Metro Move, (Mr. Zerpa), pursuant to G.S. 62-261(8) and Commission Rule R2-8.1, filed an application with the North Carolina Utilities Commission (Commission) for a Certificate of Exemption (Certificate) to transport household goods by motor vehicle for compensation within the state of North Carolina.

On July 18, 2011, the Commission Staff provided Mr. Zerpa with written acknowledgement of receipt of his Application and requested additional information to complete his application.

On December 29, 2011, Mr. Zerpa made a Confidential Compliance filing with the Commission.

On September 25, 2012, the Commission issued an Order Scheduling Application for Hearing, requiring Mr. Zerpa to appear before the Commission to discuss his application and directing the Public Staff - North Carolina Utilities Commission (Public Staff) to participate on behalf of the using and consuming public. Mr. Zerpa was ordered not to operate as a mover of household goods prior to Commission approval of his application and the purchase of the proper license plates from the Division of Motor Vehicles.

No protests were filed in this proceeding.

On October 23, 2012, the docket came on for hearing as scheduled. Mr. Zerpa appeared pro se and offered testimony in support of his application and addressed questions from the Public Staff and the Commission. Mr. Ronald Edward Ward testified at the hearing on behalf of Mr. Zerpa as a character witness. The Public Staff presented the testimony of Carol Kimball Stahl, Director of the Public Staff's Transportation Rates Division.

On October 24, 2012, the Public Staff submitted late filed exhibits into the record.

On November 26, 2012, the Public Staff filed a Confidential Brief.

On March 20, 2013, the Commission issued an Order Reconvening Hearing on Fitness and Directing Mr. Zerpa to Show Cause. In the Order, the Commission found and concluded that it had been presented with substantial evidence that Mr. Zerpa had represented himself as holding a certificate and being otherwise authorized to operate as a carrier of household goods in North Carolina in violation of G.S. 62-280.1(a). The Commission also found and concluded that it had been presented with substantial evidence that Mr. Zerpa, either under the name of Metro Move or under another name, had been operating as a de facto public utility and providing intrastate transport of household goods in the state of North Carolina without possessing a certificate of exemption as required by G.S. 62-261(8) and Commission Rule R2-8.1 in violation of G.S. 62-262(a). Finally, the Commission found and concluded that it had been presented with substantial evidence that raised serious questions regarding Mr. Zerpa's fitness to be granted a certificate to perform the service of transporting household goods within the state of North Carolina as required by G.S. 62-262(e). The Commission scheduled the docket for hearing and directed Mr. Zerpa to appear and show cause on the following issues:

(a) Should Desi Ernesto Zerpa, d/b/a Metro Move be found to have represented himself as holding a certificate and otherwise authorized to operate as a carrier of household goods in North Carolina in violation of G.S. 62-280.1(a) and assessed a civil penalty not in excess of five thousand dollars ($5,000) for such violation?

(b) Should Desi Ernesto Zerpa, d/b/a Metro Move be found to have been a de facto public utility by holding himself out as a common carrier of household goods, as defined in G.S. 62-3(7), while engaging in the intrastate transport of household goods without possessing a certificate as required by G.S. 62-261(8) and Commission Rule R2-8.1 in violation of G.S. 62-262(a) and subject to sanctions or penalties provided by G.S. 62-310(a), recoverable pursuant to G.S. 62-312?

(c) Why, in light of the evidence presented to the Commission at the October 23, 2012 hearing, should Desi Ernesto Zerpa, d/b/a Metro Move be issued a certificate to perform the service of transporting household goods within the state of North Carolina?

On April 11, 2013, the matter came on for hearing as scheduled. Mr. Zerpa appeared pro se and offered testimony in support of his application and answered questions from the Public Staff. The Public Staff presented the testimony of Carol Kimball Stahl, Director of the Public Staff's Transportation Rates Division and submitted exhibits into the record.

On May 14, 2013, the Public Staff filed its Proposed Order.

Based upon the testimony and the exhibits presented at the hearing, and the entire record in this proceeding, the Commission makes the following:

FINDINGS OF FACT AND CONCLUSIONS

1. The Commission has jurisdiction over public utilities, including those engaged in the intrastate transportation of household goods for compensation in North Carolina, as defined by G.S. 62-3(7) and (15).

2. The Commission has authority to issue certificates to applicants for the purpose of engaging in intrastate transportation of household goods for compensation in North Carolina, pursuant to G.S. 62-261(8) and Commission Rule R2-8.1.

3. Desi Ernesto Zerpa, d/b/a Metro Move is properly before the Commission, pursuant to Commission Rule R1-4(3).

4. Desi Ernesto Zerpa is the sole owner of Metro Move. Mr. Zerpa submitted an application for a certificate with the Commission on June 30, 2011. The application was still pending during this proceeding.

5. On July 18, 2012, Commission staff sent Desi Ernesto Zerpa, d/b/a Metro Move acknowledgement of receipt of his application, requesting additional information and advising him that he could not lawfully transport household goods in this state without being issued a certificate from the Commission.

6. On September 25, 2012, the Commission issued an Order Scheduling Docket for Hearing. In paragraph #6 of the Ordering section, the Commission advised Desi Ernesto Zerpa, d/b/a Metro Move, that he was not to operate as a mover of household goods within this state prior to the Commission approving his application for a certificate.

7. G.S. 62-280.1(a)(1) states, in pertinent part, that it is unlawful for a person not issued a certificate to operate as a carrier of household goods…to orally, in writing, in print, or by sign…internet…or business card…in any manner, directly or by implication, represent that the person holds a certificate or is otherwise authorized to operate as a carrier of household goods in this state.

8. Desi Ernesto Zerpa, d/b/a Metro Move, violated G.S. 62-280.1, by advertising his services in business cards as a household goods carrier to the public without first having been issued a certificate from the Commission.

9. Desi Ernesto Zerpa, d/b/a Metro Move acted as a de facto public utility by holding himself out as a common carrier of household goods, as defined in G.S. 62-3(7), while engaging in the intrastate transport of household goods without possessing a certificate in violation of G.S. 62-262(a).

10. On December 21, 2012, Desi Ernesto Zerpa, d/b/a Metro Move engaged in the intrastate transportation of the household goods of Lakeesha Love for compensation for a local move in the greater Charlotte area without a certificate, as required by G.S. 62-261(8) and Commission Rule R2-8.1.

11. Metro Move owns the domain www.bestintownmovers.com, but is not affiliated with a company called "Best in Town Movers."

12. Desi Ernesto Zerpa has distributed business cards utilizing the name of "Metro Moving Systems" which state it is "licensed, insured and bonded", none of which is true.

13. According to the Federal Motor Carrier Safety Administration (FMCSA), Metro Move does not have authority to transport household goods interstate. Metro Move did have such authority on September 25, 2008; however, the authority was listed as inactive on December 6, 2011 and reinstated on January 8, 2013.

14. On April 5, 2011, the Public Staff received a complaint from Elnita DaCosta that involved a move of her household goods on October 31, 2010. Documentation provided by Ms. DaCosta included a bill of lading showing an assignment to Southpark and a receipt showing a payment of $200 to Metro Move.

15. Ten complaints, eight of which remain unresolved, have been filed against Metro Move with the Charlotte Better Business Bureau (BBB). Due to these complaints, Metro Move has an "F" rating with the BBB. The complaints range from claims of poor service to damage to property.

16. Ms. Lakeesha Love, a Charlotte resident, retained Metro Move for a local move on December 21, 2012, because its business card stated it was a licensed, insured, and bonded company. Ms. Love filed a complaint against Metro Move with the BBB asserting that the company overcharged her for service.

17. At the hearing on October 23, 2012, Mr. Zerpa was advised by Commissioner Bryan E. Beatty that the language he was using in his business cards was misleading and unlawful.

18. Desi Ernesto Zerpa, d/b/a Metro Move should be assessed a civil penalty in the amount of $2,500 for violating G.S. 62-280.1(a).

19. Desi Ernesto Zerpa, d/b/a Metro Move should be assessed a civil penalty in the amount of $2,500 for violating G.S. 62-262(a).

20. Desi Ernesto Zerpa, d/b/a Metro Move should be denied a certificate of exemption to transport household goods in the state of North Carolina.

DISCUSSION

Mr. Zerpa's violation of G.S. 62-280.1(a)

Mr. Zerpa has represented himself as being authorized to operate as a carrier of household goods in North Carolina in violation of G.S. 62-280.1(a). G.S. 62-280.1 states, in part, that it is unlawful for a person not issued a certificate to operate as a carrier of household goods under the provisions of this Chapter to orally, in writing, in print, or by sign…internet…or business card…in any other manner, directly or by implication, represent that the person holds a certificate or is otherwise authorized to operate as a carrier of household goods in this state. Section (c) of G.S. 62-280.1 allows the Utilities Commission to assess a civil penalty not in excess of five thousand dollars ($5,000) for the violation of subsection (a) of this section.

Prior to filing his application for a certificate, Mr. Zerpa regularly distributed business cards which state that Metro Move is licensed, insured and bonded. The cards also state that Metro Move performs full service labor and storage specials. Pricing information is also indicated on the card, highlighting per hour quotes for the number of men and trucks used. While testifying on October 23, 2012, Mr. Zerpa admitted that Metro Move is not licensed, insured or bonded. Mr. Zerpa stated that Metro Move uses these business cards as a part of its direct marking strategy. According to Mr. Zerpa, the cards are placed on windshields of parked vehicles, placed in high traffic common areas, and passed out to individuals on the streets throughout the greater Charlotte area. Mr. Zerpa asserted that the cards are a promotional tactic to catch the interest of potential customers and generate leads for its clients.

The promotional tactics used by Mr. Zerpa with regards to stating that Metro Move is licensed, insured, and bonded is illegal because the cards are misleading and deceptive. Specifically, Metro Move is not licensed, insured or bonded. On the cards, Metro Move is not just advertising labor only moves, but labor and transportation. This clearly qualifies as advertising full service moves and it gives the using and consuming public the impression that Metro Move is a moving company authorized by the Commission. However, Metro Move is not authorized by the Commission to perform full service household goods moves.

Mr. Zerpa had been advised about the implications of using misleading and deceptive language in his advertising. He was warned about his activities by both the Public Staff and the Commission.

The Public Staff's witness Carol Stahl testified that she had advised Mr. Zerpa that the language on the card was misleading and that it should be changed. In support of her testimony, she provided copies of electronic mail (e-mail) that she forwarded to Mr. Zerpa from 2011 in which she expressed to him her concern regarding the business cards that he was distributing on behalf of Metro Move. She also informed him that the information on the webpage which he maintained was misleading and illegal as well. This was not the only precautionary advice that he received regarding his advertising. At the hearing on October 23, 2012, Mr. Zerpa was advised by Commissioner Beatty that the language he was using in the cards was indeed misleading. Commissioner Beatty specifically advised Mr. Zerpa that the use of misleading language with regards to the moving industry is a criminal offense and that he could be prosecuted for it.

Despite the clear and unequivocal warnings provided to him by Commissioner Beatty and the Public Staff, Mr. Zerpa did not modify the business cards, but continued to distribute them to the using and consuming public. The business cards were distributed by Mr. Zerpa as recently as December 12, 2012, while his application was still pending before the Commission.

The record shows that Mr. Zerpa's advertising was successful in inducing at least one member of the using and consuming public to purchase Metro Move's services. Ms. Lakeesha Love, a Charlotte resident, filed a complaint against Metro Move with the BBB asserting that the company overcharged her for service. In her complaint, Ms. Love noted that she retained Metro Move for a local move on December 21, 2012, because its business card stated it was a licensed, insured, and bonded company. However, she learned that the representations made by Metro Move were not true. In her opinion, Metro Move's misrepresentation placed her and her family at risk and compromised their safety by allowing random people into her home and providing access to their personal items.

Given the foregoing, the Commission finds that members of the using and consuming public can be, and have been, misled to believe that Metro Move is in fact licensed, insured, and bonded based on the language in its business cards.

Based on the facts and circumstances presented, the Commission finds and concludes that Mr. Zerpa has represented himself as holding a certificate and otherwise authorized to operate as a carrier of household goods in North Carolina in violation of G.S. 62-280.1(a) by distributing misleading business cards to the using and consuming public throughout the greater Charlotte area. Moreover, the Commission finds and concludes that Mr. Zerpa's actions with regards to distributing Metro Move's misleading and deceptive business cards were willful and without regard to the law and Commission Rules. As a result of his conduct, the Commission finds that Mr. Zerpa should be assessed a civil penalty in the amount of **$2,500** to be paid in certified funds or U.S. currency.

Mr. Zerpa's violation of G.S. 62-262(a)

Desi Ernesto Zerpa was informed twice that he was not to perform a household goods move until a certificate was issued by the Commission. On July 18, 2012, Commission staff sent Mr. Zerpa correspondence to acknowledge receipt of his application and requested additional information. The correspondence also contained a statement which informed him that he could not transport household goods in the state without first obtaining a certificate from the Commission. This was not his only written warning. On September 25, 2012, the Commission issued an Order Scheduling Hearing in this docket. In ordering paragraph #6, the Commission advised Desi Ernesto Zerpa, d/b/a Metro Move that he was not to operate as a mover of household goods within the state prior to the Commission approving his application. Despite not having a certificate, Mr. Zerpa performed household goods moves in the state of North Carolina.

It has long been determined that the Commission has authority to regulate motor carriers of household goods as "public utilities." G.S. 62-3(23)a.4. This authority also extends to persons and/or entities that may not have specifically met all of the Commission's authorization requirements. The Commission has previously stated that

> The status of an entity as a public utility does not depend upon whether it has obtained operating authority from the Commission, but rather upon whether it is in fact operating a business defined as a public utility by the General Statutes. State ex rel. Utilities Commission v. Carolina Telephone and Telegraph Co., 267 N.C. 257 (1966); State ex rel. Utilities Commission v. Mackie, 79 N.C. App. 19 (1986), modified and aff'd, 318 N.C. 686 (1987). "If an entity is, in fact, operating as a public utility, it is subject to the regulatory powers of the Commission notwithstanding the fact that it has failed to comply with G.S. 62-110 before beginning its operation" Mackie, 79 N.C. App., at 32. The same conclusion applies when an entity is required to obtain a certificate of exemption from the Commission, but fails to do so. (quoting, In Weathers Bros. Transfer Co, Inc. d/b/a Weathers Moving and Distribution v. Movers at Demand, Inc, Docket Nos. T-4176, Sub 1 and T-4171, Sub 2 (May 11, 2004)).

(citing N.C.U.C. Docket No. T-4418, Sub 1 (2012), see also N.C.U.C. Docket No. T-4422, Sub 0 (July 27, 2009)).

Based on the facts and circumstances of this docket, the Commission finds that Mr. Zerpa has operated as a de facto public utility by holding himself out as a common carrier of household goods, as defined by G.S. 62-3(7). Despite not being issued a certificate, Metro Move has performed full service moves in the state. Witness Stahl testified about the various activities which the Public Staff had become aware of due to the complaints that have been filed against Metro Move. The record shows that from 2010 – 2012, Metro Move performed a significant number of intrastate moves and interstate moves. Witness Stahl testified that Metro Move moved North Carolina residents outside of the state, without the authority of the Federal Motor Carrier Safety Administration (FMCSA). She also testified that Metro Move performed full service moves within the state of North Carolina, without first being issued a certificate of exemption from the Commission. After reviewing the Commission's certificate database and the FMCSA's mover database, witness Stahl concluded that these moves were illegal because Metro Move did not have the legal authority to perform the moves.

These unauthorized moves performed by Metro Move are reflected in the 10 complaints which have been filed against it with the BBB. As a result of these complaints, Metro Move has an "F" rating with the BBB. Mr. Zerpa has done a poor job of resolving the outstanding complaints filed against Metro Move with the BBB. According to Mr. Zerpa, several of these complaints have been pending for several years without resolution.

The Commission further recognizes that complaints continue to be filed against Metro Move with the BBB. Apparently, Ms. Love retained Metro Move for a local move of her household goods. Ms. Love was quoted a rate of $58 an hour by Metro Move. Metro Move performed the move in less than three hours; however, she was charged over the hourly rate she had been quoted. She paid $285.26, but realized she overpaid by $111.26. Despite her efforts to resolve this matter, Ms. Love has not been able to obtain a refund from Metro Move. She also has not been able to obtain an invoice regarding her move.

Mr. Zerpa had the opportunity to testify at the hearing on April 11, 2013; however, in doing so he did not dispute any of the allegations made by the Public Staff. At the October 23, 2012 hearing, witness Stahl, testified that on April 5, 2011, the Public Staff received a complaint about Metro Move from Elnita DaCosta. Ms. DaCosta informed the Public Staff that Metro Move moved her household goods in Charlotte on October 31, 2010. Ms. DaCosta provided the Public Staff with a copy of a bill of lading showing an assignment to Southpark and a receipt showing a payment of $200 to Metro Move. The NCUC number on Ms. DaCosta's bill of lading is a number that had been issued to Southpark. However, the email address used on the bill of lading and the confirmation was react123@hotmail.com, an e-mail address that the Public Staff has used to reach Desi Zerpa in the past.

During his testimony, Mr. Zerpa did not dispute that Metro Move performed the move involving Ms. DaCosta. He also did not dispute that he moved Ms. Love. However, Mr. Zerpa did assert that the move of Ms. Love's household goods was performed by volunteers and not actual Metro Move employees. In his opinion, this move was just a load only move.

Mr. Zerpa cannot claim that he used volunteers and thereby escape responsibility for his actions. Despite Mr. Zerpa's assertion, the facts and circumstances show that Metro Move hired the volunteers, provided them with training and direction on loading and off-loading the truck and paid them after the move was complete. In essence, this coordinated effort by Metro Move was a full service move performed by Metro Move.

Mr. Zerpa has established and maintains several websites which advertise moving services. In particular, the Public Staff has identified Metro Move's website as www.bestintownmovers.com. At the October 23, 2012 hearing, the Public Staff indicated that a prospective customer could learn about Metro Move and the services which it provides by reviewing the site. For example, the language on Metro Move's webpage stated that Metro Move "is able to move you anywhere in the world." Within that claim, Metro Move identified the following eight locations: Richmond, Atlanta, Raleigh, Pittsburgh, Miami, and NewYork/Tri-State. The webpage further indicated the availability of "full value insurance, general liability, cargo, and auto" and stated "Let us provide your next move instead of moving yourself." Mr. Zerpa was asked by the Public Staff about the language that was used on the site and, in particular, whether it would be reasonable for a prospective customer to believe that Metro Move was authorized to operate as a carrier of household goods in the state of North Carolina. Mr. Zerpa admitted that, based on the wording, he could see how someone could believe that Metro Move was authorized by the Commission to transport household goods.

The record shows that Mr. Zerpa has made some amendments to Metro Move's webpage after the October hearing. However, the website still contains language which could lead someone to believe that Metro Move is a moving carrier authorized by the Commission.

Specifically, the webpage states that Metro Move provides “Local Moving, Business Moving, Nationwide Moving, Full Service Packing.” Moreover, there is language which reads that “We’re moving communities (sic) one family at a time.” Furthermore, the information in subsequent website pages provides a great deal of information as to the needs of the customer. Metro Move asserts that “Our programs are designed to pinpoint the base for a (sic) affordable move.” Metro Move further asserts in the webpage that “Our movers assist in Same Day moves, Deliveries and Shuttling to Semi-Trucks.” Lastly, Metro Move states that their “Movers are equipped with tools and pads, Trained to be polite & courteous, Equipped with Dollies and straps, Build crates and professionally Load/Unload.”

The Commission finds and concludes that the language used on Metro Move’s webpage could lead a member of the using and consuming public to believe that Metro Move is a common carrier authorized by the Commission. The Commission disagrees with Mr. Zerpa’s argument that the webpage highlights his offering of transport services. Although he may intend to give the using and consuming public the impression that Metro Move provides “transporter services,” the descriptions and language contained on the webpage can be interpreted differently. Given this analysis, the Commission finds and concludes that although the webpage does include a description of transporter services, this description is incremental as to the entirety of the webpage. The majority of the website is dedicated to information describing the types of moves, price/quote information, and customer testimonials and, therefore, a reasonable member of the using and consuming public can be led to believe that Metro Move is a carrier of household goods authorized by the Commission.

G.S. 62-310(a) states that any public utility which violates any provision of this Chapter or refuses to conform to or obey any rule or regulation of the Commission shall…pay a sum up to one thousand dollars ($1,000) for each offense, to be recovered in an action to be instituted in the Superior Court of Wake County. Each day such public utility continues to violate any provision of this Chapter or continues to refuse to obey or perform any rule, order or regulation prescribed by the Commission constitutes a separate offense.

After carefully considering the evidence, the Commission finds and concludes that Mr. Zerpa operated as a de facto public utility by holding himself out as a common carrier of household goods, as defined in G.S. 62-3(7), while engaging in the intrastate transport of household goods without possessing a certificate of exemption as required by G.S. 62-261(8) and Commission Rule R2-8.1 in violation of G.S. 62-262(a). The Commission further finds that Mr. Zerpa was willful in his activities as he performed several moves while he did not have a certificate and after he was specifically informed that he could not transport household goods until a certificate was issued to him. As a result of his actions, the Commission finds and concludes that Mr. Zerpa should be assessed a civil penalty in the amount of **$2,500** to be paid in certified funds or U.S. currency**.**

Ruling on Mr. Zerpa’s Application for a Certificate of Exemption

Commission Rule R2-8.1 sets forth the specific requirements which are needed in order to obtain a certificate from the Commission. These requirements are also contained on the applications which the Commission provides to prospective applicants.

In order to obtain a certificate, an applicant must demonstrate to the Commission that it is fit, willing, and able to properly perform the service of household goods transportation within North Carolina, is familiar with the moving industry, has a reasonable and adequate knowledge of the rules and regulations governing the moving industry, including safety requirements as enforced by the N.C. Division of Motor Vehicles, and has knowledge of and will abide by the tariff requirements as established by the Commission in Maximum Rate Tariff No. 1. An applicant must also show that it is financially solvent, will maintain minimum limits of liability and cargo insurance coverage, will file proof of general liability insurance, permit only persons possessing a valid driver's license to operate the motor vehicles that will be used for transporting household goods, submit a Federal certified criminal record check, and certify that the applicant has valid authorization to work in the United States.

If an applicant cannot successfully meet the above described requirements, it is not entitled to be granted a certificate from the Commission to transport household goods.

After carefully reviewing the record including all the testimony, exhibits and filings, the Commission finds and concludes that Desi Ernesto Zerpa d/b/a Metro Move **should be denied** a certificate at this time. In making this determination, the Commission has carefully considered the issue of "fitness" with regards to Mr. Zerpa and his actions with respect to the using and consuming public.

The Commission finds and concludes that Mr. Zerpa has no regard for the law and the Commission's rules. At the hearing on April 13, 2013, Mr. Zerpa asserted that he never received a cease and desist notification from the Commission. He specifically stated that "I spoke with the Public Staff directly and that's who I've been answering to regarding (sic) for the last four years." He asserted that during that time period, he had never been told that he could not operate.

This was a false statement. The record shows that the Commission sent him correspondence acknowledging receipt of his application. In the acknowledgment, Mr. Zerpa was reminded that he could not operate as a household goods mover until a certificate was issued to him by the Commission. The acknowledgment correspondence was sent to him on July 18, 2012, by Bruce Raemakers, a Commission Transportation Analyst.

At the hearing on October 23, 2012, Mr. Zerpa admitted that he received the correspondence from Mr. Raemakers and confirmed that he was aware that he was not to transport household goods without first receiving a certificate from the Commission. His testimony on April 13, 2013, was a direct contradiction to the testimony he provided at the October 23, 2012 hearing. Witness Stahl testified that she sent several electronic messages to Mr. Zerpa in 2011 about his advertising and included in her warnings that he could not operate until a certificate was issued. Mr. Zerpa never disputed the testimony from witness Stahl that she warned him several times that he could not operate without a certificate.

The Commission also finds and concludes that despite not having authorization to operate, Mr. Zerpa has continually engaged in moves of household goods. His actions were not limited to North Carolina. As stated previously, he has performed both intrastate and interstate moves without the necessary authority to do so. Moreover, this was not a onetime occurrence, but a pattern of indifference to the law. Metro Move's activities are detailed in the complaint records of the BBB. Most recently, the Commission learned that he performed a move in the Charlotte area for Ms. Love. This move was performed by Metro Move on December 21, 2012, during a time when his application was pending and being considered by the Commission.

The Commission further finds and concludes that Mr. Zerpa acted unlawfully in distributing Metro Move's business cards which are misleading and deceptive. The record shows that Mr. Zerpa was advised that he needed to stop promoting the false claims that Metro Move is a licensed, insured, and bonded company. The Public Staff and Commissioner Beatty both instructed him that his actions with regards to using the language on the business cards were impermissible. However, despite these warnings Mr. Zerpa continued to distribute the misleading business cards which held Metro Move out as an authorized household goods mover to the using and consuming public. Mr. Zerpa testified that Metro Move distributed approximately 5,000 – 10,000 of these business cards in the year 2012. He distributed these cards well after being informed that they were misleading and thus impermissible.

The Commission finds and concludes that Mr. Zerpa has been dismissive and evasive in his testimony to the Commission. The Commission views credibility to be an important factor when considering an applicant's fitness. The Commission finds and concludes that Mr. Zerpa has not taken responsibility for his actions with regards to his illegal advertising; unauthorized moving; and in providing untruthful testimony to the Commission.

Mr. Zerpa has attempted to explain away his actions at every opportunity. This is very evident when considering his involvement with the Public Staff. The record shows that the Public Staff has had considerable interaction with him and has attempted to advise him with respect to his actions regarding both advertising and operating without a certificate. Mr. Zerpa stated that he followed the guidance of the Public Staff for four years. However, his statements are not persuasive because the facts show that he did not follow the Public Staff's guidance on any of the most important issues raised in this proceeding.

Mr. Zerpa contends that he is not operating as a certificated household goods mover, but rather is operating as a "brokerage business" that solicits business for clients. However, his advertising and webpage show a different picture of his business. Based on Mr. Zerpa's actions, the Commission views Metro Move as an unauthorized full service mover. Mr. Zerpa's recent actions have only strengthened this perception. Metro Move moved Ms. Love's household goods in December 21, 2012, and Mr. Zerpa received a citation in the state of South Carolina for performing a move without the proper authority. Mr. Zerpa's actions are not excused because they occurred outside the state of North Carolina. His continued efforts to operate without a certificate, in defiance of the law, directly reflect on his fitness. These are not issues that the Commission can easily overlook. <u>His actions clearly signify to the Commission that he does not possess the necessary fitness to be issued a certificate from this Commission.</u> Therefore, the Commission finds and concludes that Desi Ernesto Zerpa, d/b/a Metro Move should be denied a certificate to transport household goods in the state of North Carolina.

However, in making this determination, the Commission wants to emphasize that this ruling does not bar Mr. Zerpa from resubmitting an application at some later time. The Commission does not necessarily believe that Mr. Zerpa should never have the opportunity to engage in the lawful business of moving household goods. However, Mr. Zerpa must take responsibility for his unlawful conduct and pay the civil penalties assessed to him by this order. Moreover, in the event he should later apply for a certificate, Mr. Zerpa must show truthfulness in providing information to the Commission. Furthermore, in the instance of any such application, Mr. Zerpa will be required to demonstrate to the satisfaction of the Commission that he can follow the law and not operate without a certificate. Finally, the Commission finds and concludes that no application of Desi Ernesto Zerpa, d/b/a Metro Move for a certificate to transport household goods in the state of North Carolina shall be considered until such time as Mr. Zerpa fulfills the indicated monetary commitment contained in this Order.

IT IS, THEREFORE, ORDERED as follows:

1. That Desi Ernesto Zerpa, d/b/a Metro Move is hereby denied a certificate of exemption to transport household goods in the state of North Carolina.

2. That Desi Ernesto Zerpa, d/b/a Metro Move shall pay a civil penalty of **$2,500** to the Commission, Office of the Chief Clerk, for his violation of G.S. 62-280.1(a).

3. That Desi Ernesto Zerpa, d/b/a Metro Move shall pay a civil penalty of **$2,500** to the Commission, Office of the Chief Clerk, for his violation of G.S. 62-262(a).

4. That the total **$5,000** civil penalty assessed hereby shall be payable in ten (10) equal monthly installments of $500 each, into the Office of the Chief Clerk, commencing thirty (30) days following the issuance of this Order and every subsequent thirty (30) days thereafter until satisfied, in certified funds (made payable to the North Carolina Department of Commerce/Utilities Commission).

5. That the Commission may seek to recover the total **$5,000** civil penalty assessed by this Order in an action instituted in the Superior Court of Wake County, North Carolina, pursuant to G.S. 62-310(a), should Desi Ernesto Zerpa, d/b/a Metro Move fail to remit the payment as hereby ordered.

6. That this Order will be shared with the Enforcement Division of the North Carolina State Highway Patrol to monitor the activities of Desi Ernesto Zerpa, d/b/a Metro Move.

7. That Desi Ernesto Zerpa, d/b/a Metro Move shall be served with this Order by United States certified mail, return receipt requested and electronic mail, delivery confirmation requested.

ISSUED BY ORDER OF THE COMMISSION.
This the 28th day of June, 2013.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

Pb062813.01

DOCKET NO. T-4445, SUB 4

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Crystal Simpson, 3508 Garden Road, Apt. D3, Burlington, North Carolina 27215, Complainant	)	RECOMMENDED ORDER DISMISSING COMPLAINT AND ASSESSING PENALTIES
v.	)	
Lawrence Eugene Hinnant, III, d/b/a First Class Move, Respondent	)	

HEARD: Thursday, October 4, 2012, at 9:30 a.m., Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina,

BEFORE: Corrie V. Foster, Commission Hearing Examiner

APPEARANCES:

For the Complainant:

Crystal Simpson Tyson, MD,[1] *Pro Se*, 3508 Garden Road, Apt. D3, Burlington, North Carolina 27215

For the Respondent:

Lawrence Eugene Hinnant, III, *Pro Se*, 4705B, Walden Pond, Raleigh, North Carolina 27604

For the Using and Consuming Public:

Antoinette R. Wike, Chief Counsel, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BY THE HEARING EXAMINER: On June 19, 2012, Crystal Simpson (Complainant) filed with this Commission a complaint against Lawrence Eugene Hinnant, III, d/b/a First Class Move (Respondent). The Complainant alleged that on June 15, 2011, the Respondent damaged her 50 inch Samsung HDTV when the Respondent moved her household goods from Morrisville, North Carolina to Burlington, North Carolina.

[1] The Complainant married between the time of the filing of the complaint and the time of the hearing and now uses her married name, Crystal Simpson Tyson or Crystal Tyson. It has also been brought to the Commission's and the Public Staff's attention that she is a medical doctor. In this order, she will be referred to either as the Complainant or as Dr. Tyson.

On June 20, 2012, the Commission issued an Order Serving Complaint in the above-captioned docket.

On July 2, 2012, the Respondent filed its Answer to the Complaint.

On July 3, 2012, the Commission issued an Order Serving Answer to the Complaint.

On July 12, 2012, the Complainant filed notice with the Commission that she was not satisfied with the Respondent’s Answer and requested a hearing.

On August 7, 2012, the Commission scheduled a hearing on the complaint and consolidated it with a show cause proceeding.

Accordingly, the Commission ordered Lawrence Eugene Hinnant, III, d/b/a First Class Move to appear and show cause:

(a) Why First Class Move should not be found to be a de facto public utility by holding itself out as a common carrier of HHG, as defined in G.S. 62-3(7), by engaging in intrastate commerce as set forth in G.S. 62-3(15);

(b) Why First Class Move should not be found to have performed an intrastate transportation of HHG for compensation in North Carolina without a certificate of exemption, as required in G.S. 62-261(8) and Commission Rule R2-8.1, by performing a move of HHG from Morrisville, North Carolina to Burlington, North Carolina, for the Complainant on June 15, 2011; and

(c) Why First Class Move, for its actions, should not be subject to sanctions or penalties provided by G.S. 62-310(a), recoverable pursuant to G.S. 62-312, and/or have its license plates revoked/suspended pursuant to G.S. 62-278(a).[1]

The Commission ordered the Public Staff to participate in the hearing on behalf of the using and consuming public and to prosecute the show cause proceeding. The hearing was scheduled for September 5, 2012.

On August 15, 2012, the Complainant filed a letter with the Commission requesting an alternate date for the Show Cause Hearing. The same day, the Commission issued an Order Rescheduling Show Cause Hearing from September 5, 2012, to September 13, 2012.

On September 11, 2012, the Public Staff filed a Motion for Continuance in the hearing.

[1] G.S. 62-278(a) authorizes the revocation and removal of the license plates from the vehicles of any carrier of persons or household goods by motor vehicle for compensation for willful violation of any provision of Chapter 62, or for the willful violation of any lawful rule or regulation made and promulgated by the Utilities Commission.

On September 12, 2012, the Commission issued an Order Rescheduling Hearing from September 13, 2012, to October 4, 2012.

On October 4, 2012, the matter came on for hearing as scheduled. The Complainant appeared *pro se* and testified. The Public Staff presented testimony from Cynthia K. Smith, Rate Specialist with the Public Staff Transportation Rates Division. The Respondent also appeared *pro se*.

At the conclusion of the hearing, the record was held open for two weeks, until October 18, 2012, for the Complainant to submit copies of the payments sent to her by the Respondent. Proposed Orders from the parties were requested to be filed in the record thirty (30) days after the release of the hearing transcript.

On November 16, 2012, the Commission issued an Order Granting Oral Request for Extension of Time to file proposed orders from November 12, 2012, until December 3, 2012.

On December 3, 2012, the Commission issued an Order Granting a Further Extension of Time from December 3, 2012, until December 7, 2012.

On December 4, 2012, the Public Staff filed a Verified Motion requesting that the Hearing be reopened and that a Show Cause Proceeding be instituted to determine whether the Respondent should be found to have perjured himself with regard to his sworn testimony at the October 4, 2012 hearing.

On January 2, 2013, the Commission issued an Order Serving Public Staff Motion to Reopen Hearing and Extending Time to File Proposed Orders from December 7, 2012, until January 18, 2013. The Respondent was requested to file his response to the Public Staff's Motion by January 14, 2013.

On January 18, 2013, the Public Staff filed its Proposed Order in the docket.

Based on the foregoing, the evidence provided at the hearing, and the entire record in this matter, the Hearing Examiner makes the following

FINDINGS OF FACT

1. The Commission has jurisdiction over public utilities, including those engaged in the intrastate transportation of household goods for compensation in North Carolina, as defined by G.S. 62-3(7) and (15).

2. The Respondent acted as a de facto public utility by holding itself out as a common carrier of household goods, as defined in G.S. 62-3(7), by engaging in intrastate commerce as set forth in G.S. 62-3(15). Lawrence Eugene Hinnant, III, is the owner and operator of First Class Move.

3. The Complainant found the Respondent's advertisement for moving services on the internet. She called the contact telephone number and spoke with the Respondent about his services. The Respondent informed the Complainant about the history of his company and the rates he charges. Based on her conversation with the Respondent, the Complainant eventually hired him to move her in June 2011.

4. On June 15, 2011, prior to obtaining a certificate, the Respondent performed a move of the Complainant's household goods between Morrisville, North Carolina and Burlington, North Carolina. The Respondent initially quoted $395 to the Complainant for the move. The morning after the move, the Complainant discovered that her 50 inch Samsung HDTV had been damaged and sought compensation from the Respondent.

5. The Respondent denied liability for damage to the Complainant's television, but offered her a payment of $900.00 to resolve the matter. The Complainant never received any payment from the Respondent and attempted to pursue her damage claim in the Wake County Small Claims Court.

6. The Complainant's efforts to pursue her damage claim in Small Claims Court were unsuccessful due to the difficulty serving the complaint. She contacted the Public Staff for assistance. The Public Staff's Transportation Rates Division was also unsuccessful in getting the Respondent to resolve the damage claim. The Complainant was advised by the Public Staff to file a formal complaint with the Commission.

7. On September 9, 2011, in Docket No. T-4445, Sub 0, the Respondent was granted certificate No. C-2523 by the Commission to transport household goods in the state of North Carolina.

8. The Respondent is properly before the Commission, pursuant to Commission Rule R1-4(3).

9. On October 3, 2012, the Respondent sent to the Public Staff by electronic mail (e-mail) photocopies of two money orders, each in the amount of $500.00 and payable to the Complainant. One of these money orders bore the number R204162459590, and the other bore the number R204162459591.

10. At the hearing in this docket, the Respondent gave sworn testimony acknowledging two photocopies of money orders (Hinnant Exhibit #1 and Hinnant Exhibit #2) to be the photocopies he had sent to the Public Staff the previous day. The Respondent also testified that he had mailed the two money orders to the Complainant.

11. At the conclusion of the hearing, the record was held open for two weeks, until October 18, 2012, in order to allow time for the Complainant to receive the money order payments sent to her by the Respondent and then to notify the Commission.

12. Contrary to the Respondent's October 3, 2012 e-mails to the Public Staff and his sworn testimony at the October 4, 2012 hearing, money order numbered R204162459591 never existed and money order numbered R204162459590 was never mailed to the Complainant but was cashed by the Respondent himself.

13. During its investigation, the Public Staff requested and received from MoneyGram, the money order vendor, a copy of a cashed money order bearing the number R204162459590. This money order was made payable to the Respondent and was cashed by him on November 9, 2012. The Public Staff also requested from MoneyGram a copy of cashed money numbered R204162459591, but received only a second copy of cashed money order numbered R204162459590.

14. The Public Staff's inability to obtain a copy of cashed money order numbered R204162459591, together with a comparison of the photocopies of money orders sent by the Respondent to the Public Staff the day before the hearing, indicates that the photocopy of purported money order numbered R204162459591 is an electronically altered photocopy of money order numbered R204162459590 rather than a photocopy of a separate money order.

15. The Complainant received no payment from the Respondent for damage to her television resulting from the June 15, 2011 move and there is nothing in the Commission's records to indicate that she has received payment since that date.

16. The Commission does not have jurisdiction to order the Respondent to pay the Complainant for damages which she alleges were caused by the Respondent.

17. On December 4, 2012, the Public Staff filed a Verified Motion requesting that the Hearing be Reopened and that a show cause proceeding be instituted to determine whether the Respondent should be found to have perjured himself with regard to his sworn testimony at the October 4, 2012, hearing. The Public Staff also served a copy of its Motion on the Respondent at the address he requested to be used.

18. On December 14, 2012, a Recommended Order was issued in Docket No. T-4445, Sub 6, revoking and cancelling certificate No. C-2523, for the failure of the Respondent to maintain on file with the North Carolina Division of Motor Vehicles evidence of cargo insurance coverage as required by G.S. 62-268. The Order became final on January 1, 2013. A copy of the order was served on the Respondent by certified mail at Suite 112, 5608 Spring Court, Raleigh, North Carolina, but was returned as undeliverable.

19. On December 28, 2012, the Commission issued an Order in Docket Nos. T-100, Sub 87, and T-4445, Sub 7, suspending certificate No. C-2523, for the failure of the Respondent to file its 2011 annual report with the Commission as required by G.S. 62-36 and Commission Rules R1-32 and R2-48. These orders were served on the Respondent by certified mail at Suite 112, 5608 Spring Court, Raleigh, North Carolina, but were returned as undeliverable.

20. On January 3, 2013, the Commission issued an Order Serving Public Staff's Motion to Reopen Hearing. The Respondent was given until January 14, 2013, to file a response.

21. As of January 14, 2013, the Respondent had not filed a response to the Commission's Order Serving Public Staff's Motion to Reopen Hearing.

DISCUSSION OF EVIDENCE

I. The Respondent moved the Complainant's household goods on June 15, 2011, from Morrisville, North Carolina to Burlington, North Carolina.

The Complainant's testimony in this docket is uncontroverted. She testified that she planned a move from Morrisville, North Carolina to Burlington, North Carolina, in June of 2011. While researching moving companies, she came across the Respondent's website. The website was an advertisement for the Respondent's moving services. She further testified that she contacted the Respondent by telephone. The Respondent informed the Complainant that his company is a local business, has been in business for about seven years, is fully insured, and has never had any claims filed against him. The Complainant further testified that she received a price quote from the Respondent of $395.00.

Based on the Respondent's representations on being a reputable mover, the Complainant hired the Respondent and scheduled the move for Wednesday, June 15, 2011. On the moving date, two of the Respondent's workers arrived at the Complainant's residence, loaded her household goods, and moved them from Morrisville to Burlington in a five-hour move. At the end of the move, the Complainant paid the Respondent $395.00 in cash. The Complainant did not obtain a receipt of her payment.[1] At the hearing on October 4, 2012, the Respondent took the stand, but did not dispute the Complainant's testimony that the Respondent performed the move in question.

II. The Respondent damaged the Complainant's television while moving her household goods on June 15, 2011.

During the move from Morrisville, North Carolina to Burlington, North Carolina, the Respondent damaged the Complainant's 50 inch Samsung HDTV. The Complainant testified that as time was running out toward the end of the move, the Respondent's workers left the television leaning against a couch downstairs instead of placing it on the television stand. The Complainant stated that she did not notice the damage to the television until the next day. As she and her fiancé finished cleaning up downstairs and were putting the television on the stand, they discovered a scratch across the top edge of the television. According to the Complainant, there was no scratch on the television prior to the move. When she turned the television on, she could only hear sound but see no picture. The Complainant called the Respondent immediately and told him about the damage to her television.

The Complainant further testified that the Respondent informed her that he would contact his insurance company about the television and call her back later that day, which was a Thursday, but she never got a call back from him. The Complainant then called the Respondent the next day, Friday, and sent him a text message to which he replied saying he had contacted his insurance company and would call her back on Monday. When the Complainant did not hear from the Respondent on Monday, she sent him a second text message. The Respondent returned her message that day and for the first time, he denied that his movers damaged her television.

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[1] The Complainant had to pay the Respondent an additional $40.00 to pick up a desk she had purchased before the move.

As a result of the Respondent's denial of responsibility for the television, the Complainant found the Better Business Bureau website, which listed the Public Staff –North Carolina Utilities Commission (Public Staff) as a resource. The Complainant contacted the Public Staff and spoke with Public Staff witness Cynthia Smith of the Transportation Rates Division.

The Complainant testified that the Respondent initially agreed to pay her $900.00 for the damaged television but she never received anything from him. Once she realized that the Respondent would not pay her, she decided to bring an action against the Respondent in Wake County Small Claims Court. However, this proved to be a difficult task because she had problems providing the Respondent with notice of the summons.

The Complainant attempted to serve the Respondent at - 6013 Dixon Drive, Raleigh, North Carolina. She had obtained the address through a Google search, but the address was incorrect and the Respondent never received the summons. The Complainant then attempted to have him served at a second address - 618 Pine Ridge Place, which she obtained from the Commission. When she appeared in court on August 30, 2011, she learned that the Respondent still had not received the summons. She was informed by the Sheriff, that an attempt was made to serve the Respondent, but he was out of town and would not return in time for the court date. The Complainant then attempted to have the Respondent served with notice a second time at the address but learned that he no longer lived at the address. Due to the Complainant's inability to have the Respondent properly served, she decided to discontinue her efforts against him in Small Claims Court. At the conclusion of her testimony, the Complainant informed the Commission that she would be satisfied if the Respondent paid her the $900.00 which he initially offered to her and that the Commission fines him.

Witness Smith testified that she first learned of the Respondent through another complaint she received in September of 2010. This was her first contact with the Respondent. At that time, she informed him of the requirements to operate legally in North Carolina. As a result of their conversation, the Respondent filed an application for a certificate from the Commission on September 22, 2010.

When the Complainant called the Public Staff in June of 2011, witness Smith contacted the Respondent in an attempt to resolve the damage claim. She emphasized to the Respondent the need for the parties to come to a resolution in this matter and suggested some sort of payment arrangement. Despite her efforts, witness Smith was unsuccessful in convincing him to resolve the damage claim. Thereafter, witness Smith advised the Complainant of her option to file a formal complaint against the Respondent with the Commission.

Witness Smith also testified that at no time during their conversations, did the Respondent deny moving the Complainant's household goods on June 15, 2011. She further noted that the Respondent knew he was not allowed to move until he obtained his certificate from the Commission. She testified that the Commission's records show that the Respondent was not issued a certificate until September 9, 2011. She also testified that the Respondent performed the move several months before he received his certificate. As a result of this fact, she recommended that the Commission assess the Respondent a fine of $500.00 for operating without a certificate.

III. The Respondent testified at the hearing on October 4, 2012, that he sent the sum of $1,000.00 to the Complainant to satisfy her damage claim against him.

At the hearing, the Respondent testified that he sent two money orders to the Complainant in the amount of $500 each. He stated that the money orders were sent to the Complainant by U.S. mail a few days prior to the hearing.

Witness Smith testified that the Respondent e-mailed her copies of the two money orders a day before the hearing. The copies of the two money orders were identified as Hinnant Exhibit #I and Hinnant Exhibit #2, with numbers ending in 91 and 90. According to the photos, the money orders were payable to the Complainant in the amount of $500 each for damage to the Complainant's television. These money orders were purportedly mailed to her Burlington address. At the conclusion of the hearing, the record was held open for two weeks, until October 18, 2012, so that the Complainant could inform the Commission that she received the payments that were sent to her by the Respondent.

The Complainant did not receive the payments by October 18, 2012. Based on this information, the Public Staff initiated an investigated into the Respondent's claim that he sent the money orders to the Complainant. During its investigation, the Public Staff contacted MoneyGram, the money order vendor, and received a copy of a cashed money order bearing the number R204162459590. This money order was made payable to the Respondent and was cashed by him on November 9, 2012. The Public Staff also requested from MoneyGram a copy of cashed money order numbered R204162459591, but received only a second copy of cashed money order numbered R204162459590. The Public Staff's inability to obtain a copy of cashed money order numbered R204162459591, together with a comparison of the photocopies of money orders sent by the Respondent to the Public Staff the day before the hearing, indicates that the photocopy of purported money order numbered R204162459591 is an electronically altered photocopy of money order numbered R204162459590 rather than a photocopy of a separate money order.

At the conclusion of its investigation, the Public Staff determined that money order numbered R204162459591 never existed and money order numbered R204162459590 was never mailed to the Complainant but was cashed by the Respondent himself. As a result of these findings, the Public Staff filed a verified motion with the Commission, requesting that the hearing be reopened and that a show cause proceeding be instituted to determine whether the Respondent should be found to have perjured himself with regard to his sworn testimony at the October 4, 2012 hearing.

The Public Staff's motion was served on the Respondent for a response. However, the Respondent did not make a filing in response to the allegations made by the Public Staff.

CONCLUSIONS

> The status of an entity as a public utility does not depend upon whether it has obtained operating authority from the Commission, but rather upon whether it is in fact operating a business defined as a public utility by the General Statutes. *State ex. rel. Utilities Commission v. Carolina Telephone and Telegraph Co.*, 267 N.C. 257 (1966); *State ex. rel. Utilities Commission v. Mackie*, 79 N.C. App. 19 (1986), *modified and aff'd*, 318 N.C. 686 (1987).[1]

The Commission has previously found jurisdiction over common carriers of household goods that operate in the state without first being issued a certificate.[2] The Hearing Examiner also finds that jurisdiction exists over the Respondent in this docket. The uncontested evidence in this proceeding shows that the Respondent acted as a *de facto* public utility by holding itself out as a common carrier of household goods and engaging in the intrastate transportation of household goods for compensation in North Carolina by performing a move for the Complainant on June 15, 2011, from Morrisville, North Carolina to Burlington, North Carolina, without a certificate of exemption as required by G.S. 62-261(8) and Commission Rule R2-8.1. The Respondent performed the move in question, three months prior to being granted a certificate from the Commission.[3]

The uncontested evidence also shows that the Complainant discovered damage to her television after the move. Specifically, there was a scratch across the top edge of the television and when she turned the television on there was no picture, only sound. It was the Respondent's movers who moved the television and left it leaning against a couch in the Complainant's apartment. Although the Respondent denies liability for the damage, he offered compensation of $900.00 to the Complainant to resolve the matter. However, the Respondent has failed to make good on his offer of compensation.

Since the Commission lacks any power to render a judgment for compensatory damages, which includes the payment of money,[4] the Hearing Examiner finds and concludes that this complaint should be dismissed to the extent it seeks money damages. Nevertheless, the Commission does have a duty to enforce the statutes and rules governing the movement of household goods in intrastate commerce in North Carolina and to impose appropriate sanctions for violation of those provisions.

While the Public Staff recommended a penalty of only $500.00, in light of the Respondent's evasiveness when dealing with the Complainant and the Public Staff regarding the settlement of the damage claim, the Hearing Examiner finds and concludes that the Respondent should be assessed a penalty of $1,000 pursuant to G.S. 62-310(a), recoverable pursuant to

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[1] *citing N.C.U.C. Dkt. No. T-4445, SUB 2*, (September 26, 2012).

[2] *Id.*

[3] *N.C.U.C Dkt. No. T-4445, SUB 0*, (September 9, 2011) (The Respondent was granted certificate No. C-2523 for the transportation of household goods in intrastate commerce in North Carolina.).

[4] *State ex rel. N.C. Corporation Commission v. Southern Railway*, 147 N.C. 483, 61 S.E. 271 (1908).

G.S. 62-312, for willful violation of G.S. 62-261(8) and Commission Rule R2-8.1. In light of developments subsequent to the hearing, the Hearing Examiner further finds and concludes that the Respondent should also have his license plates[1] revoked and removed by the Division of Motor Vehicles for a period of 30 days pursuant to G.S. 62-278 for willful violation of G.S. 62-261(8) and Commission Rule R2-8.1.

At the October 4, 2012 hearing in this matter, the Respondent made statements under oath that he had purchased money orders bearing numbers R204162459590 and R204162459591, each in the amount of $500 and each payable to the Complainant. The record shows that these statements were material to the complaint that gave rise to this proceeding and were made knowingly, willingly, and designedly and were demonstrably false, thus constituting perjury under North Carolina law.[2] The Hearing Examiner, therefore, finds and concludes that the Respondent has perjured himself and is subject to punishment as a Class F felon pursuant to G.S. 14-209, should the Commission decide to refer the matter to the Wake County District Attorney for prosecution. In light of the totality of the circumstances, including the other sanctions imposed by this Order, the Hearing Examiner concludes this decision should be deferred for a period of 90 days.

Finally, the Hearing Examiner takes judicial notice of the following dockets involving the Respondent: Docket No. T-4445, Sub 0 – Application for Certificate of Exemption[3]; Docket No. T-4445, Sub 6 – Failure to Maintain Cargo Insurance[4]; and T-4445, Sub 7 – Failure to File Annual Report[5]. These dockets take action against the Respondent and levy some form of administrative sanction/penalty with regards to its certificate. The Hearing Examiner sees no reason why additional sanction and/or penalties should not be levied against the Respondent in this separate complaint proceeding. Accordingly, the Hearing Examiner is taking appropriate action against the Respondent for its willful disregard of North Carolina law and the Commission's Rules.

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[1] *See N.C.U.C. Dkt. T-4445, SUB 2*, (September 26, 2012) (The Commission found that First Class Move operates two (2) motor vehicles with license plates issued by the North Carolina Division of Motor Vehicles (DMV), a 19996 Freightliner FL70 and a 1997 International 4700. First Class Move also owns another 1997 International that has not been issued license plates by the DMV.).

[2] *State v. Smith*, 230 N.C. 198, 52 S.E.2d 348 (1949).

[3] First Class Move was granted a certificate (C-2523) by the Commission on September 9, 2011.

[4] The Commission issued an Order on December 14, 2012, revoking First Class Move's certificate for failure to maintain cargo insurance.

[5] The Commission issued an Order on December 28, 2012, suspending First Class Move's certificate for failure to file his annual report.

IT IS, THEREFORE, ORDERED as follows:

1. That the complaint filed by Dr. Crystal Simpson Tyson seeking compensation for damage to her 50 inch Samsung HDTV is dismissed.

2. That pursuant to G.S. 62-310(a), Lawrence Eugene Hinnant, III, d/b/a First Class Move, shall remit in United States currency or certified funds to the Commission (made payable to the North Carolina Department of Commerce/Utilities Commission) a penalty in the amount of $1,000, as one payment or in 12 equal monthly installments to the Office of the Chief Clerk, commencing 30 days following the issuance of this Order and every subsequent 30 days thereafter until the $1,000 is paid in full, for operating as a *de facto* public utility by holding himself out as a common carrier of household goods by engaging in intrastate commerce as set forth in G.S. 62-3(15), and by performing intrastate transportation of household goods for compensation in North Carolina, without a certificate of exemption, as required by G.S. 62-261(8) and Commission Rule R2-8.1.

3. That pursuant to G.S. 62-278, the license plates shall be revoked and removed from the vehicles of Lawrence Eugene Hinnant, III, d/b/a First Class Move, for a period of 30 days for willful violation of G.S. 62-261(8) and Commission Rule R2-8.1.

4. That a decision regarding whether to pursue perjury charges against the Respondent is deferred for a period of 90 days from the date of this Order.

5. That this Order shall be served on the Parties by United States certified mail, return receipt requested.

ISSUED BY ORDER OF THE COMMISSION.
This the 10th day of May, 2013.

NORTH CAROLINA UTILITIES COMMISSION

Paige J. Morris, Deputy Clerk

Bh051013.02

DOCKET NO. W-1034, SUB 6

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Water Resources, Inc., 5970 Fairview Road, Suite 710, Charlotte, North Carolina 28210, for a Certificate of Public Convenience and Necessity for Water Utility Service in River Walk Subdivision, in Mecklenburg County, North Carolina, and for Approval of Rates	)))))))	ORDER RULING ON EXCEPTIONS

BY THE COMMISSION: On January 18, 2011, Water Resources, Inc. (WRI), filed an application for a certificate of public convenience and necessity (CPCN) and to establish rates for providing water utility service in the River Walk subdivision (River Walk) in Mecklenburg County, North Carolina. Hearings were held on September 29, 2011, in Gastonia, North Carolina and on November 15, 2011, in Raleigh, North Carolina.

On November 15, 2011, WRl and the Public Staff filed an Agreement and Partial Stipulation of Settlement (Stipulation) resolving all issues in this proceeding, with the exception of a single disputed issue related to WRI's right to recover the capital cost of utility system through WRI's proposed connection fee from all prospective customers, including residents of River Walk that had previously been connected to the River Walk water system. The Stipulation presented this disputed issue to the Hearing Examiner for decision as a question of law.

On January 27, 2012, the Hearing Examiner issued a Recommended Order Granting Certificate of Public Convenience and Necessity, Approving Rates, Requiring Improvements, and Requiring Customer Notice. The Recommended Order, among other things, granted WRl a CPCN to provide water utility service in River Walk; approved the rates and charges agreed to in the Stipulation; and held that the $685 connection fee should only be recovered from new customers connecting to the River Walk water system in the future, and should not be recovered from currently connected users of the water system.

On February 13, 2012, Water Resources, Inc. (WRI), filed Exceptions to the Recommended Order in which it specifically identified four exceptions to the Recommended Order regarding the Hearing Examiner’s decision that the connection fee should only be recovered from new customers connecting to the River Walk water system. WRI did not, however, request oral argument in order to be heard on the exceptions. In the Exceptions, the WRI requested that it be allowed to implement the rates and charges approved by the Hearing Examiner as reflected in Appendix B to the Recommended Order for all service rendered on or after February 1, 2012, which was allowed nunc pro tunc by Order issued February 22, 2012.

After carefully considering the pleadings, the Recommended Order and the entire record in this matter, the Commission overrules in part and sustains in part WRI’s exceptions. The Commission determines that the Recommended Order is in error in disallowing recovery of 27 connection fees based on the doctrine of retroactive ratemaking. The Commission upholds the determination in the Recommended Order on the contested connection fee issue on the basis of waiver as subsequently addressed herein. The Commission, however, modifies the Recommended Order to permit WRI to recover through depreciation expense a portion of the $18,495 in purchase price disallowed by the Recommended Order without a finding of imprudence or unreasonableness.

Connection fees constitute customer-supplied capital or a contribution in aid of construction (CIAC). On the utility's books of account under the Uniform System of Accounts, CIAC is an offset to plant in service or an offset to rate base. Pursuant to G.S. 62-133, a utility is provided with the opportunity to recover its adjusted test year expenses and earn a return on its rate base. The doctrine of retroactive ratemaking precludes a company from collecting revenues to compensate for past under-recoveries of expenses incurred in providing service in past periods, the theory being that rates are established to recover a representative level of annual expense, based upon an adjusted test-period level of operations. Therefore, unless a company timely requests and receives Commission approval for deferral and amortization of previously incurred expenses or the Commission provides for such treatment on its own motion – for example, in the context of a general rate case – the company is precluded, by the doctrine of retroactive ratemaking, from recovering previously incurred expenses prospectively.

The doctrine of retroactive ratemaking does not preclude recovery of capital costs (or offsets to capital costs) incurred by the utility prior to the test period. The recovery of the total cost of a capital item is distinguished from the annual amortization or depreciation of the cost, the latter being deemed an expense item, which can be lost under the doctrine of retroactive ratemaking. The utility earns a return on end-of-period rate base, and the fact that a capital item was added or deleted prior to the test period does not prevent its inclusion in the determination of rate base in a general rate case proceeding. Indeed, many of the capital costs authorized for recovery in this case were incurred before the 2010 test period. As connection fees are capital cost offsets, the doctrine of retroactive ratemaking is not the appropriate ratemaking principle against which the costs at issue between the parties is appropriately assessed in this proceeding.

Another reason for this conclusion is that at the time WRI connected the residences of the 27 consumers in question to its water system, WRI had not yet obtained a CPCN and was not authorized to charge rates or enjoy the benefits of a public utility. Had WRI collected usage charges or connection fees prior to obtaining authorization to do so, the charges would have been refundable. As any charges could have been refundable as being ultra vires, it is not appropriate to judge recoverability of the 27 connection fees at issue against the doctrine of retroactive ratemaking. That doctrine assumes that the provider that assesses the charges at issue is a public utility when the charges are assessed, not an unlicensed provider operating without authority and providing service without charge.

As indicated above, connection fees, while capital in nature as opposed to recurring annual expenses, are offsets to rate base and therefore beneficial to the general body of the utility's rate payers. Connection fees reduce rate base and therefore result in lower commodity rates than would be otherwise. For operating ratio companies, connection fees reduce the annual level of depreciation expense recoverable through rates. Consequently the Commission, all other factors remaining equal, should encourage the collection of connection fees.

Another distinguishing feature of connection fees, however, is that, when collected from the ultimate consumer, the fees must be tariffed, or collected based upon a before the fact determination of reasonableness by the Commission.

Although the Commission determines that the Recommended Order erroneously determined the issue contested by the parties on the basis of retroactive ratemaking, it does not follow that the Commission should sustain WRI's exceptions. A second justification for prohibiting WRI from recovering the 27 connection fees addressed in the Recommended Order is waiver. Waiver is a mixed question of both fact and law. In this case, due to WRI's failure to obtain approval prior to making the physical connection to the 27 residences in question, the before the fact determination of reasonableness has not been made. Consequently, WRI faced a greater burden of proof and of persuasion than would otherwise have been the case to demonstrate why it had not waived its right to collect the 27 connection fees. Due to the significant factual and equitable questions raised by WRI's request to recover, after interconnection, connection fees from the 27 consumers, the Commission finds insufficient evidence and justification on the record to sustain WRI's exceptions that would permit it to assess ex post facto the 27 connection fees at this time. Insufficient evidence exists to justify an order permitting new charges for connections to the system accomplished in the past before WRI possessed a CPCN. In order to appropriately resolve this issue, it would have been necessary for WRI to address issues such as whether or not costs of connection were recovered through the cost of the lot or residence and whether the requested fee is set at a reasonable level. The record contains no evidence as to whether the present owners of the 27 residences were the owners when the connections were made. No evidence exists as to the understanding of WRI or of those whose residences were connected and on what facts their understanding was based.

Although the Public Staff and WRI have stipulated that the cost of connection for connections not yet made is $685, the Public Staff contests charging any connection fees to the 27 customers already connected. The $685 is simply the quotient from dividing the $50,000 purchase price by the 73 lots comprising the subdivision at full build out. Therefore, the Stipulation is not binding upon the parties with respect to the 27 connections, and WRI failed to meet its burden of proof or persuasion on this issue.

Although unwilling to sustain WRI's exceptions as phrased, the Commission acknowledges that WRI has demonstrated that a compelling case exists to support a determination that the Recommended Order contains inconsistent and inequitable findings and conclusions detrimental to WRI. On the one hand, in Finding of Fact No. 19, the Recommended Order prevents WRI from recovering connection fees from the 27 customers previously connected, depriving WRI from recovering $18,495 of its $50,000 purchase price. On the other hand, in Finding of Fact No. 12, the Recommended Order determines that "reasonable acquisition costs of utility plant are appropriately recoverable from customers, and that a connection fee is a reasonable approach to recovering this capital cost." These findings of fact are inconsistent and irreconcilable. The Recommended Order is based on a determination that the $50,000 purchase price is completely recoverable through connection fees, yet $18,495 of the $50,000 is not recoverable because 27 customers cannot be charged the connection fee. The Recommended Order contains no finding that the $50,000 purchase price is unreasonable or imprudent and indeed implies just the opposite. Yet, the Recommended Order disallows $18,495 of the $50,000. The

Recommended Order, in effect, attributes to WRI $18,495 in connection fees the order prohibits WRI from collecting.

While it may be permissible and appropriate to prevent WRI from assessing connection fees to the 27 residents, no justification exists on the record in this case for disallowing altogether $18,495 of the purchase price and attributing to WRI $18,495 it cannot collect. After all, WRI has provided free water service to 27 customers up until now, some for nearly 10 years. Likewise, WRI has been attributed accumulated depreciation for years before it will obtain its CPCN, thus reducing its recoverable investment and the level of its annual depreciation expense. Moreover, the developer has incurred $198,992 in water system costs for which customers will not be responsible. WRI's alleged lack of diligence in failing to obtain a CPCN before connecting the 27 customers may be justification for requiring it to forego the $18,495 through assessment of connection fees, but not justification for preventing it from recovering some portion of the $18,495 through rates and charges in any manner whatsoever.

To rectify this inconsistency and inequitable result, the Commission determines that the fairest remedy is to amend Finding of Fact No. 12 to permit WRI to include the $18,495 in its rate base, or, to the extent rates are still to be established on an operating ratio basis, to allow WRI to recover the $18,495 through usage rates as depreciation expense over time from all of its customers.[1] It appears that WRI has stipulated to levels of accumulated depreciation and depreciation expense on the theory that depreciation for ratemaking purposes should begin with the date the asset in question was placed in service irrespective of the date WRI's CPCN is obtained. Consistent with this approach, the Commission requires that the $18,495 should be treated as a cost of the water system placed in service in 2002. This determination is beneficial to ratepayers because it assumes 10 years of depreciation has been recovered from ratepayers when in fact it has not. The Commission has utilized a 30-year service life consistent with schedules attached to the Stipulation. The Commission has made a preliminary determination as to the impact on the base charge and usage charge that would result to implement the modification to the Recommended Order required herein based on assumptions the Commission anticipates the parties would employ. See Appendix A. The Commission remands this docket to the Hearing Examiner with instructions that the parties be permitted to accept the rates set forth in Appendix A, or if they are unwilling to do so that the record be reopened to take additional evidence necessary to implement this Order.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 15th day of July, 2013.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

Commissioners ToNola D. Brown-Bland and Jerry C. Dockham did not participate.
Bh071513.02

[1] The other alternative would be to increase the connection fee to the yet to be connected 46 customers. This alternative inequitably shifts too much of the cost to these customers.

APPENDIX A

Monthly Rates per the Agreement and Partial Stipulation of Settlement filed on November 15, 2011 adopted in Recommended Order:

Base charge, zero usage	$ 38.30
Usage charge, per 1,000 gallons	$ 9.57
Average monthly bill (using 6,000 gallons)	$ 95.72
Annual Revenue Requirement	$31,025

Monthly Rates including $18,495 (27 x $685) rate base investment depreciated for 8.5 years based on 30-year amortization period in accordance with Order Ruling on Exceptions:

Base charge, zero usage	$ 39.24
Usage charge, per 1,000 gallons	$ 9.81
Average monthly bill (using 6,000 gallons)	$ 98.10
Annual Revenue Requirement	$31,786

Assumptions: 50% debt, 50% equity capital structure; a 5.00% cost of debt; and an 8.00% overall return on rate base using the Public Staff's Excel files for the above-referenced docket. Consistent with the Public Staff's calculation, rates were designed using the assumption that 40% of the revenue requirement is applied to the base charge and 60% of the revenue requirement is applied to the usage charge.

DOCKET NO. W-1034, SUB 6

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Water Resources, Inc.,	)	
5970 Fairview Road, Suite 710, Charlotte,	)	RECOMMENDED ORDER
North Carolina 28210, for a Certificate of	)	IMPLEMENTING ORDER RULING
Public Convenience and Necessity for Water	)	ON EXCEPTIONS AND REQUIRING
Utility Service in River Walk Subdivision, in	)	CUSTOMER NOTICE
Mecklenburg County, North Carolina, and for	)	
Approval of Rates	)	

HEARD IN: Community Room, Gastonia Police Department, 200 East Long Avenue, Gastonia, North Carolina, on September 29, 2011, at 7:00 p.m.

Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on November 15, 2011, at 9:00 a.m.

BEFORE: Ronald D. Brown, Hearing Examiner

APPEARANCES:

For Water Resources, Inc.:

E. Brett Breitschwerdt, McGuireWoods, LLP, Post Office Box 27507, Raleigh, North Carolina 27601

For the Using and Consuming Public:

Robert S. Gillam, Staff Attorney, Public Staff - North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BROWN, HEARING EXAMINER: On January 18, 2011, Water Resources, Inc. (WRI) filed an application for a certificate of public convenience and necessity (CPCN) to provide water utility service in the River Walk Subdivision (River Walk) in Mecklenburg County, North Carolina. Hearings were held on September 29, 2011, in Gastonia, North Carolina, and on November 25, 2011, in Raleigh, North Carolina.

On January 27, 2012, the Hearing Examiner issued a Recommended Order Granting Certificate of Public Convenience and Necessity, Approving Rates, Requiring Improvements, and Requiring Customer Notice. On February 13, 2012, WRI filed Exceptions to the Recommended Order.

On July 15, 2013, the Commission issued an Order Ruling on Exceptions in which WRI was allowed to include $18,495 in its rate base, or, to the extent rates are still to be established on an operating ratio basis, to allow WRI to recover the $18,495 through usage rates as depreciation expense over time from all of its customers. The Commission made a determination that the effect on the rates of including this amount in the rate base would be as follows:

	Recommended Order Rates	New Rates
Base charge, zero usage	$38.30	$39.24
Usage charge, per 1,000 gallons	$ 9.57	$ 9.81

The Order Ruling on Exceptions remanded the matter back to the Hearing Examiner with instructions that the parties be permitted to accept the rates set forth above, or if they are unwilling to do so that the record be reopened to take additional evidence necessary to implement the Order Ruling on Exceptions.

On July 22, 2013, the Public Staff and WRI notified the Commission that it accepted the rates specified by the Commission, as noted above.

Based upon the foregoing, the Hearing Examiner concludes that the agreed to rates shall be adopted; that $18,495 shall be included in WRI's rate base; that the Ordering Paragraphs from the Recommended Order are still applicable; that a copy of this Order shall be mailed or hand delivered to all customers of WRI in River Walk Subdivision within 15 days of the date of this

Order; and that WRI shall submit to the Commission the attached Certificate of Service properly signed and notarized not later than 30 days after the date of this Order.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 12th day of _August_, 2013.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

rb080913.01

APPENDIX B
PAGE 1 OF 2

SCHEDULE OF RATES

for

WATER RESOURCES, INC.

for providing water utility service in

RIVER WALK SUBDIVISION

Mecklenburg County, North Carolina

Monthly Metered Water Utility Service Rates:

Base charge, zero usage	$ 39.24
Usage charge, per 1,000 gallons	$ 9.81

Connection Charge: (New Residential Connection Only)	$685.00
New Account Fee:	$ 40.00

Reconnection Charge:

If water service is cut off by utility for good cause:	$ 40.00
If water service cut off by utility at customer's request:	$ 40.00
Billing rates per hour for after hours, holidays, weekends	$ 40.00

If payment for water utility service is not received by the past-due date, a customer may, in addition to all past-due and current charges, have to pay late payment finance charges to avoid having water utility service disconnected.

To resume water utility service after discontinuance for good cause, a customer must pay the reconnection charge(s) discussed above, plus any delinquent water bill(s), including finance charges.

APPENDIX B
PAGE 2 OF 2

Returned Check Charge:	$25.00
Billing Frequency:	Shall be monthly for service in arrears
Bills Due:	On billing date
Bills Past Due:	15 days after billing date
Finance Charges for Late Payment:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after the billing date.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-1034, Sub 6, on this the 12th day of August, 2013.

CERTIFICATE OF SERVICE

I, ____, mailed with sufficient postage or hand delivered to all affected customers the attached Notice to Customers issued by the North Carolina Utilities Commission in Docket No. W-1034, Sub 6, and the Notice was mailed or hand delivered by the date specified in the Order.

This the _____ day of ____________________, 2013.

By: ______________________________________
Signature

____
Name of Utility Company

The above named Applicant, _________________________________, personally appeared before me this day and, being first duly sworn, says that the required Notice to Customers was mailed or hand delivered to all affected customers, as required by the Commission Order dated __________________ in Docket No. W-1034, Sub 6.

Witness my hand and notarial seal, this the ____ day of ______________, 2013.

____
Notary Public

____
Printed Name

(SEAL) My Commission Expires: ______________________________________
Date

DOCKET NO. W-1300, SUB 2

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Old North State Water Company, LLC, 1620 Chalks Road, Wake Forest, North Carolina 27587, Certificate of Public Convenience and Necessity, in Carolina Plantations Subdivision, Onslow County, North Carolina, and for Approval of Rates	)))))))	ORDER REQUIRING CUSTOMER NOTICE, APPROVING TEMPORARY OPERATING AUTHORITY AND INTERIM RATES

BY THE COMMISSION: On June 20, 2013, Old North State Water Company, LLC (ONSWC), filed an application seeking a certificate of public convenience and necessity for the sewer utility system in Carolina Plantations Subdivision in Onslow County, North Carolina, and approval of rates. The sewer system in Carolina Plantations serves 819 customers.

Carolina Plantations' sewer system was installed and is owned by Carolina Plantation Development Corporation (Developer), which has been providing the sewer service. The water service is provided by the Onslow Water and Sewer Authority.

The Division of Water Quality of the North Carolina Department of Environment and Natural Resources (DWQ) issued Permit No. WQ0033770 dated April 15, 2009, for the construction and operation of a 300,000 gallon per day wastewater high-rate infiltration and disposal facility at Carolina Plantations. Carolina Plantations' sewer system has experienced some DWQ permit compliance issues, and the Developer desires to transfer operations of the sewer system to a professionally operated, Commission regulated public utility as soon as reasonably possible.

ONSWC's application requested Commission approval of a sewer residential monthly flat rate of $45 per residential equivalent unit (REU). After the Public Staff's audit and following extensive discussions with the Public Staff, ONSWC amended its application to request residential and commercial monthly flat rates to $38 per REU. The Asset Purchase Agreement between the Developer and ONSWC dated May 31, 2013, states that ONSWC will pay Developer a purchase price of $500 per connection. ONSWC has not applied for a connection fee.

ONSWC has requested Commission approval of temporary operating authority and interim rates subject to refund if lesser rates are later approved by the Commission. ONSWC operates a sewer utility system serving the Majestic Oaks subdivision in Pender County pursuant to a certificate of public convenience and necessity issued by the Commission.

The Public Staff has recommended that ONWSC be required to post a $20,000 bond for Majestic Oaks Subdivision. ONWSC has filed the $20,000 bond recommended by the Public Staff.

The Public Staff stated that it believes that ONSWC has the technical, managerial, and financial capacity to provide sewer utility service to Carolina Plantations subdivision. The Public Staff recommended Commission approval of ONSWC's request for temporary operating authority and approval of interim sewer residential and commercial monthly flat rates of $38 per REU, subject to refund. Finally, the Public Staff recommended that ONSWC provide customer notice and that the notice state that the matter may be decided without a hearing if no significant protests are received within 30 days of delivery of customer notice

IT IS, THEREFORE, ORDERED as follows:

1. That the bond and surety in the amount of $20,000, filed in this proceeding as required by the Commission, is accepted and approved.

2. That Old North State Water Company, LLC, is hereby granted Temporary Operating Authority for a period of 12 months, effective on the date of this Order.

3. That Appendix A constitutes the Certificate of Authority for Temporary Operating Authority.

4. That interim sewer residential and commercial monthly flat rates of $38.00 per REU are approved, subject to refund should the Commission subsequently approve a lesser rate. Said interim rates are authorized to become effective for service rendered on and after the date of this Order.

5. That the Notice to Customers, attached hereto as Appendix B, be mailed with sufficient postage or hand delivered by ONSWC to all affected customers no later than two business days after the date of this Order.

6. That ONSWC shall submit to the Commission the attached Certificate of Service properly signed and notarized not later than 20 days from the date of this Order.

7. That ONSWC shall submit to the Commission the Undertaking, attached as Appendix C, executed by a member manager no later than two business days after the date of this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 30th day of December, 2013.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

WATER AND SEWER – CERTIFICATE

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

APPENDIX A

DOCKET NO. W-1300, SUB 2

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

OLD NORTH STATE WATER COMPANY, LLC

is granted

TEMPORARY OPERATING AUTHORITY

for providing sewer service

in

CAROLINA PLANTATIONS SUBDIVISION

Onslow County, North Carolina

subject to any orders, rules, regulations
and conditions now or hereafter lawfully made
by the North Carolina Utilities Commission.

ISSUED BY ORDER OF THE COMMISSION.
This the 30th day of _December_, 2013.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

APPENDIX B
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NOTICE TO CUSTOMERS
DOCKET NO. W-1300, SUB 2
BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

Notice is given that Old North State Water Company, LLC (ONSWC), filed an application with the Commission on June 20, 2013, seeking a Certificate of Public Convenience and Necessity for the sewer utility system in Carolina Plantations Subdivision in Onslow County, North Carolina, and approval of rates. ONSWC proposes to charge the rates as follows:

<u>Monthly Flat Rate Residential Sewer Service</u>:	$38.00
<u>Monthly Flat Rate Commercial Sewer Service</u>:	$38.00 per REU
<u>New Account Fee</u>:	$15.00
<u>Reconnection Charges</u>:	Actual cost
<u>Returned Check Fee</u>:	$25.00
<u>Bills Due</u>:	On billing date
<u>Bills Past Due</u>:	15 days after billing date
<u>Billing Frequency</u>:	Shall be monthly for service in arrears
<u>Finance Charges for Late Payment</u>:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date.

By Order dated December 19, 2013, the Commission approved temporary operating authority for ONSWC to assume operations of the Carolina Plantations sewer utility system and begin charging interim rates at the applied for residential sewer monthly flat rate of $38.00 and commercial sewer monthly flat rate of $38.00 per residential equivalent unit (REU).

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<u>PROCEDURE FOR PUBLIC HEARING</u>

At this time, no public hearing has been scheduled. <u>A hearing may be scheduled if significant protests are received from consumers within 30 days of the date of this notice</u>. Correspondence concerning the proposed rates, service problems, or the public hearing should be directed to the Public Staff.

The Public Staff is authorized by statute to represent consumers in proceedings before the Commission. Written statements/protests to the Public Staff should include any information which the writer wishes to be considered by the Public Staff in its investigation of the matter, and such statements should be addressed to Mr. Christopher J. Ayers, Executive Director, Public Staff, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326. Written statements can also be faxed to (919) 715-6704 or emailed to babette.mckemie@psncuc.nc.gov.

The Attorney General is also authorized by statute to represent consumers in proceedings before the Commission. Statements/protests to the Attorney General should be addressed to The

Honorable Roy Cooper, Attorney General, c/o Utilities Section, 9001 Mail Service Center, Raleigh, North Carolina 27699-9001.

Written statements are not evidence unless those persons submitting the statements appear at the public hearing and testify concerning the information contained in their written statements.

Persons desiring to present testimony concerning their opinion on this application, or on any service problems they may be experiencing, may appear at the public hearing and give such testimony.

Persons desiring to intervene in the matter as formal parties of record should file a petition under North Carolina Utilities Commission Rules R1-5 and R1-19 no later than 30 days after the date of this Order. Such motions should be filed with the North Carolina Utilities Commission, 4325 Mail Service Center, Raleigh, North Carolina 27699-4325.

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The details of the proposed rates have been filed with the North Carolina Utilities Commission. A copy of the application and all filings in this matter are available for review by the public at the Office of the Chief Clerk, 430 North Salisbury Street, Raleigh, North Carolina. Information regarding this proceeding can also be accessed from the Commission's website at www.ncuc.net.

This the 30th day of December, 2013.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

APPENDIX B

DOCKET NO. W-1300, SUB 2

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Application by Old North State Water Company, LLC, 1620 Chalks Road, Wake Forest, North Carolina 27587, Certificate of Public Convenience and Necessity, in Carolina Plantations Subdivision, Onslow County, North Carolina, and for Approval of Rates) UNDERTAKING

WATER AND SEWER – CERTIFICATE

NOW COMES Old North State Water Company, LLC, and files this Undertaking as follows:

Old North State Water Company, LLC, by and through its undersigned member manager, makes it written undertaking to the North Carolina Utilities Commission that it will refund to its customers any amount of the approved interim rate, plus 10% interest per annum, that may be finally determined by the Commission to be excessive and is required by Final Order of the Commission.

This the _____ day of _____________, 2013.

Old North State Water Company, LLC

By: ____________________________
Member Manager

CERTIFICATE OF SERVICE

I, ____, mailed with sufficient postage or hand delivered to all affected customers the attached Notice to Customers issued by the North Carolina Utilities Commission in Docket No. W-1300, Sub 2, and the Notice was mailed or hand delivered by the date specified in the Order.

This the _____ day of ____________________, 2013.

By: _____________________________________
Signature

____
Name of Utility Company

The above named Applicant, ________________________________, personally appeared before me this day and, being first duly sworn, says that the required Notice to Customers was mailed or hand delivered to all affected customers, as required by the Commission Order dated __________________ in Docket No. W-1300, Sub 2.

Witness my hand and notarial seal, this the ____ day of _____________, 2013.

____
Notary Public

____
Printed Name

(SEAL) My Commission Expires: _____________________________________
Date

DOCKET NO. W-386, SUB 18

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Holiday Island Property Owners Association, Inc., d/b/a Holiday Island Utility Company, 123 B Clubhouse Road, Hertford, North Carolina 27944, to Discontinue Water and Sewer Utility Services at Camp Holiday, Perquimans County, North Carolina	)	ORDER APPROVING TRANSFER TO OWNER EXEMPT

HEARD IN: Perquimans County Courthouse, Courtroom 1, 128 N. Church Street, Hertford, North Carolina, on Thursday, December 15, 2011, at 9:00 a.m.

Perquimans County Courthouse, Courtroom 1, 128 N. Church Street, Hertford, North Carolina, on Tuesday, January 31, 2012, at 10:00 a.m.

BEFORE: Commissioner William T. Culpepper, III, Presiding; and Commissioners Bryan E. Beatty and ToNola D. Brown-Bland

APPEARANCES:

For Holiday Island Property Owners Association, Inc., d/b/a Holiday Island Utility Company:

Steven J. Levitas, Kilpatrick, Townsend & Stockton, LLP, 4208 Six Forks Road, Suite 1400,Raleigh, North Carolina 27609

For Minzies Creek Village:

Lloyd C. (Clif) Smith, III, Pritchett & Burch, PLLC, Post Office Drawer 100, Windsor, North Carolina 27983

For the Using and Consuming Public:

William E. Grantmyre, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: On September 6, 2011, Holiday Island Property Owners Association, Inc., d/b/a Holiday Island Utility Company (HIPOA), filed an Application to Discontinue Water and Sewer Utility Services (Discontinuance Application) to the Camp Holiday service area located in Perquimans County, North Carolina, stating therein that there is no reasonable probability that HIPOA will be able to realize sufficient revenues from its customers to make the repairs and improvements to HIPOA's wastewater utility system which are required by the North Carolina Department of Environment and Natural Resources (NCDENR).

On October 3, 2011, the Commission issued an Order Scheduling Hearing and Requiring Public Notice for the Discontinuance Application. That Order scheduled a public hearing for December 15, 2011, in the Perquimans County Courthouse in Hertford, North Carolina.

On November 2, 2011, HIPOA prefiled the direct testimony and exhibits of its witnesses Elaine A. Mazur, HIPOA's Treasurer; David May, Aquifer Protection Regional Supervisor for the Washington Region of the Division of Water Quality of NCDENR (DWQ); and William G. Simmons, Professional Engineer.

On November 16, 2011, the Public Staff-North Carolina Utilities Commission (the Public Staff) prefiled the direct testimony of Babette McKemie, Utilities Engineer, Water Division; the direct testimony and exhibits of Laura D. Bradley, Staff Accountant, Accounting Division; and the Affidavit of Calvin C. Craig, III, Financial Analyst, Economic Research Division. Intervention and participation in this docket by the Public Staff is made and recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

On November 16, 2011, customers of HIPOA's wastewater utility system, an unincorporated nonprofit association named Minzies Creek Village, filed a Petition to Intervene. The Commission granted the Minzies Creek Village Petition to Intervene by Order dated November 22, 2011.

On December 2, 2011, HIPOA prefiled the rebuttal testimony and exhibits of its witness, Elaine A. Mazur.

On December 8, 2011, HIPOA filed a Motion to Stay Proceeding in which HIPOA requested the Commission stay until June 15, 2012, the discontinuance of water and wastewater utility service aspects of this proceeding in order to provide Minzies Creek Village the opportunity to form a sanitary district for the purpose of taking ownership of the HIPOA water and wastewater utility systems.

Also, on December 8, 2011, HIPOA filed a Petition for Emergency Assessment and Temporary Surcharge (Assessment Petition).

Pursuant to the Assessment Petition, HIPOA applied for an emergency assessment totaling $6,917 and a temporary surcharge totaling $8,100. HIPOA stated the emergency assessment is necessary to pay for past improvements and renovation costs to its wastewater utility system. HIPOA stated the temporary surcharge is necessary to generate funds to continue operating the system and create a reserve for maintenance and repair costs that might arise during the pendency of this proceeding. HIPOA proposed that each of its 90 customers should be assessed $25.62 per month and surcharged $30.00 per month for three months.

On December 8, 2011, the Public Staff filed Comments supporting the requested stay of the discontinuance proceeding and supporting the requested emergency assessment and temporary surcharge.

On December 12, 2011, Minzies Creek Village filed a Consent to Motion to Stay Proceeding citing its efforts to form a sanitary district.

On December 12, 2011, the Commission issued an Order Staying Evidentiary Hearing and Imposing Conditions. Said Order stayed the discontinuance evidentiary hearing until June 15, 2012, and required Minzies Creek Village to file progress reports with the Commission regarding the progress of the sanitary district formation.

On December 15, 2011, the first public hearing was held in Hertford, North Carolina, as scheduled. The following customers presented testimony: William Smith, Annie Gavin, Norman Morris, Jr., Peter Messina, Jr., Jeannie Thigpen, Jeanne Hecker, Frank Page, Melinda Sue Haugen, Clay Helm, David Stephenson, Jerry Butler, Christopher Colvin, James Finley, Chris Angelo, Richard Keller, and David Colvin. All of the 16 public witnesses that testified stated that they were opposed to closure of the wastewater treatment plant and supported the creation of a sanitary district.

On December 22, 2011, the Commission issued its Order Scheduling Public Hearing, which among other things, scheduled an evidentiary hearing on the Assessment Petition for January 31, 2012, in Hertford, North Carolina.

On January 20, 2012, the Public Staff filed the Assessment and Surcharge Testimony of its witness, Laura D. Bradley, Accountant, Public Staff Accounting Division.

On January 26, 2012, HIPOA filed the testimony and exhibits of its Secretary Barbara Bostwick.

On January 31, 2012, the second public hearing was held in Hertford, North Carolina, as scheduled. The following customers presented testimony: Cheryl Booten, Marshall Whisner, Kim Loveland, Jo Ann Kehr, Jeanne Hecker, Sheila Robertson, Melinda Haugen, and Clay Helm. The public witnesses generally testified that they were opposed to closure of the wastewater treatment plant, supported the creation of a sanitary district, and were concerned about accountability for funds paid to HIPOA. HIPOA presented the testimony of witness Barbara Bostwick. The Public Staff presented the testimony of witness Laura Bradley supporting the requested emergency assessment and temporary surcharge.

On March 2, 2012, the Public Staff and HIPOA filed a Joint Proposed Order on the Assessment Petition. On March 23, 2012, the Commission issued an Order Notifying Parties of Ex Parte Communication.

The Commission by Order dated April 4, 2012, approved emergency assessments totaling $6,917 to be collected from 83 wastewater customers in three monthly payments of $27.18, and the temporary surcharge totaling $6,932 to be collected from 83 wastewater customers in three monthly payments of $27.84. This Order stated in Ordering Paragraph No. 8 that should the water and wastewater systems in the future be transferred after Commission approval to a sanitary district formed by the customers, the remaining balance in the separate temporary surcharge account and the remaining balance in the Emergency Capital Improvement Assessment (ECIA) account established in 1992, if any after the loan repayment, shall be transferred to the sanitary district. This Order also required HIPOA to file monthly reports with the Commission and for the Public Staff to review each HIPOA monthly report and all supporting documentation, and report to the Commission should the Public Staff believe that there are inappropriate items in the report and/or documentation.

On February 14, 2013, HIPOA and the Minzies Creek Sanitary District filed a Joint Motion for Approval to Transfer to Owner Exempt (Transfer Motion) the water and wastewater utility systems serving Camp Holiday, Perquimans County, to the Minzies Creek Sanitary District. Attached to the Transfer Motion was an Agreement dated February 11, 2013 (Transfer Agreement), executed by HIPOA and the Minzies Creek Sanitary District, for the conveyance of the water and wastewater utility systems serving Camp Holiday.

On February 28, 2013, the Public Staff filed a Motion Supporting Approval of Transfer in which the Public Staff recommended the Commission approve the transfer to the Minzies Creek Sanitary District.

On March 28, 2013, the Public Staff, HIPOA and the Minzies Creek Sanitary District filed a Joint Proposed Order Approving Transfer to Owner Exempt.

Based upon the Transfer Motion, the testimony presented at the December 15, 2011, and the January 31, 2012, public hearings, the Joint Proposed Order filed on March 28, 2013, and other filings and evidence of record, the Commission makes the following

FINDINGS OF FACT

1. HIPOA has a certificate of public convenience and necessity to provide water and wastewater utility service to customers in the Camp Holiday service area located in Perquimans County, North Carolina.

2. Minzies Creek Village is an unincorporated nonprofit association comprised of customers of HIPOA residing in the Camp Holiday water and wastewater service area. Minzies Creek Village's duly authorized representative is attorney Lloyd C. Smith, III.

3. By Order dated June 12, 1992, in Docket No. W-386, Sub 8, the Commission approved for HIPOA an emergency assessment of $580 per lot for each of approximately 450 lots in the Camp Holiday water and wastewater service area (sections H, P, and R). The Commission Order required HIPOA to keep the revenues produced by this assessment in a separate fund, and the revenues were ordered to be used solely for upgrading the wastewater plant to bring it into compliance with North Carolina law and the regulations of the Division of Environmental Management of NCDENR, which is the predecessor agency to DWQ. This separate fund is the ECIA account.

4. Approximately one third of the $580 per lot emergency assessment approved in 1992 has not been collected. As of February 1, 2013, the ECIA account had a balance of $359.

5. On August 6, 2012, at a joint hearing of the Perquimans County Board of Commissioners and the NCDENR, the Perquimans County Board of Commissioners approved the creation of the Minzies Creek Sanitary District.

6. On August 15, 2012, the North Carolina Commission for Health Services of the Department of Health and Human Services, at the regularly scheduled quarterly meeting, approved the Petition for Minzies Creek Sanitary District upon the condition that the sanitary district receive a signed Resolution from the Perquimans County Board of Commissioners approving the creation of the district.

7. At its regularly scheduled meeting held on September 10, 2012, the Perquimans County Board of Commissioners approved the signed, written Resolution incorporating the Minzies Creek Sanitary District.

8. The existing monthly service rates for HIPOA to serve Camp Holiday approved by the Commission by Order dated February 8, 2006, in Docket No. W-386, Sub 15, are:

Monthly Metered Rates	Water	Sewer
Base charge, zero usage	$19.60	$30.00
Usage charge, per 1,000 gallons	$ 5.21	$ 5.28

9. Minzies Creek Sanitary District plans to charge the following initial monthly service rates, which are identical to the existing Commission approved rates:

Monthly Metered Rates	Water	Sewer
Base charge, zero usage	$19.60	$30.00
Usage charge, per 1,000 gallons	$ 5.21	$ 5.28

10. All the customers that testified at the December 15, 2011, and January 31, 2012, public hearings, stated they supported the formation of a sanitary district and opposed the discontinuance of utility service.

11. No customer has testified or corresponded with the Commission or Public Staff, in opposition to or expressing concerns regarding the formation of a sanitary district or the transfer of the water and wastewater systems to a sanitary district.

12. HIPOA owns and operates the water distribution system purchasing water from Perquimans County. After the transfer, the Minzies Creek Sanitary District will continue to purchase water from Perquimans County.

13. The wastewater utility system needs substantial upgrades and replacements to the effluent disposal system, and also some upgrades to the wastewater treatment plant (WWTP).

14. HIPOA does not have the funds for the necessary upgrades to the wastewater utility system. It would be extremely difficult, if not impossible, for HIPOA to obtain long-term financial institution loans. HIPOA, as a Commission regulated utility, is not eligible to apply for wastewater system long-term low interest loans and/or grants from the North Carolina Clean Water State Revolving Fund.

15. The Minzies Creek Sanitary District is eligible to apply for long-term low interest loans and/or grants for wastewater system capital upgrades from the North Carolina Clean Water State Revolving Fund.

16. The Minzies Creek Sanitary District will have the authority to levy taxes pursuant to G.S. 130A-62. HIPOA does not have authority to levy taxes.

17. The elected members of a sanitary district board are required to be residents of the sanitary district as required by G.S. 130A-50(b).

18. The Minzies Creek Sanitary District has the authority pursuant to G.S. 130A-55(22) to make special assessments against benefitted property within the Minzies Creek Sanitary District for the purpose of constructing, reconstructing, extending or otherwise improving the water utility system and/or wastewater utility system.

19. The customers in the Minzies Creek Sanitary District will have increased control of the management of the water and wastewater utility systems.

20. It is in the public interest that the water and wastewater utility systems serving Camp Holiday be transferred to the Minzies Creek Sanitary District.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

The evidence supporting this finding of fact is the Commission Order dated September 27, 1973, Docket No. W-386, Sub 0, for water utility service and the Commission Order dated September 2, 1992, Docket No. W-386, Sub 7, for wastewater utility service.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

The evidence supporting this finding of fact is the Petition to Intervene filed on November 16, 2011, by Lloyd C. Smith, III, attorney for Minzies Creek Village in this proceeding, and is uncontroverted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

The evidence supporting this finding of fact is the Commission Order dated June 12, 1992, in Docket No. W-386, Sub 8, and is uncontroverted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The evidence supporting this finding of fact is in the testimony of Public Staff Accountant Laura Bradley presented at the January 31, 2012, public hearing, and the Transfer Motion paragraph 16, and is uncontroverted.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5, 6 AND 7

The evidence supporting these findings of fact are contained in the Transfer Motion paragraphs 6, 7 and 8, and is uncontroverted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence supporting this finding of fact is contained in the Commission Order dated February 8, 2006, Docket No. W-386, Sub 15, and is uncontroverted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The evidence supporting this finding of fact is found in the Transfer Motion paragraph 14. The initial rates to be charged customers by Minzies Creek Sanitary District are identical to the current rates approved by the Commission in Docket No. W-386, Sub 15.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 10 AND 11

The evidence supporting these findings of fact is the testimony of the 16 customers that testified at the December 15, 2011, public hearing, all of whom testified they opposed the discontinuance of water and wastewater utility service and that they supported the formation of a sanitary district. In addition, all eight of the public witnesses that testified at the January 31, 2012, public hearing stated they opposed the closure of the wastewater treatment plant and supported the creation of a sanitary district. There was no testimony from any of the 24 public witnesses in opposition to the formation of a sanitary district.

The Public Staff, in its Motion Supporting Approval of Transfer in paragraph 12(b), informed the Commission that no customer has expressed to the Public Staff opposition to or concerns as to the formation of a sanitary district or the transfer of the water and wastewater utility systems to the Minzies Creek Sanitary District. The Commission records do not reveal any customer expressed opposition to the formation of a sanitary district or the transfer of the water and wastewater utility systems to the Minzies Creek Sanitary District.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence supporting this finding of fact is found in the verified Discontinuance Application. The evidence is uncontroverted that HIPOA owns the water distribution system, and purchases treated bulk water from Perquimans County. Minzies Creek Sanitary District, after the transfer, will continue to purchase treated bulk water from Perquimans County operating the water system.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence supporting this finding of fact is found in the prefiled direct testimonies and exhibits of Elaine A. Mazur, HIPOA's Treasurer; David May, Aquifer Protection Regional Supervisor for the Washington Region of DWQ; William G. Simmons, Professional Engineer; and Public Staff Utilities Engineer Babette McKemie.

David May's prefiled testimony described the compliance history of the wastewater treatment system and the actions taken by DWQ and the North Carolina Environmental Management Commission in response to the system's non-compliance with water quality laws, regulations, and permit conditions.

He testified that for many years, the system had failed to comply with environmental laws and regulations, and DWQ has issued multiple Notices of Violation (NOVs) to HIPOA for its failure to comply with applicable laws and regulations. DWQ has also issued Civil Penalty Assessments against HIPOA due to non-compliance with permit conditions set forth in Permit No. WQ0002519, which authorizes HIPOA to operate the Holiday Island wastewater system. In addition, the wastewater system has been operating under a Special Order by Consent (SOC) for the last several years. He attached a chronology of events for the System from 1973 to 1991 as Exhibit DM-1.

Mr. May described the construction of the wetland cell ponds and the reasons why the ponds failed, including that the wetland vegetation intended to provide a significant portion of planned evapotranspiration were unable to survive, therefore, negatively impacting actual effluent disposal capacity.

Mr. May also described the recent compliance issues for the wastewater system including the NOVs issued on January 3, 2007, January 2, 2008, February 1, 2008, January 7, 2011, July 18, 2011 and July 25, 2011. He described the August 4, 2009 SOC and HIPOA's failure to comply.

Mr. May stated unless significant repairs and upgrades are made, the wastewater system is unable to comply with applicable laws and regulations. The wetland cells are still failing and are unable to adequately accommodate the wastewater system's incoming wastewater flow discharge. Additionally, based on recent facility inspections, the WWTP is in need of significant upgrades and repairs to address long-term deterioration of the steel structure.

The Engineering Alternatives Analysis (Engineering Analysis) dated June 2011 by Cavanaugh and Associates (attached to the verified Discontinuance Application as Exhibit A), stated that the effluent disposal evaporative ponds wetland cells are not capable of disposing of the effluent flows generated by HIPOA's wastewater treatment plant, thereby failing to comply with environmental laws and in violation of the DWQ issued non-discharge permit. This Engineering Analysis stated one alternative for disposal of effluent would be after DWQ issues a permit, to construct and operate a non-discharge irrigation system with the estimated capital costs of $374,280.

Ms. McKemie's prefiled testimony stated the Public Staff conducted a field inspection on November 3, 2011, at which time the Public Staff observed that the existing WWTP was operating and that the repair work done to this plant in July, 2011 was sufficient to allow continued operation. She stated the WWTP is approximately forty years old and is reaching the end of its useful life. Ms. McKemie stated the wetland cells were observed to be full to the top, with no free board, and surface flow and wet areas were observed around these wetland cells.

Ms. McKemie stated the WWTP and disposal system are currently in continued and significant non-compliance with DWQ permit and requirements due to the failure of the three parallel wetland cells to adequately handle the flows. This results in a prohibited discharge to the Albemarle Sound. She stated facility is currently operating under Special Order by Consent EMC SOC WQ S09-001, AD I, issued January 4, 2010 SOC. As a result of the SOC, the facility is on a moratorium and cannot add any additional wastewater customers.

Ms. McKemie reviewed the Engineering Analysis and stated the construction of a non-discharge disposal system is the only option described in the Engineering Analysis, which could be viable alternative to wastewater system closure, and the costs associated with this option are significant.

The Commission concludes the Camp Holiday effluent evaporative ponds are materially inadequate to comply with the DWQ issued permit and need to be replaced with a DWQ approved effluent disposal system.

The Commission further concludes, based upon the prefiled testimony of DWQ's David May, that some upgrades and replacements will be required at the wastewater treatment plant.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

The evidence supporting this finding of fact is found in the prefiled testimony of HIPOA witness Elaine Mazur, HIPOA witness Barbara Bostwick, and the testimony of Public Staff accountant Laura Bradley.

HIPOA witness Mazur's prefiled testimony stated that HIPOA was told by a number of sources that grants or financing through government agencies was not available to HIPOA.

HIPOA witness Bostwick testified at the January 31, 2012, public hearing that HIPOA does not have the financial resources to operate and maintain the water and wastewater systems during the pendency of this proceeding. She testified although monthly wastewater expenses roughly equal monthly wastewater revenue, HIPOA does not have the capital reserves to pay expenses as they come due or to pay for necessary maintenance and repairs. Ms. Bostwick testified as of December 31, 2012, HIPOA had in its ECIA account $293, and in its checking account $3,659.

Public Staff witness Bradley testified at the January 31, 2012, public hearing that in the affidavit of Public Staff Financial Analyst Calvin Craig filed in this proceeding on November 16, 2011, he stated his analysis of the financial statements for HIPOA indicates that the company has an extremely weak financial position and is teetering on the brink of insolvency. Mr. Craig stated in his affidavit that his evaluation indicates that HIPOA does not currently possess the financial resources necessary to continue to provide water and wastewater utility service at Camp Holiday and that given HIPOA's current financial condition, it is very unlikely that HIPOA would be able to obtain the funding necessary to continue to provide water and wastewater service in its service area. Mr. Craig's affidavit further stated the Discontinuance Application indicates that just the initial capital outlays required to bring the systems into compliance would cost HIPOA between $375,000 and $400,000. Mr. Craig stated the financial statements simply do not indicate that HIPOA has sufficient financial resources to finance the necessary repairs from its earnings, nor is HIPOA financially strong enough to be able to qualify for loans to finance the necessary repairs.

Ms. Bradley's testimony (prefiled on November 16, 2011) stated that while the Public Staff believes it is the responsibility of management to locate funding options for each public utility that the Commission regulates, this is an unusual situation and the Public Staff believed that we needed to research options that may or may not be available.

Ms. Bradley summarized the entities she contacted and the results of the contacts. On September 8, 2011, she spoke with a representative of the North Carolina Office of Economic Recovery and Investment concerning whether there were any American Recovery and Reinvestment Act funds available. She was informed that all funding had been appropriated and spent.

On September 8, 2011, she spoke with a representative of the North Carolina Division of Water Quality – State Revolving Fund. All funding programs for wastewater are specific to local government units, which would include a sanitary district. No funding is available for privately owned utilities such as HIPOA.

On September 12, 2011, she spoke with a representative of the United States Department of Agriculture – Rural Development. The Agency had already used up its funds for the year. As a non-profit, HIPOA could have applied. However, in order to obtain a loan, HIPOA would have to prove an ability to repay the loan.

On September 12, 2011, she spoke with a representative of The Rural Center. All of its funding programs for wastewater are specific to local government units, which would include a sanitary district. No funding is available for privately owned utilities.

On September 13, 2011, she spoke with a representative of the Clean Water Management Trust Fund – Wastewater Infrastructure. The Agency makes grants for government agencies, which would include a sanitary district. No funding is available for privately owned utilities.

Finally, on September 15, 2011, she spoke with a representative of the North Carolina Rural Community Assistance Program (NCRCAP). NCRCAP does not provide grants or loans, but does provide assistance to low-income communities to help address water, wastewater, and housing needs.

The Transfer Motion stated in Paragraph 18 that Minzies Creek Sanitary District intends to pursue grants to replace the wastewater utility system. Paragraph 18 further stated that, if necessary, Minzies Creek Sanitary District may also require customers to pay additional assessments to pay for replacement of the wastewater system.

Ms. Bradley stated the Public Staff believes a sanitary district provides the best opportunity for obtaining either grants and/or long-term loans to provide the funding for the necessary wastewater system capital improvements.

The Commission concludes that HIPOA does not have adequate funds to make the necessary upgrades to the wastewater utility system and that due to HIPOA's extremely weak financial condition, it would be extremely difficult, if not impossible, for HIPOA to obtain long-term financial institution loans.

The Commission also concludes that HIPOA, as a Commission regulated wastewater utility, would not be eligible to apply for long-term loan or grants from the North Carolina Clean Water State Revolving Fund, the Rural Center, or the North Carolina Division of Water Quality – State Revolving Fund. The Commission concludes that Minzies Creek Sanitary District would be eligible to apply for funding from these three funding programs.

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

The evidence supporting these findings of fact is contained in North Carolina General Statutes 130A-62, 130A-50(b) and 130A-55(22), and is uncontroverted.

HIPOA as a Commission regulated water and wastewater utility under the Public Utilities Act North Carolina General Statutes Chapter 62, does not have the authority to levy taxes.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 19

The evidence supporting this finding of fact is the requirement stated in G.S. 130A-50(b) that elected members of a sanitary district board are required to be residents of the sanitary district, and the testimonies of the 24 customers that testified at the two public hearings. The consistent customer testimony was that the customers did not trust HIPOA, and the customers all supported the formation of a sanitary district.

The Commission concludes that the statutory requirement that the elected members of the Minzies Creek Sanitary District board are required to be residents of the sanitary district, will give the voters residing within the sanitary district more control over the management of the water and wastewater utility systems. The customer testimony was that only a few of the HIPOA board members were HIPOA water and/or wastewater customers or reside within the Camp Holiday section of Holiday Island.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 20

All 24 customers that testified at the December 15, 2011 and January 31, 2012, public hearings, stated they supported the formation of a sanitary district. The purpose of the sanitary district is to obtain ownership of the water and wastewater systems serving the Camp Holiday section of Holiday Island, Perquimans County, then make improvements to the wastewater system, and then operate the water and wastewater systems providing service to the customers within the sanitary district. None of HIPOA's customers have expressed opposition to the formation of a sanitary district, or transfer of the water and wastewater utility systems to the sanitary district.

Public Staff Accountant Laura Bradley stated the Public Staff believes, based upon the Public Staff's research, that a sanitary district provides the best opportunity for obtaining either grants and/or long-term loans to provide the funding for the necessary wastewater system capital improvements. The Public Staff's research revealed that a sanitary district was eligible to apply for long-term loans and/or grants through a number of governmental agencies, whereas HIPOA as a Commission regulated public utility was not eligible.

The affidavit of Public Staff Financial Analyst Calvin Craig stated that HIPOA has an extremely weak financial position, is teetering on the brink of insolvency, does not have sufficient financial resources to finance necessary repairs from its earnings, nor is HIPOA financially strong enough to qualify for loans to finance the necessary repairs.

On February 28, 2013, the Public Staff filed a Motion Supporting Approval of Transfer, which recommends the Commission approve the transfer to Minzies Creek Sanitary District of the water and wastewater systems serving Camp Holiday.

A sanitary district has the authority to levy taxes pursuant to G.S. 130A-62, whereas HIPOA does not have that authority. A sanitary district has the authority pursuant to G.S. 130A-55(22) to make special assessments for the purpose of constructing, reconstructing, extending or otherwise improving the water utility system and/or wastewater utility system.

The customers in the Minzies Creek Sanitary District will have increased control of the management of the water and wastewater utility systems and the elected members of a sanitary district board are required to be residents of the sanitary district as required by G.S. 130A-50(b). Customers testified that historically the majorities of HIPOA boards have not been water and/or wastewater customers, and there has been significant friction between HIPOA and its customers.

The Commission concludes it is in the public interest that the water and wastewater utility systems serving Camp Holiday be transferred to the Minzies Creek Sanitary District.

CONCLUSION

Based upon the evidence presented and the Commission records, the Commission concludes that it is in the public interest that the transfer of the water and wastewater utility systems serving Camp Holiday to Minzies Creek Sanitary District should be approved.

IT IS THEREFORE, ORDERED as follows:

1. That the Commission approves the transfer of the water and wastewater systems serving Camp Holiday from HIPOA to Minzies Creek Sanitary District, an owner exempt from Commission regulation.

2. That HIPOA shall provide written notification to the Commission within five days after the closing of the transfer has been completed.

3. That the certificate of public convenience and necessity previously issued to HIPOA for water and wastewater utility service at Camp Holiday, shall be cancelled effective the date of the systems transfer.

4. That as a component of the closing, HIPOA shall transfer to the Minzies Creek Sanitary District all the funds in the following accounts: ECIA account, the temporary surcharge account, and the Holiday Island Utility Company operating account.

5. That, prior to the transfer, the Public Staff shall review the ECIA account, the temporary surcharge account, the Holiday Island Utility Company operating account, and supporting documentation, and report to the Commission should the Public Staff believe that there have been inappropriate disbursements.

6. That a copy of this Order shall be hand delivered or mailed with sufficient postage by HIPOA to each customer no later than ten days after the date of this Order; and that HIPOA shall file a copy of the attached Certificate of Service properly signed and notarized no later than 15 days after the date of this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 24th day of April, 2013.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

rb042513.01

CERTIFICATE OF SERVICE

I, ____, mailed with sufficient postage or hand delivered to all affected customers a copy of the Order issued by the North Carolina Utilities Commission in Docket No. W-386, Sub 18, and such Order was mailed or hand delivered by the date specified in the Order.

This the _____ day of ____________________ 2013.

By: ____________________________________
Signature

____
Name of Utility Company

The above named Applicant, ________________________, personally appeared before me this day and, being first duly sworn, says that the required copy of the Commission Order was mailed or hand delivered to all affected customers, as required by the Commission Order dated _____________ in Docket No. W-386, Sub 18.

Witness my hand and notarial seal, this the ______ day of _____________ 2013.

____
Notary Public

____
Printed Name

(SEAL) My Commission Expires: ____________________________________
Date

DOCKET NO. W-386, SUB 18

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Holiday Island Property Owners	)	
Association, Inc., d/b/a Holiday Island Utility	)	
Company, 123 B Clubhouse Road, Hertford, North	)	ORDER CANCELLING
Carolina 27944, to Discontinue Water and Sewer	)	CERTIFICATE AND CLOSING
Utility Services at Camp Holiday, Perquimans	)	DOCKET
County, North Carolina	)	

BY THE CHAIRMAN: On April 24, 2013, the Commission issued the Order Approving Transfer to Owner Exempt (Order). In the Order, the Commission approved the transfer of the water and wastewater public utility serving Camp Holiday from the Holiday Island Property Owners Association, Inc., d/b/a Holiday Island Utility Company (HIPOA), to Minzies Creek Sanitary District, an owner exempt from Commission regulation. In the Order, the Commission ordered the following:

> 2. That HIPOA shall provide written notification to the Commission within five days after the closing of the transfer has been completed.
>
> 3. That the certificate of public convenience and necessity previously issued to HIPOA for water and wastewater utility service at Camp Holiday, shall be cancelled effective the date of the systems transfer.
>
> 4. That as a component of the closing, HIPOA shall transfer to the Minzies Creek Sanitary District all the funds in the following accounts: ECIA [Emergency Capital Improvement Assessment] account, the temporary surcharge account, and the Holiday Island Utility Company operating account.
>
> 5. That, prior to the transfer, the Public Staff shall review the ECIA account, the temporary surcharge account, and the Holiday Island Utility Company operating account, and the supporting documentation and report to the Commission should the Public Staff believe that there have been inappropriate disbursements.
>
> 6. That a copy of this Order shall be hand delivered or mailed with sufficient postage by HIPOA to each customer not later than ten days after the date of this Order; and that HIPOA shall file a copy of the attached Certificate of Service properly signed and notarized no later than 15 days after the date of this Order.

On May 16, 2013, HIPOA filed a copy of the properly signed and notarized Certificate of Service that was attached to the Order with the Commission indicating that the Order had been delivered to each customer of the utility.

On June 27, 2013, HIPOA filed written notice with the Commission that ownership of the water and wastewater public utility serving Camp Holiday had been transferred from HIPOA to Minzies Creek Sanitary District.

On August 27, 2013, the Public Staff filed a letter and accompanying Affidavit of Laura D. Bradley, Staff Accountant of the Accounting Division of the Public Staff with the Commission attesting to the fact that HIPOA had properly accounted for all of the funds from ECIA and surcharge accounts and that HIPOA had transferred all funds remaining in the ECIA, temporary surcharge and operating accounts to Minzies creek Sanitary District. Further, in the letter, the Public Staff requested that this docket be closed because the water and wastewater public utilities had been transferred to Minzies Creek Sanitary District, an owner exempt from Commission regulation.

WHEREFORE, after carefully reviewing the record in this docket, the Chairman concludes that HIPOA and the Public Staff have complied with the directives included in Paragraphs 2, 4, and 6 of the Ordering Paragraphs and that the water and wastewater public utilities had been transferred to Minzies Creek Sanitary District, an owner exempt from Commission regulation.

IT IS, THEREFORE, ORDERED that:

1. The certificate of public convenience and necessity previously issued to HIPOA for water and wastewater utility service at Camp Holiday is cancelled *nunc pro tunc* as of May 20, 2013, and

2. This docket shall therefore be closed.

ISSUED BY ORDER OF THE COMMISSION.
This the 18th day of September, 2013.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

Pb091813.02

WATER AND SEWER – RATE INCREASE

DOCKET NO. W-778, SUB 89

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by CWS Systems, Inc., 2335 Sanders Road, Northbrook, Illinois 60062, for Authority to Increase Rates for Water and/or Sewer Utility Service in Fairfield Harbour, Fairfield Mountains, and Sapphire Valley in Craven, Rutherford, Jackson, and Transylvania Counties, North Carolina	)	ORDER GRANTING PARTIAL RATE INCREASE AND REQUIRING CUSTOMER NOTICE

HEARD IN: Transylvania County Courthouse, 7 East Main Street, Brevard, North Carolina, on Wednesday, April 3, 2013, at 7:00 p.m.

Rutherford County Courthouse, 229 N. Main Street, Rutherfordton, North Carolina, on Thursday, April 4, 2013, at 7:00 p.m.

Craven County Courthouse, 302 Broad Street, New Bern, North Carolina, on Tuesday, April 9, 2013, at 7:00 p.m.

Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on Tuesday, May 14, 2013, at 10:00 a.m.

Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on Tuesday, June 25, 2013, at 10:00 a.m.

BEFORE: Commissioner ToNola D. Brown-Bland, Presiding; Commissioner Bryan E. Beatty; and Commissioner Susan W. Rabon

APPEARANCES:

For CWS Systems, Inc.:

Jo Anne Sanford, Sanford Law Office, P.O. Box 28085, Raleigh, North Carolina, 27611-8085

For the Using and Consuming Public:

Gina C. Holt, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: On December 3, 2012, CWS Systems, Inc. (Applicant, CWSS, or Company), filed a letter notifying the Commission of its intent to file a general rate case as required by Commission Rule R1-17(a). On December 31, 2012, CWSS filed an application with the Commission seeking authority to increase its rates for providing water and/or sewer utility service in Fairfield Harbour, Fairfield Mountains, and Sapphire Valley in Craven, Rutherford, Jackson, and Transylvania Counties, North Carolina.

By Order dated January 30, 2013, the Commission declared the above-captioned proceeding to be a general rate case pursuant to G.S. 62-137; suspended the proposed rates for a period of up to 270 days pending further investigation and hearing; scheduled customer hearings in Rutherfordton, Brevard, and New Bern, North Carolina; and scheduled an evidentiary hearing in Raleigh, North Carolina. The Applicant was required to provide customer notice of the hearings and the proposed rate increase to all affected customers. On February 11, 2013, the Commission issued an Errata Order to correct an inadvertent error in Appendix B, Page 1 of 4, (in the first paragraph, the first sentence was incomplete) of the January 30, 2013 Order.

The intervention and participation in this proceeding by the Public Staff is made and recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e). No other party intervened.

On March 7, 2013, the Applicant filed its Certificate of Service indicating that customer notice was provided as required by the Commission's January 30, 2013 Order.

On March 18, 2013, the Public Staff filed a letter from the Fairfield Harbour Property Owners Association (POA) requesting that the location of the customer hearing in New Bern be changed to the Fairfield Harbour Fire Station/Community Center. On that same date, the Public Staff filed its response to the POA informing it of the change in Commission policy whereby all public hearings before NCUC Commissioners are to be held at county courthouses.

On March 27, 2013, the Applicant prefiled the direct testimony of Lena Georgiev, Manager of Regulatory Affairs for Utilities, Inc.[1]

Public hearings were held as scheduled. The following public witnesses testified at the public hearings held in this proceeding:

April 3 -	Brevard	John Dubinsky, Tony Hollis, John Adams, Patricia Chambers, Mary Ann Lovelace, Marlene Schroeder, Earl Hollis, IV
April 4 -	Rutherfordton	Jack Zinselmeier
April 9 -	New Bern	No public witnesses testified.

[1] CWSS is a wholly owned subsidiary of Utilities, Inc.

On April 23, May 1, and May 3, 2013, the Public Staff filed motions requesting that the Commission approve extensions of time for the filing of its testimony and the filing of the Company's rebuttal testimony. The motions were granted by Orders issued April 25, May 1, and May 3, 2013, respectively.

On May 6, 2013, the Public Staff prefiled the affidavits and exhibits of Public Staff witnesses Windley E. Henry, Staff Accountant, Accounting Division; Fenge Zhang, Staff Accountant, Accounting Division; and O. Bruce Vaughan, Utilities Engineer, Water Division; and the testimony and exhibits of Gina Y. Casselberry, Utilities Engineer, Water Division.

Also, on May 6, 2013, the Public Staff and CWSS filed a "Stipulation of the Public Staff and CWS Systems, Inc." (Stipulation), which was entered on May 6, 2013, that settled all of their issues in this rate case proceeding. On May 8, 2013, the Applicant filed a report addressing the service-related concerns expressed at the public hearings.

On May 10, 2013, the Commission issued an Order Continuing Evidentiary Hearing, which rescheduled the evidentiary hearing to June 25, 2013, and required the Public Staff or the Applicant to prefile testimony to specifically address the return on equity component of rate of return, which was a part of the Stipulation. The Commission also requested that the Applicant prefile additional testimony addressing the specific reasons the Applicant's proposed rate increases are necessary.

On May 14, 2013, the Public Staff filed revisions to witness Casselberry's testimony and her Exhibits 5 and 9 relating to revenues associated with sewer utility service in the Fairfield Mountains service area. The Public Staff also filed the revised affidavit of Public Staff witness Henry, and his revised Exhibit II.

On May 29, 2013, the Public Staff filed a motion for extension of time for the Company and the Public Staff to file the additional testimony required by the May 10, 2013 Order, which was granted by Commission Order issued on May 30, 2013. On May 30, 2013, CWSS filed a Notice of Withdrawal and Substitution of Counsel for Utilities Inc., which informed the Commission of the withdrawal of Christopher Ayers as counsel for CWSS, and the substitution of Jo Anne Sanford as counsel.

On May 31, 2013, the Applicant filed a Notification of Adoption of Testimony, informing the Commission that witness Lowell M. Yap, Jr., would adopt the prefiled testimony of witness Lena Georgiev, who was no longer employed by the Company. Also, on May 31, 2013, the Public Staff filed a Second Revised Affidavit of Windley Henry, which corrected additional information.

On June 6, 2013, the Applicant filed the supplemental direct testimony of Lowell M. Yap, Jr., and the Public Staff filed the testimony and exhibits of Calvin C. Craig, III. On June 14, 2013, CWSS filed a motion requesting that witness Yap be excused from appearing at the evidentiary hearing scheduled for June 25, 2013, and included a verification of his June 6, 2013 testimony.

On June 19, 2013, CWSS filed a follow-up report prepared by CWSS Regional Director, Martin J. Lashua, which described the status of repairs being made to certain roads in the Fairfield Mountains community of Rumbling Bald Resort (RBR). An email from the RBR Property Owners Association, expressing appreciation for the work, accompanied the report.

On June 19, 2013, the Commission issued an Order that conditionally excused witness Yap, upon compliance with the following requirements:

- That witness Yap file additional testimony listing and describing, by operating entity, the primary increases in operating expenses and plant additions since the last rate case proceeding which explain why the proposed water and sewer revenue increases are necessary, including the corresponding approximate dollar amount for each specific, explanatory reason provided; and

- That the Public Staff or CWSS provide a witness at the hearing to answer questions that may arise from the Commission concerning this question.

On June 20, 2013, the Public Staff filed a Motion for Order Excusing Witnesses from Hearing. On June 21, 2013, the Public Staff filed corrections to exhibits of witness Craig.

On June 24, 2013, the Applicant filed additional supplemental direct testimony of witness Yap. On that same date, the Public Staff and CWSS (collectively, the Parties) filed a Revised Stipulation agreeing to, among other things: (1) the levels of rate base and revenues set forth in Henry Revised Exhibit I for Fairfield Harbour, Henry Revised Exhibit II for Fairfield Mountains, and Henry Exhibit III for Sapphire Valley; (2) the levels of expenses set forth in Zhang Exhibits I, II, and III attached to the affidavits of Public Staff witnesses Henry and Zhange and the revised affidavit[1] and exhibits of Public Staff witness Henry; (3) the proposed rates as set forth in Stipulation Exhibit 1 and the revised testimony and exhibits of Public Staff witness Casselberry; (4) the acceptance of all prefiled testimony and exhibits, as revised, of the Parties into evidence without objection; and (5) the waiving of cross-examination of all Parties' witnesses. Also on June 24, 2013, Public Staff witness Henry filed revised Henry Exhibit I, and Public Staff witness Casselberry filed revised Casselberry Exhibits 12, 13, and 14 (page 3 of 3), which supported the terms of the Revised Stipulation.

By Order dated June 24, 2013, the Commission excused all witnesses of the Company and the Public Staff, and admitted all prefiled revised testimony, exhibits, and affidavits into evidence.

[1] On May 14, 2013, the Public Staff filed the revised affidavit of witness Henry and a revised Henry Exhibit II to correct inadvertent errors pertaining to the revenues associated with sewer utility service in the Fairfield Mountains service area that were discovered in the testimony of witness Casselberry. On May 31, 2013, the Public Staff filed the second revised affidavit of witness Henry to correct inadvertent errors pertaining to the rate of return percentages contained on Page 3 of the May 14, 2013 revised affidavit.

On June 25, 2013, an evidentiary hearing was held in Raleigh, North Carolina, as scheduled. At that hearing, the Applicant and the Public Staff moved the admission of the Revised Stipulation and Revised Stipulation Exhibit I into evidence. No customers presented testimony at the evidentiary hearing.

On June 26, 2013, CWSS filed the original verification of the additional supplemental testimony that was filed by witness Yap, on June 24, 2013. On July 26, 2013, CWSS and the Public Staff filed a Joint Proposed Order Granting Partial Rate Increase and Requiring Customer Notice.

On the basis of the application, the Revised Stipulation and Revised Stipulation Exhibit I, the revised testimony and exhibits of Public Staff witnesses Casselberry and Craig, the revised affidavit and exhibits of Public Staff witness Henry, the affidavits of Public Staff witnesses Vaughan and Zhang, the testimony and additional supplemental testimony of Company witness Yap, and the other evidence of record, the Commission is of the opinion that the provisions of the Revised Stipulation are just and reasonable. Accordingly, the Commission makes the following:

FINDINGS OF FACT

1. CWSS is a corporation duly organized under the law and is authorized to do business in the State of North Carolina. CWSS is a franchised public utility providing water and sewer utility service to customers in North Carolina. CWSS is a wholly owned subsidiary of Utilities, Inc.[1]

2. CWSS is properly before the Commission pursuant to Chapter 62 of the General Statutes of North Carolina, for a determination of the justness and reasonableness of its proposed rates and charges for its water and sewer utility operations.

3. CWSS serves approximately: 4,459 residential water customers, 3,036 residential sewer customers, 147 commercial water customers, 71 commercial sewer customers, 1,734 availability water customers, and 1,559 availability sewer customers.

[1] Utilities, Inc. owns regulated utilities in approximately 15 states, including several in North Carolina. Presently, the regulated utilities owned by Utilities, Inc. in North Carolina are: (1) CWSS; (2) Carolina Water Service, Inc. of North Carolina; (3) Bradfield Farms Water Company; (4) Carolina Trace Utilities, Inc.; (5) Elk River Utilities, Inc.; and (6) Transylvania Utilities, Inc.

4. A total of eight customers from the Fairfield Mountains and Sapphire Valley service areas testified at the public hearings, with five of them expressing service-related concerns. At the customer hearing in Brevard, four customers from the Sapphire Valley service area testified about periodic water outages and boil water notices. One customer from the Fairfield Mountains service area testified at the Rutherfordton hearing regarding the need for CWSS to repair asphalt road damage that he attributed to CWSS. No customers from the Fairfield Harbour service area appeared at the public hearings.

5. CWSS filed a report with the Commission on June 19, 2013, regarding the status of repairs to roads in RBR, a community in the Fairfield Mountains service area. On July 8, 2013, a letter was filed with the Commission indicating CWSS had completed all road repair work to the satisfaction of the customer who testified at the public hearing in Rutherfordton and to the satisfaction of the RBR Property Owners Association.

6. The overall quality of service provided by CWSS is good.

7. The test period for purposes of establishing rates in this proceeding is the 12-month period ended December 31, 2011.

8. The present water utility rates have been in effect since August 2011.[1] The current sewer rates for Fairfield Mountains have been in effect since October 2010,[2] and the sewer rates for Sapphire Valley and Fairfield Harbour have been in effect since January 2009.[3]

9. CWSS and the Public Staff entered into and filed a Revised Stipulation and Revised Stipulation Exhibit I on June 24, 2013, which settled all their issues.

10. CWSS's present and proposed water and/ or sewer utility service rates are as follows:

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[1] In Docket No. W-778, Sub 88, an Order Granting Partial Rate Increase and Requiring Customer Notice was issued on August 3, 2011.

[2] In Docket No. W-778, Sub 87, an Order Approving Tariff Revision was issued on October 29, 2010.

[3] In Docket No. W-778, Sub 81, an Order Granting Partial Rate Increase and Requiring Customer Notice was issued on January 16, 2009.

WATER AND SEWER – RATE INCREASE

FAIRFIELD MOUNTAINS SERVICE AREA
HIGHLAND SHORES SUBDIVISION
APPLE VALLEY AND
LAUREL MOUNTAIN ESTATES (water only)
(Rutherford County)

Monthly Metered Water Rates:

	Present	Proposed
Base charge, zero usage		
Residential	$ 18.00	$ 19.96
Commercial and Other:		
5/8” meter	$ 18.00	$ 19.96
3/4” meter	$ 27.00	$ 29.94
1” meter	$ 45.00	$ 49.90
1.5” meter	$ 90.00	$ 99.80
2” meter	$144.00	$159.68
3” meter	$270.00	$299.40
4” meter	$450.00	$499.01
6” meter	$900.00	$998.01

	Present	Proposed
Master meter where each unit is billed individually		$ 19.96
Usage charge, per 1,000 gallons	$ 6.61	$ 7.33
Average monthly residential bill (2,365 gal.)	$ 33.63	$ 37.30

Percent Increase 10.9%

Monthly Sewer Rates:

	Present	Proposed
Residential:		
Collection charge, per dwelling unit	$ 13.98	$ 16.29
Treatment charge, per dwelling unit	$ 32.50	$ 34.50
Total monthly flat rate bill, per dwelling unit	$ 46.48	$ 50.69

Percent Increase 9.1%

Commercial and Other:

Minimum monthly collection and treatment charge	$ 46.48	$ 50.69
Monthly collection and treatment charge For customers who do not take water service (per single family equivalent)	$ 46.48	$ 50.69
Treatment charge per dwelling unit:		
Small (less than 2,500 gallons per month)	$ 37.50	$ 39.50
Medium (2,500 to 10,000 gallons per month)	$ 62.50	$ 66.00
Large (over 10,000 galons per month)	$150.00	$157.50
Collection Charge, per 1,000 gallons	$ 12.58	$ 12.58

<u>FAIRFIELD SAPPHIRE VALLEY SERVICE AREA</u>
(Jackson and Transylvania Counties)

<u>Monthly Metered Water Rates</u>:

	<u>Present</u>	<u>Proposed</u>
Base charge, zero usage		
Residential	$ 15.91	$ 19.51
Commercial and Other:		
5/8” meter	$ 15.91	$ 19.51
3/4” meter	$ 23.87	$ 29.27
1” meter	$ 39.78	$ 48.78
1.5” meter	$ 79.55	$ 97.55
2” meter	$127.28	$156.08
3” meter	$238.65	$292.66
4” meter	$397.75	$487.76
6” meter	$795.50	$975.52
Master meter where each unit is billed individually		$ 19.51
Usage charge, per 1,000 gallons	$ 7.34	$ 9.00
Average monthly residential bill (2,230 gal.)	$ 32.28	$ 39.58
Percent Increase 22.6%		
Water availability rate	$ 7.28	$ 8.93

WATER AND SEWER – RATE INCREASE

Monthly Sewer Rates:

	Present	Proposed
Residential:		
Flat rate per dwelling unit:	$ 26.39	$ 42.89
Percent Increase 62.5%		
Commercial and Other:		
Minimum rate	$ 26.39	$ 42.89
Customer who does not take water service (per single family equivalent)	$ 26.39	$ 42.89

	Present	Proposed
Base Facility Charge:		
5/8” meter	$ 11.60	$ 18.85
3/4” meter	$ 17.40	$ 28.28
1” meter	$ 29.00	$ 47.13
1.5” meter	$ 58.00	$ 94.26
2” meter	$ 92.80	$150.82
3” meter	$174.00	$282.78
4” meter	$290.00	$471.31
6” meter	$580.00	$942.61
Usage charge, per 1,000 gallons	$ 6.00	$ 9.75
Sewer availability rate	$ 6.15	$ 6.15

FAIRFIELD HARBOUR SERVICE AREA
(Craven County)

Monthly Metered Water Rates:

	Present	Proposed
Base Charge, zero usage		
Residential	$ 8.80	$ 10.12
Commercial and Other:		
5/8” meter	$ 8.80	$ 10.12
3/4” meter	$ 13.20	$ 15.18
1” meter	$ 22.00	$ 25.30
1.5” meter	$ 44.00	$ 50.06
2” meter	$ 70.40	$ 80.96

3” meter	$132.00	$151.80
4” meter	$220.00	$253.00
6” meter	$440.00	$506.00
Master meter where each unit is billed individually		$ 10.81
Usage charge, per 1,000 gallons	$ 2.41	$ 2.77
Average monthly residential bill (4,630 gal.)	$ 19.96	$ 22.95
Percent Increase 15.0%		
Water availability rate	$ 3.00	$ 3.00

Monthly Sewer Rates:

	Present	Proposed
Residential:		
Flat rate per dwelling unit:	$ 29.48	$ 40.11
Percent Increase 36.1%		
Commercial and Other:		
Customers who do not take water service (flat monthly rate)	$ 29.48	$ 40.11
Monthly Metered Rates:		
Base Charge, zero usage		
5/8” meter	$ 7.79	$ 10.60
3/4” meter	$ 11.69	$ 15.91
1” meter	$ 19.47	$ 26.49
1.5” meter	$ 38.95	$ 53.00
2” meter	$ 62.32	$ 84.80
3” meter	$116.85	$159.00
4” meter	$194.75	$265.00
6” meter	$389.50	$529.99
Usage charge, per 1,000 gallons	$ 4.36	$ 5.93
Sewer availability rate	$ 2.05	$ 2.05

11. CWSS's total water operating revenue deductions under present rates are:

Fairfield Harbour	$ 429,963
Fairfield Mountains	$ 373,042
Sapphire Valley	$ 660,495

12. CWSS's total sewer operating revenue deductions under present rates are:

Fairfield Harbour	$ 610,786
Fairfield Mountains	$ 319,794
Sapphire Valley	$ 368,819

13. CWSS's present water rates produce the following service revenues:

Fairfield Harbour	$ 485,470
Fairfield Mountains	$ 471,578
Sapphire Valley	$ 792,379

14. CWSS requested an increase in its water utility service rates that would produce the following service revenues and percentage increases:

Fairfield Harbour	$ 553,183	13.95%
Fairfield Mountains	$ 522,936	10.89%
Sapphire Valley	$ 971,656	22.63%

15. CWSS's present sewer rates produce the following service revenues:

Fairfield Harbour	$ 678,271
Fairfield Mountains	$ 305,287
Sapphire Valley	$ 316,401

16. CWSS requested an increase in its sewer utility service rates that would produce the following service revenues and percentage increases:

Fairfield Harbour	$ 914,493	34.83%
Fairfield Mountains	$ 327,693	7.34%
Sapphire Valley	$ 508,463	60.70%

17. CWSS's water original cost rate base at December 31, 2011, updated to February 28, 2013, is:

Fairfield Harbour	$ 935,612
Fairfield Mountains	$ 1,560,862
Sapphire Valley	$ 2,403,194

18. CWSS's sewer original cost rate base at December 31, 2011, updated to February 28, 2013, is:

Fairfield Harbour	$ 2,086,324
Fairfield Mountains	$ 169,383
Sapphire Valley	$ 1,099,336

19. The reasonable level of water plant in service for use in this proceeding is:

Fairfield Harbour	$ 3,823,782
Fairfield Mountains	$ 2,699,874
Sapphire Valley	$ 8,015,697

20. The reasonable level of sewer plant in service for use in this proceeding is:

Fairfield Harbour	$ 8,817,132
Fairfield Mountains	$ 367,163
Sapphire Valley	$ 3,560,603

21. Accumulated depreciation consists of the following balances for water operations:

Fairfield Harbour	$ 1,206,944
Fairfield Mountains	$ 340,852
Sapphire Valley	$ 1,374,673

22. Accumulated depreciation consists of the following balances for sewer operations:

Fairfield Harbour	$ 2,353,336
Fairfield Mountains	$ 101,676
Sapphire Valley	$ 350,628

23. Contributions in aid of construction (CIAC), reduced by accumulated amortization of CIAC, consists of the following amounts for water operations:

Fairfield Harbour	$ 1,590,578
Fairfield Mountains	$ 685,964
Sapphire Valley	$ 4,055,343

24. CIAC, reduced by accumulated amortization of CIAC, consists of the following amounts for sewer operations:

Fairfield Harbour	$ 4,148,665
Fairfield Mountains	$ 81,808
Sapphire Valley	$ 2,052,888

25. Pro forma plant, net of retirements, included in the rate base for water operations, as stipulated, consists of the following amounts:

Fairfield Mountains	$	41,580
Sapphire Valley	$	60,710

26. Pro forma plant included in the rate base for sewer operations, as stipulated, consists of the following amount:

Fairfield Harbour	$	354,271

27. CWSS is entitled to total rate case costs of $132,221, as stipulated and supported in Henry Revised Exhibits I and II and Henry Exhibit III, consisting of $22,317 in legal fees; $9,802 in paper stock and postage for customer notices; $124 for express mailing charges, copying, printing, and administrative costs; $98,878 for Water Service Corporation personnel costs; and $1,100 in travel expenses. Also, the unamortized balance of rate case costs for the Docket No. W-778, Sub 88 rate case proceeding (Sub 88 proceeding) were calculated on an individual system basis and are $12,771 for Fairfield Harbour; $7,195 for Fairfield Mountains; and $11,649 for Sapphire Valley. The Parties agree that these total rate case costs of $163,836 should be amortized over three years, resulting in annual rate case expense of $54,612, which should be allocated[1] to each of the following entities as follows:

Fairfield Harbour	$	25,501
Fairfield Mountains	$	10,966
Sapphire Valley	$	18,145

28. It is reasonable and appropriate to calculate regulatory fees using the statutory rate of 0.12%.

29. It is reasonable and appropriate to calculate gross receipts tax based on the levels of revenues and the statutory rate of 4% for water operations and 6% for sewer operations.

30. It is reasonable and appropriate to calculate the state and federal income taxes based on the corporate rates of 6.9% for state income tax and 34% for federal income tax.

31. Public Staff witness Calvin C. Craig, III, pursuant to the Commission's May 10, 2013 Order, provided adequate evidence in support of the agreed-upon return on common equity of 9.65%.

[1] The unamortized rate case costs related to the Sub 88 proceeding for each rate entity were based upon the Sub 88 Stipulation amount after amortization for 24 months.

WATER AND SEWER – RATE INCREASE

32. The reasonable and appropriate overall weighted rate of return on rate base is 8.13%, which is based upon a capital structure of 50.00% long-term debt with an embedded cost of debt of 6.60%, and 50.00% common equity with a return on common equity of 9.65%.

33. The Parties agree that CWSS is entitled to changes in rates that will produce the following water service revenues and percentage increases:

	Water Revenues	Percentage Increase
Fairfield Harbour	$ 512,933	5.66%
Fairfield Mountains	$ 515,607	9.34%
Sapphire Valley	$ 899,930	13.57%

Said revenues reflect a stipulated annual increase in water service revenues as follows:

	Annual Water Revenue Increase
Fairfield Harbour	$ 27,453
Fairfield Mountains	$ 44,029
Sapphire Valley	$107,551

34. The Parties agree that CWSS is entitled to changes in rates that will produce the following sewer service revenues and percentage increases:

	Sewer Revenues	Percentage Increase
Fairfield Harbour	$ 844,511	24.51%
Fairfield Mountains	$ 335,022	9.74%
Sapphire Valley	$ 504,222	59.36%

Said revenues reflect a stipulated annual increase in sewer service revenues as follows:

	Annual Sewer Revenue Increase
Fairfield Harbour	$166,240
Fairfield Mountains	$ 29,735
Sapphire Valley	$187,821

35. CWSS's total water operating revenue deductions under the agreed-upon rates are:

Fairfield Harbour	$ 441,027
Fairfield Mountains	$ 390,771
Sapphire Valley	$ 703,734

36. CWSS's total sewer operating revenue deductions under the agreed-upon rates are:

Fairfield Harbour	$ 681,221
Fairfield Mountains	$ 325,149
Sapphire Valley	$ 413,555

37. The water and sewer service rates and charges agreed to by CWSS and the Public Staff, provided in Revised Stipulation Exhibit 1, are as follows:

<u>FAIRFIELD MOUNTAINS SERVICE AREA</u>
<u>HIGHLAND SHORES SUBDIVISION</u>
<u>APPLE VALLEY</u>
<u>LAUREL MOUNTAIN ESTATES (water only)</u>
(Rutherford County)

<u>Monthly Metered Water Rates</u>:

Residential	$ 19.68
Commercial and Other:	
5/8" meter	$ 19.68
3/4" meter	$ 29.52
1" meter	$ 49.20
1.5" meter	$ 98.40
2" meter	$157.44
3" meter	$295.20
4" meter	$492.00
6" meter	$984.00
Usage charge, per 1,000 gallons	$ 7.23

<u>Monthly Sewer Rates</u>:

Residential:	
Collection charge, per dwelling unit	$ 17.69
Treatment charge, per dwelling unit	$ 34.50
Total monthly flat rate bill, per dwelling unit	$ 52.19
Commercial and Other:	
Minimum monthly collection and treatment charge:	$ 52.19

WATER AND SEWER – RATE INCREASE

Monthly collection and treatment charge for customers who do not take water service (per single family equivalent):	$ 52.19

Treatment charge per dwelling unit:

Small (less than 2,500 gallons per month)	$ 39.50
Med. (2,500 to 10,000 gallons per month)	$ 66.00
Med./O[1] (2,500 to 10,000 gallons per month)	$131.50
Large (over 10,000 gallons per month)	$157.50

(Note: All treatment charges are Town of Lake Lure charges. Classification of user is determined by the Town of Lake Lure.)

Collection charge, per 1,000 gallons	$ 12.58

<u>FAIRFIELD SAPPHIRE VALLEY SERVICE AREA</u>
(Jackson and Transylvania Counties)

<u>Monthly Metered Water Rates</u>:

Base charge, zero usage

Residential	$ 18.07

<u>Monthly Metered Water Rates (con't)</u>:

Commercial and Other:

5/8" meter	$ 18.07
3/4" meter	$ 27.11
1" meter	$ 45.18
1.5" meter	$ 90.35
2" meter	$144.56
3" meter	$271.05
4" meter	$451.75
6" meter	$903.50

Usage charge, per 1,000 gallons	$ 8.34
Water availability rate	$ 8.25

[1] Medium user/outside rate.

WATER AND SEWER – RATE INCREASE

Monthly Sewer Rates:

Residential:	
Flat rate per dwelling unit:	$ 42.08
Commercial and Other:	
Minimum rate	$ 42.08
Customer who does not take water service (per single family equivalent)	$ 42.08
Base facility charge:	
5/8” meter	$ 18.50
3/4” meter	$ 27.75
1” meter	$ 46.25
1.5” meter	$ 92.50
2” meter	$148.00
3” meter	$277.50
4” meter	$462.50
6” meter	$925.00
Usage charge, per 1,000 gals	$ 9.57
Sewer availability rate	$ 9.80

FAIRFIELD HARBOUR SERVICE AREA
(Craven County)

Monthly Metered Water Rates:

Base charge, zero usage	
Residential	$ 9.30
Commercial and Other:	
5/8” meter	$ 9.30
3/4” meter	$ 13.95
1” meter	$ 23.25
1.5” meter	$ 46.50
2” meter	$ 74.40
3” meter	$139.50
4” meter	$232.50
6” meter	$464.00
Usage charge, per 1,000 gallons	$ 2.55
Water availability rate	$ 3.15

Monthly Sewer Rates:

Residential:	
Flat rate, per dwelling unit	$ 36.70
Commercial and Other:	
Customers who do not take water service (flat monthly rate)	$ 36.70

Monthly Metered Sewer Rates:

Base charge (zero usage)	
5/8” meter	$ 9.85
3/4” meter	$ 14.78
1” meter	$ 24.63
1.5” meter	$ 49.25
2” meter	$ 78.80
3” meter	$147.75
4” meter	$246.25
6” meter	$492.50
Usage charge, per 1,000 gallons	$ 5.46
Sewer availability rate	$ 2.55

38. The rates agreed to by CWSS and the Public Staff, as provided hereinabove and included in Appendices A-1, A-2, and A-3 attached hereto, are just and reasonable and should be approved.

39. The Applicant’s request to increase the returned check charge from $10.00 to $25.00 is reasonable and should be approved.

40. The Applicant’s request to add the following language to the CWSS Fairfield Harbour, Sapphire Valley, and Fairfield Mountains tariffs is reasonable and should be approved:

> Customers who ask to be reconnected within nine months of disconnection will be charged the base monthly charge for zero usage for the service periods they were disconnected.

41. The Applicant and the Public Staff agreed to waive their respective right of appeal of a final Order of the Commission incorporating the agreed-upon matters in the Revised Stipulation.

42. The Revised Stipulation contains the provision that CWSS and the Public Staff agree that none of the positions, treatments, figures, or other matters reflected in the Revised Stipulation should have any precedential value, nor should they otherwise be used in any subsequent proceedings before this Commission or any other regulatory body as proof of the matter at issue.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

The evidence for the foregoing findings of fact is contained in the application; in the Commission records; in the adopted testimony and supplemental direct testimony of CWSS witness Yap; in the revised testimony and exhibits of Public Staff witness Casselberry; in the testimony and revised exhibits of Public Staff witness Craig; in the affidavits of Public Staff witnesses Vaughan and Zhang; in the revised affidavit, exhibits, and revised exhibits of Public Staff witness Henry; in the testimony of the public witnesses; and in the Revised Stipulation and Revised Stipulation Exhibit I.

With respect to concerns expressed by customers at the hearing held in Brevard, North Carolina, four customers testified regarding periodic water outages and boil water notices. However, each of the customers stated that the Company had responded and repaired the outages in a reasonable manner. Thus, there appeared to be no outstanding service issues raised at the Brevard hearing.

At the customer hearing in Rutherfordton, North Carolina, one customer testified regarding CWSS's inadequate patching of roads in his community of RBR after CWSS dug up and repaired water line breaks. He asserted that CWSS needs to provide quality asphalt road repair to the present patches on the road.

Pursuant to the Commission's Order Scheduling Hearings and Requiring Customer Notice issued on January 30, 2013, CWSS filed, on June 19, 2013, a Report of Satisfaction of Customer Complaint which addressed the customer's service issue regarding the community's dissatisfaction with the condition of asphalt road patches in the RBR subdivision of the Fairfield Mountains service area, and the desire that CWSS repave certain roads that were repeatedly dug up and patched by CWSS due to water main breaks. The Report indicated that repairs were made to 11 of 13 areas requested to the specifications of the community. On July 8, 2013, the Applicant filed a letter from a representative of RBR indicating that the Company had completed the agreed upon road repairs to the satisfaction of the community. The Report also stated that, in the future, the Company will follow the paving specifications and permit process developed by RBR and will use the independent local area paving contractor that RBR has endorsed.

In regard to concerns expressed by customers through consumer statements of position, Public Staff witness Vaughan stated in his affidavit that the Public Staff received a total of 23 customer statements: three from Fairfield Harbour customers, three from Fairfield Mountains customers, and 17 from Sapphire Valley customers. Witness Vaughan further stated that only three of the customer statements from customers in the Sapphire Valley service area concerned customer service issues. Those issues were that there had been frequent interruptions in service; the service has not improved since the last rate case, and, therefore, a rate increase is not warranted; and the situation that CWSS took over a year to fix a leak. After the Public Staff's investigation, witness Vaughan, however, concluded that the Applicant has been providing adequate service based on: (1) the fact that the Public Staff received only a small number of customer complaints; (2) the information provided by the Applicant; and (3) the Applicant received acceptable compliance reports from the North Carolina Department of Environmental and Natural Resources Divisions of Water Resources, Public Water Supply Section, and the Division of Water Quality, Aquifer Protections Section.

Based on the foregoing and our review of the report on customer concerns filed by the Company; the testimony of the public witnesses; the Public Staff's investigation and findings; the post-hearing report of the Company's completion of the road repairs; and the post-hearing letter from the RBR Property Owner's Association confirming the Company's completion of and its satisfaction with the repairs performed by the Company; the Commission finds and concludes that CWSS has adequately addressed the service-related concerns expressed by the public witnesses, and that the Company's overall quality of service is good.

With respect to customer concerns expressed in opposition to the proposed rate increase, pursuant to the Commission's May 10, 2013, Order Continuing Evidentiary Hearing, CWSS filed, on June 6, 2013, the supplemental direct testimony of witness Yap, and, on June 24, 2013, filed additional supplemental direct testimony of witness Yap, which provided specific reasons for the increases in operating expenses and plant additions since its last rate case proceeding, and explained why its proposed water and sewer revenue increases are necessary.

In regard to the proposed rate increase for Fairfield Harbour, witness Yap summarized that increases in maintenance and repairs expense, chemicals, increases in plant additions since the last rate case proceeding, and increases in insurance costs are the primary reasons for such rate increase. In particular, witness Yap stated that such increases related to: water line repairs; sewer line point repairs; changing the type of chemical used to sequester iron and manganese in the water from a phosphate called OP 37 to Ferro Quest and also increasing the amount of the sequestering agent used; adding a polymer to the chemicals used for sludge treatment; and the installation of plant improvements costing over $400,000, resulting in increased depreciation expense of approximately $14,000. Such plant improvements included a new sewer plant addition which was placed in service on June 24, 2013, prior to the evidentiary hearing.

Concerning the proposed rate increase for Fairfield Mountains, witness Yap summarized that increases in maintenance and repair expenses, increases in plant additions since the last rate case proceeding, and increases in insurance costs are the primary reasons for such rate increase. In particular, witness Yap stated that such increases related to: water main repairs, sewer line leak repairs, and the installation of plant improvements costing over $300,000, resulting in increased depreciation expense of approximately $1,500.

Finally, with respect to the proposed increase for Sapphire Valley, witness Yap summarized that increases in maintenance and repairs expense, chemicals, and increases in plant additions since the last rate case proceeding are the primary reasons for such rate increase. In particular, witness Yap stated such increases related to: water service line repairs; water main leak repairs; sewer liftstation maintenance, including electrical repairs; adding sodium hypochorite to a new well placed in service; adding sodium bicarbonate to the wastewater treatment plant to increase alkalinity; and the installation of plant improvements costing over $800,000, resulting in increased depreciation expense of approximately $40,000.

Based upon the additional supplemental testimony and the application of the Company, the Commission observes that over 60% of the stipulated rate increases for the Fairfield Harbour and Fairfield Mountain service areas and over 76% of the stipulated rate increase for the Sapphire Valley service area is attributable to maintenance and repair expenses and plant improvements, including related depreciation expense. The Commission is of the opinion that CWSS should maintain, improve, and replace its water and sewer utility infrastructure as needed, and on a regular basis, in order to provide adequate utility service to its customers. Further, the Commission recognizes that, pursuant to G.S. 62-133 CWSS is allowed to recover, through rates established in a general rate case proceeding, its reasonable and prudent costs of providing water and sewer utility service. The Commission finds and concludes that CWSS has adequately explained the primary increases in operating expenses and plant additions since its last general rate case proceeding, and that CWSS's increased operating expenses and costs of plant additions were reasonable and necessary to maintain its facilities and services.

The May 10, 2013 Order Continuing Evidentiary Hearing, also requested that the Public Staff or the Company prefile additional testimony to specifically address the return on equity component of the overall rate of return that the Parties agreed to in their Stipulation, filed on May 5, 2013, and to provide support for the position that the return on equity component is just and reasonable for use in this proceeding. In response to the Commission's Order, Public Staff witness Craig, on June 6, 2013, filed additional testimony supporting the return on equity agreed to by the Parties.

Witness Craig testified that it is widely recognized that a public utility should be allowed a rate of return on capital which will allow the utility, under prudent management, to attract capital under the criteria or standards referenced by the Hope and Bluefield decisions. He maintained that if the allowed rate of return is set too high, consumers are burdened with excessive costs, current investors receive a windfall, and the utility has an incentive to overinvest. However, if the return is set too low and the utility is not able to attract capital on reasonable terms to meet future expansion for its service area, witness Craig asserted that future service obligations may be impaired. Witness Craig explained that because a public utility is capital intensive, the cost of capital is a very large part of its overall revenue requirement and is a crucial issue for a company and its ratepayers.

Additionally, witness Craig noted that the Hope[1] and Bluefield[2] standards are embodied in G.S. 62-133(b)(4), which requires that the allowed rate of return be sufficient to enable a utility by sound management

> to produce a fair return for its shareholders, considering changing economic conditions and other factors, . . . to maintain its facilities and 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 to its existing investors.

Witness Craig testified that he used the discounted cash flow (DCF) method, the risk premium method, and the comparable earnings method to determine the cost of equity capital for CWSS. In his testimony he described each of the three methods in detail. He summarized that the cost of equity ranges indicated by his study as are follows: 8.80% to 9.80% for the DCF model and 8.90% to 10.1% for the comparable earnings method, the midpoints of the two ranges being 9.30% and 9.50%, respectively. In addition, he stated that the cost of equity produced by the risk premium model is 9.59%. The Parties stipulated that the cost of common equity should be 9.65%.

Witness Craig also discussed to what extent the agreed-upon return on common equity took into consideration the impact of changing economic conditions on CWSS's customers. Witness Craig testified that he was not aware of any clear numerical basis for quantifying the impact of changing economic conditions on customers in determining an appropriate return on equity in setting rates for a public utility. Rather, he maintained that the impact of changing economic conditions nationwide is inherent in the methods and data used in his study to determine the cost of equity for utilities that are comparable to CWSS. In addition, he contended that customer testimony at the public hearings in this proceeding focused on the quality of service provided by CWSS and the amount of the proposed rate increases in the various service areas. Witness Craig observed that only one witness made a statement regarding the difficult economic times faced by all citizens of the United States, and how the company, along with all Americans, should cut costs if at all possible; however, that witness also stated that she believed in free enterprise and in a company's right to make a profit.

Further, witness Craig testified that it is not uncommon for the Public Staff and a utility to conclude that a stipulated rate of return is in the best interest of both parties. Witness Craig contended that in this proceeding, the grounds for a settlement were especially compelling given the 9.80% return on equity recently approved by the Commission for a Utilities Inc. subsidiary, Bradfield Farms Water Company, by Order issued December 18, 2012, in Docket No. W-1044, Sub 19.

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[1] Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944).

[2] Bluefield Waterworks & Impr. Co. v. Public Service Comm'n, 262 U.S. 679, 692-93 (1923).

G.S. 62-133.4, requires the Commission to fix rates for service which will enable a public utility, by sound management, to produce a fair profit for its stockholders, in view of current economic conditions, maintain its facilities and services and compete in the market for capital, and no more. This is the ultimate objective of rate making. Utilities Commission v. General Telephone Company, 281 N.C. 318, 189 S.E.2d 705 (1972). Based upon the evidence in this proceeding, the Commission is of the opinion that there is adequate evidence in the record to support the return on equity agreed to by the Parties; that such return should allow the Company to properly maintain its facilities and services; provide adequate service to its customers; and to produce a fair return thus enabling it to attract capital on terms that are fair and reasonable to its customers and investors. Consequently, the Commission finds and concludes that the return on common equity of 9.65% that was agreed to by the Parties is just and reasonable and should be approved. Furthermore, the Commission finds and concludes that the stipulated rates, the stipulated rate of return percentages, and the other provisions of the Revised Stipulation, as filed on June 24, 2013, which are incorporated herein by reference, are just and reasonable and should be approved.

IT IS, THEREFORE, ORDERED as follows:

1. That the Revised Stipulation between CWSS and the Public Staff, incorporated by reference herein, is hereby approved.

2. That the Schedule of Rates, attached hereto as Appendices A-1, A-2, and A-3, are hereby approved and deemed to be filed with the Commission pursuant to G.S. 62-138.

3. That the Schedule of Rates are hereby authorized to become effective for service rendered on and after the issuance date of this Order.

4. That the Notices to Customers, attached hereto as Appendices B-1, B-2, and B-3, shall be mailed with sufficient postage or hand delivered to all affected customers in each relevant service area, respectively, in conjunction with the next regularly scheduled billing process.

5. That the Applicant shall file the attached Certificate of Service, properly signed and notarized, not later than 10 days after the Notices to Customers are mailed or hand delivered to customers.

6. That neither the Revised Stipulation entered into and filed on June 24, 2013, nor the parts of this Order pertaining to the contents of that agreement shall be cited or treated as precedent in future proceedings.

ISSUED BY ORDER OF THE COMMISSION.
This the 30th day of August, 2013.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

fh083013.01

APPENDIX A-1
PAGE 1 OF 3

SCHEDULE OF RATES

for

CWS SYSTEMS, INC.

for providing water and sewer utility service

in

FAIRFIELD MOUNTAINS SERVICE AREA,
HIGHLAND SHORES SUBDIVISION, APPLE VALLEY,
LAUREL MOUNTAIN ESTATES (water only)

Rutherford County, North Carolina

WATER UTILITY SERVICE

Monthly Metered Water Rates:

A.	Base charge, zero usage	
	Residential:	$ 19.68
	Commercial and Other:	
	5/8" meter	$ 19.68
	3/4" meter	$ 29.52
	1" meter	$ 49.20
	1.5" meter	$ 98.40
	2" meter	$157.44
	3" meter	$295.20
	4" meter	$492.00
	6" meter	$984.00
B.	Usage charge, per 1,000 gallons	$ 7.23

Connection Charge: (tap on fee)

Laurel Mountain Estates	$ 0.00
All others	$500.00

Irrigation Meter Installation: Actual Cost

New Meter Charge:	Actual Cost
New Water Customer Charge:	$ 27.00

Reconnection Charge:

If water service cut off by utility for good cause	$ 27.00
If service discontinued at customer's request	$ 27.00

(Customers who ask to be reconnected within nine months of disconnection will be charged the base monthly charge for zero usage for the service periods they were disconnected.)

SEWER RATE SCHEDULE

Monthly Sewer Rates:

Residential:

Collection charge, per dwelling unit	$ 17.69
Treatment charge, per dwelling unit	$ 34.50
Total monthly flat rate, per dwelling unit	$ 52.19

Commercial and Other:

Minimum monthly collection and treatment charge	$ 52.19
Monthly collection and treatment charge for customers who do not take water service (per single family equivalent)	$ 52.19
Treatment charge per dwelling unit	
Small (less than 2,500 gal./mo.)	$ 39.50
Med. (2,500 to 10,000 gal./mo.)	$ 66.00
Med./O[1] (2,500 to 10,000 gal./mo.)	$131.50
Large (over 10,000 gal./mo.)	$157.50

(Note: All treatment charges are Town of Lake Lure charges. Classification of user is determined by the Town of Lake Lure.)

Collection Charge, per 1,000 gallons	$ 12.58

[1] Medium user/outside rate.

APPENDIX A-1
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Connection Charge: (tap on fee)	$550.00
New Sewer Customer Charge: (If customer also receives water service, this charge will be waived.)	$ 27.00

Reconnection Charge:

If sewer service is cut off by utility for good cause, the actual cost of disconnection and reconnection will be charged.

The utility will itemize the estimated cost of disconnecting and reconnecting service and will furnish the estimate to customer with the cut-off notice.

This charge will be waived if customer also receives water service from CWS Systems, Inc.

Customers who ask to be reconnected within nine months of disconnection will be charged the base monthly charge for zero usage for the service period they were disconnected.

OTHER MATTERS

Bills Due:	On billing date
Bills Past Due:	21 days after billing date
Returned Check Charge:	$25.00
Billing Frequency:	Shall be monthly for service in arrears
Finance Charge for Late Payment:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-778, Sub 89, on this the 30th day of August, 2013.

SCHEDULE OF RATES

for

CWS SYSTEMS, INC.

for providing water and sewer utility service

in

FAIRFIELD SAPPHIRE VALLEY SERVICE AREA

Jackson and Transylvania Counties, North Carolina

WATER UTILITY SERVICE

Monthly Metered Water Rates:

A. Base charge, zero usage

Residential	$ 18.07
Commercial and Other:	
5/8" meter	$ 18.07
3/4" meter	$ 27.11
1" meter	$ 45.18
1.5" meter	$ 90.35
2" meter	$144.56
3" meter	$271.05
4" meter	$451.75
6" meter	$903.50

B. Usage charge, per 1,000 gallons $ 8.34

Water Availability Rate: $ 8.25

Connection Charge: [1/]

All Areas Except Holly Forest XI, Holly Forest XIV, Holly Forest XV, Whisper Lake I, Whisper Lake Phases II and III, Deer Run, Lonesome Valley Phases I and II, and Chattooga Ridge

$ 0.00 per tap (recoupment of capital fee)
$400.00 per tap (tap on fee)

APPENDIX A-2
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Holly Forest XI

$2,400.00 per tap (recoupment of capital fee)
$ 400.00 per tap (tap on fee)

Holly Forest XIV

$250.00 per tap (recoupment of capital fee)
$400.00 per tap (tap on fee)

Holly Forest XV

$500.00 per tap (recoupment of capital fee)
$400.00 per tap (tap on fee)

Whisper Lake Phase I

$1,250.00 per tap (recoupment of capital fee)
$ 400.00 per tap (tap on fee)

Whisper Lake Phases II and III

$2,450.00 per tap (recoupment of capital fee)
$ 400.00 per tap (tap on fee)

Deer Run

$1,900.00 per tap (recoupment of capital fee)
$ 400.00 per tap (tap on fee)

Lonesome Valley Phases I and II

$0.00 per tap (recoupment of capital fee)
$0.00 per tap (tap on fee)

Chattooga Ridge

$0.00 per tap (recoupment of capital fee)
$0.00 per tap (tap on fee)

Irrigation Meter Installation:	Actual Cost
New Meter Charge:	Actual Cost
New Water Customer Charge:	$ 27.00

Reconnection Charge:

If water service cut off by utility for good cause	$ 27.00
If service discontinued at customer's request	$ 27.00

(Customers who ask to be reconnected within nine months of disconnection will be charged the base monthly charge for zero usage for the service periods they were disconnected.)

SEWER UTILITY SERVICE

Monthly Sewer Rates:

Residential:

Flat rate, per dwelling unit	$ 42.08

(Dwelling unit shall exclude any unit which has not been sold, rented or otherwise conveyed by the developer or contractor erecting the unit.)

Commercial and Other:

A. Minimum rate	$ 42.08
B. Customer who does not take water service (per single family equivalent)	$ 42.08
C. Base Facility Charge:	
5/8" meter	$ 18.50
3/4" meter	$ 27.75
1" meter	$ 46.25
1.5" meter	$ 92.50
2" meter	$148.00
3" meter	$277.50
4" meter	$462.50
6" meter	$925.00
D. Usage charge, per 1,000 gallons	$ 9.57

Sewer Availability Rate:	$ 9.80

APPENDIX A-2
PAGE 4 OF 5

Connection Charge: [1/]

All Areas Except Holly Forest XIV, Holly Forest XV, Deer Run and Lonesome Valley Phases I and II

$ 0.00 per tap (recoupment of capital fee)
$550.00 per tap (tap on fee)

Holly Forest XIV

$1,650.00 per tap (recoupment of capital fee)
$ 550.00 per tap (tap on fee)

Holly Forest XV

$475.00 per tap (recoupment of capital fee)
$550.00 per tap (tap on fee)

Deer Run

$1,650.00 per tap (recoupment of capital fee)
$ 550.00 per tap (tap on fee)

Lonesome Valley Phases I and II

$0.00 per tap (recoupment of capital fee)
$0.00 per tap (tap on fee)

New Sewer Customer Charge: $ 27.00
(If customer also receives water service, this charge will be waived.)

Reconnection Charge:

If sewer service is cut off by utility for good cause, the actual cost of disconnection and reconnection will be charged.

The utility will itemize the estimated cost of disconnecting and reconnecting service and will furnish the estimate to customer with the cut-off notice.

This charge will be waived if customer also receives water service from CWS Systems, Inc.

APPENDIX A-2
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Reconnection Charge (con't):

Customers who ask to be reconnected within nine months of disconnection will be charged the base monthly charge for zero usage for the service period they were disconnected.

OTHER MATTERS

Bills Due:	On billing date
Bills Past Due:	21 days after billing date
Returned Check Charge:	$25.00
Billing Frequency:	Shall be monthly for service in arrears. Availability billings semiannually in advance.
Finance Charge for Late Payment:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date.

NOTE:

[1/] The recoupment of capital portion of the connection charges shall be due and payable at such time as the main water and sewer lines are installed in front of each lot, and the tap on fee for water and sewer shall be payable upon request by the owner of each lot to be connected to the water and sewer lines. With written consent of the Company, payment of the recoupment capital portion of the connection charge may be made payable over five-year period following the installation of the water and sewer mains in front of each lot, payment to be made in such a manner and in such installments as agreed upon between lot owner and the Company, together with interest on the balance of the unpaid recoupment of capital fee from said time until payment in full at the rate of 6% per annum.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-778, Sub 89, on this the 30th day of August, 2013.

APPENDIX A-3
PAGE 1 OF 4

SCHEDULE OF RATES

for

CWS SYSTEMS, INC.

for providing water and sewer utility service

in

FAIRFIELD HARBOUR SERVICE AREA

Craven County, North Carolina

WATER UTILITY SERVICE

Monthly Metered Water Rates:

A. Base charge, zero usage

Residential	$ 9.30
Commercial and Other:	
5/8" meter	$ 9.30
3/4" meter	$ 13.95
1" meter	$ 23.25
1.5" meter	$ 46.50
2" meter	$ 74.40
3" meter	$139.50
4" meter	$232.50
6" meter	$464.00

B. Usage charge, per 1,000 gallons — $ 2.55

Water Availability Rate: — $ 3.15

Connection Charge: [1/]

All Areas Except Harbor Pointe II Subdivision

$ 335.00 per tap (recoupment of capital fee)
$ 140.00 per tap (tap on fee)

Harbor Pointe Subdivision and any area where mains have been installed after July 24, 1989

$ 650.00 per tap (recoupment of capital fee)
$ 320.00 per tap (tap on fee)

Irrigation Meter Installation:	Actual Cost
New Meter Charge:	Actual Cost
New Water Customer Charge:	$ 27.00
Reconnection Charge:	
If water service cut off by utility for good cause	$ 27.00
If service discontinued at customer's request	$ 27.00

(Customers who ask to be reconnected within nine months of disconnection will be charged the base monthly charge for zero usage for the service periods they were disconnected.)

SEWER UTILITY SERVICE

Monthly Sewer Rates:

Residential:	
Flat rate per dwelling unit	$ 36.70
Commercial and Others:	
A. Customers who do not take water service	
Flat monthly rate	$ 36.70
B. Monthly Metered Rates:	
Base charge, zero usage	
5/8" meter	$ 9.85
3/4" meter	$ 14.78
1" meter	$ 24.63
1.5" meter	$ 49.25
2" meter	$ 78.80
3" meter	$147.75
4" meter	$246.25
6" meter	$492.50

C. Usage charge, per 1,000 gallons $ 5.46

Sewer Availability Rate: $ 2.55

Connection Charge: [1/]

All Areas Except Harbor Pointe II Subdivision

$ 735.00 per tap (recoupment of capital fee)
$ 140.00 per tap (tap on fee)

Harbor Pointe Subdivision and any area where mains have been installed after July 24, 1989

$2,215.00 per tap (recoupment of capital fee)
$ 310.00 per tap (tap on fee)

New Sewer Customer Charge: $ 27.00
(If customer also receives water service, this charge will be waived.)

Reconnection Charge:

If sewer service is cut off by utility for good cause, the actual cost of disconnection and reconnection will be charged.

The utility will itemize the estimated cost of disconnecting and reconnecting service and will furnish the estimate to customer with the cut-off notice.

This charge will be waived if customer also receives water service from CWS Systems, Inc.

Customers who ask to be reconnected within nine months of disconnection will be charged the base monthly charge for zero usage for the service period they were disconnected.

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PAGE 4 OF 4

OTHER MATTERS

Bills Due:	On billing date
Bills Past Due:	21 days after billing date
Returned Check Charge:	$25.00
Billing Frequency:	Shall be monthly for service in arrears. Availability billings semi-annually in advance.
Finance Charge for Late Payment:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date.

NOTE:

1/ The recoupment of capital portion of the connection charges shall be due and payable at such time as the main water and sewer lines are installed in front of each lot, and the tap on fee for water and sewer shall be payable upon request by the owner of each lot to be connected to the water and sewer lines. With written consent of the Company, payment of the recoupment capital portion of the connection charge may be made payable over five year period following the installation of the water and sewer mains in front of each lot, payment to be made in such a manner and in such installments as agreed upon between lot owner and the Company, together with interest on the balance of the unpaid recoupment of capital fee from said time until payment in full at the rate of 6% per annum.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-778, Sub 89, on this the 30th day of August, 2013.

APPENDIX B-1
PAGE 1 of 2

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-778, SUB 89

In the Matter of		
Application by CWS Systems, Inc., 2335 Sanders Road, Northbrook, Illinois, for Authority to Increase Rates for Water and/or Sewer Utility Service in Fairfield Harbour, Fairfield Mountains, and Sapphire Valley in Craven, Rutherford, Jackson, and Transylvania Counties, North Carolina	)	**NOTICE TO CUSTOMERS**

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission has issued an Order authorizing CWS Systems, Inc., to charge increased rates for water and sewer utility service in its Fairfield Mountains Service Area, Highland Shores Subdivision, Apple Valley, and Laurel Mountain Estates (water only) in Rutherford County, North Carolina. The new approved rates are as follows:

FAIRFIELD MOUNTAINS SERVICE AREA,
HIGHLAND SHORES SUBDIVISION, APPLE VALLEY,
LAUREL MOUNTAIN ESTATES (water only)
(Rutherford County)

WATER UTILITY SERVICE

Monthly Metered Water Rates:

Base charge, zero usage	
Residential	$ 19.68
Commercial and Other:	
5/8” meter	$ 19.68
3/4” meter	$ 29.52
1” meter	$ 49.20
1.5” meter	$ 98.40
2” meter	$157.44
3” meter	$295.20
4” meter	$492.00
6” meter	$984.00
Usage charge, per 1,000 gallons	$ 7.23

APPENDIX B-1
PAGE 2 OF 2

SEWER UTILITY SERVICE

Monthly Sewer Rates:

Residential:

Collection charge/dwelling unit	$ 17.69
Treatment charge/dwelling unit	$ 34.50
Total monthly flat rate/dwelling unit	$ 52.19

Commercial and Other:

Minimum monthly collection and treatment charge	$ 52.19
Monthly collection and treatment charge for customers who do not take water service (per single family equivalent)	$ 52.19
Treatment charge per dwelling unit	
Small (less than 2,500 gallons per month)	$ 39.50
Med. (2,500 to 10,000 gallons per month)	$ 66.00
Med./O (2,500 to 10,000 gallons per month)	$131.50
Large (over 10,000 gallons per month)	$157.50

(Note: All treatment charges are Town of Lake Lure charges. Classification of user is determined by the Town of Lake Lure.)

Collection Charge, per 1,000 gallons	$ 12.58

Reconnection Charge:

Customers who ask to be reconnected within nine months of disconnection will be charged the base monthly charge for zero usage for the service period they were disconnected.

Returned Check Charge: $ 25.00

ISSUED BY ORDER OF THE COMMISSION.
This the 30th day of August, 2013.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

APPENDIX B-2
PAGE 1 OF 2

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-778, SUB 89

In the Matter of Application by CWS Systems, Inc., 2335 Sanders Road, Northbrook, Illinois, for Authority to Increase Rates for Water and/or Sewer Utility Service in Fairfield Harbour, Fairfield Mountains and Sapphire Valley in Craven, Rutherford, Jackson and Transylvania Counties, North Carolina	)))))))	**NOTICE TO CUSTOMERS**

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission has issued an Order authorizing CWS Systems, Inc., to charge increased rates for water and sewer utility service in its Fairfield Sapphire Valley Service Area in Jackson and Transylvania Counties, North Carolina. The new approved rates are as follows:

FAIRFIELD SAPPHIRE VALLEY SERVICE AREA
(Jackson and Transylvania Counties)

WATER UTILITY SERVICE

Monthly Metered Water Rates:

Base charge, zero usage	
Residential	$ 18.07
Commercial and Other	
5/8” meter	$ 18.07
3/4” meter	$ 27.11
1” meter	$ 45.18
1.5” meter	$ 90.35
2” meter	$144.56
3” meter	$271.05
4” meter	$451.75
6” meter	$903.50
Usage charge, per 1,000 gallons	$ 8.34
Water Availability Rate:	$ 8.25

APPENDIX B-2
PAGE 2 OF 2

SEWER UTILITY SERVICE

Monthly Sewer Rates:

Residential	
Flat rate per dwelling unit	$ 42.08

(Dwelling unit shall exclude any unit which has not been sold, rented or otherwise conveyed by the developer or contractor erecting the unit.)

Commercial and Other:	
Minimum rate	$ 42.08
Customer who does not take water service (per single family equivalent)	$ 42.08
Base Facility Charge:	
5/8” meter	$ 18.50
3/4” meter	$ 27.75
1” meter	$ 46.25
1.5” meter	$ 92.50
2” meter	$148.00
3” meter	$277.50
4” meter	$462.50
6” meter	$925.00
Usage charge, per 1,000 gallons	$ 9.57
Sewer Availability Rate:	$ 9.80

Reconnection Charge:

Customers who ask to be reconnected within nine months of disconnection will be charged the base monthly charge for zero usage for the service period they were disconnected.

Returned Check Charge: $ 25.00

ISSUED BY ORDER OF THE COMMISSION.
This the 30th day of _August_, 2013.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

APPENDIX B-3
PAGE 1 OF 2

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-778, SUB 89

In the Matter of		
Application by CWS Systems, Inc., 2335 Sanders Road, Northbrook, Illinois, for Authority to Increase Rates for Water and/or Sewer Utility Service in Fairfield Harbour, Fairfield Mountains and Sapphire Valley in Craven, Rutherford, Jackson, and Transylvania Counties, North Carolina	)	**NOTICE TO CUSTOMERS**

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission has issued an Order authorizing CWS Systems, Inc., to charge increased rates for water and sewer utility service in its Fairfield Harbour Service Area in Craven County, North Carolina. The new approved rates are as follows:

FAIRFIELD HARBOUR SERVICE AREA
(Craven County)

WATER UTILITY SERVICE

Monthly Metered Water Rates:

Base charge, zero usage	
Residential	$ 9.30
Commercial and Other:	
5/8” meter	$ 9.30
3/4” meter	$ 13.95
1” meter	$ 23.25
1.5” meter	$ 46.50
2” meter	$ 74.40
3” meter	$139.50
4” meter	$232.50
6” meter	$464.00
Usage charge, per 1,000 gallons	$ 2.55
Water Availability Rate:	$ 3.15

APPENDIX B-3
PAGE 2 OF 2

SEWER UTILITY SERVICE

Monthly Sewer Rates:

Residential	
Flat rate per dwelling unit	$ 36.70
Commercial and Others:	
Customers who do not take water service	
Flat monthly rate	$ 36.70
Monthly Metered Rates:	
Base charge, zero usage	
5/8” meter	$ 9.85
3/4” meter	$ 14.78
1” meter	$ 24.63
1.5” meter	$ 49.25
2” meter	$ 78.80
3” meter	$147.75
4” meter	$246.25
6” meter	$492.50
Usage charge, per 1,000 gallons	$ 5.46
Sewer Availability Rate:	$ 2.55

Reconnection Charge:

Customers who ask to be reconnected within nine months of disconnection will be charged the base monthly charge for zero usage for the service period they were disconnected.

Returned Check Charge: $ 25.00

ISSUED BY ORDER OF THE COMMISSION.
This the 30th day of August , 2013.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

DOCKET NO. W-1282, SUB 10

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Pluris, LLC For Authority to Pledge Utility Assets Pursuant to G.S. 62-160 *et seq.* to Secure Loan	))))	ORDER GRANTING AUTHORITY TO PLEDGE ASSETS TO SECURE LOAN

BY THE COMMISSION: On July 1, 2013, Pluris, LLC ("Pluris" or "Company") filed an Application pursuant to G.S. 62-160 *et seq.*, and Commission Rule R1-16 for permission to pledge utility assets to secure a loan in the amount of $7.7 million from the Marine Federal Credit Union in Jacksonville, North Carolina.

Based upon the verified Application and the Commission's entire files and records in this matter, the Commission now makes the following

FINDINGS OF FACT

1. Pluris is a public utility operating in North Carolina providing sewer utility service to the public for compensation. As of December 31, 2012, Pluris provided wastewater utility service to a total of 3,719 customers in Sneads Ferry and North Topsail Island, North Carolina, including 3,577 residential flat-rate customers and 142 metered commercial customers. The Company‘s address is 2100 McKinney Avenue, Suite 1550, Dallas, Texas 75201.

2. Pluris has entered into a commitment agreement executed March 27, 2013, to borrow up to $7.7 million from Marine Federal Credit Union in Jacksonville, North Carolina. The loan will be structured on a twenty-five (25) year amortization plan and the loan term will be seven (7) years. The interest rate will be fixed at 3.99% per annum for the initial 7-year term of the loan. Proceeds of the loan will be used solely to pay off and replace two existing loans with a combined current balance of $7.7 million from American Security Bank in Palmdale, California. The two loans from American Security Bank, each in the amount of $4 million for a total of $8 million, were initiated in December 2009, and December 2010, respectively. Brian L. Pratt is a Guarantor for both existing loans.

3. The loan from the Marine Federal Credit Union will be secured by a first lien deed of trust on real estate and first priority security interest and UCC lien on personal property, in form and substance satisfactory to the lender, covering all utility plant, both real and personal property of Pluris, and a first priority assignment of all Pluris' rights, title and interest in and to all accounts receivables, current and future leases, rents and profits relating to the Company's property. Pluris Holdings, LLC and Brian L. Pratt are Guarantors of the loan agreement.

4. Pluris submitted the following exhibits and information In support of the Company's Application:

Exhibit A Commitment Agreement executed March 27, 2013, between Pluris and Marine Federal Credit Union.

Exhibit B Purposes for which the $8 million American Security Bank proceeds were incurred.

Exhibit C Schedule of estimated expenses and closing costs to be incurred in conjunction with the financing transaction and pledging of assets.

Exhibit D Calculation of interest rate and embedded debt cost.

Exhibit E Latest review report of financial statements for Pluris by CJN&W Certified Public Accountants, P.A., for the fiscal years ended December 31, 2012, and 2011.

Exhibit F In-house profit and loss statement for Pluris for the three-month period ended December 31, 2012, which includes the last quarter for which an in-house profit and loss statement has been prepared.

Exhibit G Balance sheet for Pluris dated December 31, 2012, which is the latest quarter for which an in-house balance sheet has been prepared.

Exhibit H Proforma in-house balance sheet for the 12 months ending December 31, 2013, reflecting the effects of the financing.

Exhibit I Proforma in-house profit and loss statement for Pluris for the 12 months ending December 31, 2013, which reflects the effects of the financing.

Exhibit J Proforma cash flow statement for the 12 months ending December 31, 2013, which reflects the effects of the financing.

5. In the Application, Pluris acknowledged that the Commission, if it approves the proposed loan and pledging of assets, retains the right to review and adjust, if the Commission deems it appropriate to do so, the Company’s cost of capital and/or expense levels for ratemaking purposes in the Company’s next general rate case.

6. Pursuant to G.S. 62-160 *et seq.,* and Commission Rule R1-16, Pluris asserts that the financing plan and pledging of assets applied for herein (i) are for lawful objects within the corporate purposes of the Company as a public utility; (ii) are compatible with the public interest; (iii) are necessary, appropriate and consistent with the proper performance by Pluris of its service to the public; (iv) will not impair the Company’s ability to perform that service; and (v) are reasonably necessary and appropriate for the purposes for which issued.

WHEREUPON, the Commission now reaches the following

CONCLUSIONS

Based upon the foregoing Findings of Fact and the entire record in this proceeding, the Commission is of the opinion and so finds and concludes that the transactions proposed herein:

(i) Are for lawful objects within the corporate purposes of the Company as a public utility;

(ii) Are compatible with the public interest;

(iii) Are necessary, appropriate and consistent with the proper performance by the Company of its service to the public as a utility;

(iv) Will not impair the Company's ability to perform its public utility service; and

(v) Are reasonably necessary and appropriate for the purposes for which issued.

IT IS, THEREFORE, ORDERED that Pluris, LLC is hereby authorized, empowered and permitted to implement and execute the proposed financing plan and pledging of assets in accordance with the terms thereof as set forth in the Application and Exhibits appended thereto.

IT IS FURTHER ORDERED that the Commission's approval in this docket does not restrict the Commission's regulatory authority to review and adjust, if the Commission deems it appropriate to do so, the Company's cost of capital and/or expense levels for ratemaking purposes in the Company's next general rate case.

ISSUED BY ORDER OF THE COMMISSION.
This the 12th day of July, 2013.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

mr071213.01

DOCKET NO. WR-354, SUB 3

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Julie Morgan, 8514 Cozumel St. #57, Charlotte, North Carolina 28227, *et al.*, Complainants v. Woodward Communities, LLC, and Woodward Village, Respondents	ORDER APPROVING RECOMMENDATIONS, REQUIRING MODIFICATIONS TO BILLS AND REFUNDS OF OVERCHARGES

BY THE COMMISSION: On February 28, 2012, Julie Morgan and seven other residents of Woodward Village Mobile Home Park (collectively Complainants), filed individual complaints against Woodward Communities, LLC, and Woodward Village (collectively Respondents), alleging unfair billing practices with respect to the Complainants' water and sewer service.

On March 6, 2012, the Commission issued an Order Consolidating Complaints and Serving Complaints in the above-captioned proceeding.

On March 22, 2012, the Respondents requested more time to file an Answer by electronic mail (e-mail). This request was granted by Order of the Commission on March 23, 2012.

On March 30, 2012, the Respondents filed their Answer to the Complaint.

On April 3, 2012, the Commission issued its Order Serving Answer.

On April 16, 2012, the Complainants filed a Motion requesting an Extension of Time to File a Reply until April 23, 2012. The Complainants' motion was granted by Order of the Commission that same day.

On April 23, 2012, the Complainants made a filing in the docket informing the Commission that they were not satisfied with the Respondents' Answer and requesting a hearing.

On May 15, 2012, the Commission issued an Order Denying Hearing and Requesting the Public Staff Investigate. In the Order, the Commission, among other things, requested that the Public Staff – North Carolina Utilities Commission (Public Staff) conduct an investigation into this complaint proceeding, submit a written report of its findings to the Commission, and make a recommendation as to how the Commission should proceed. The Public Staff was to submit its report no later than June 30, 2012.

On June 29, 2012, the Public Staff filed a Motion for Extension of Time to file its Report. On July 2, 2012, the Commission issued an Order Granting Extension of Time allowing the Public Staff until July 3rd to make its filing.

On July 3, 2012, the Public Staff filed its report with the Commission setting forth its findings relating to the issues raised by the Complainants. The Public Staff also provided several recommendations addressing issues identified by the Complainants.

On July 6, 2012, the Commission issued an Order Serving Public Staff Report. The Order allowed each party until July 24th to review and provide comments to the Commission. No comments were received from the parties regarding the Public Staff's report.

On December 19, 2012, the Commission filed in the docket an e-mail correspondence from Complainant to the Public Staff's Consumer Services Division.

On December 21, 2012, the Commission issued an Order Serving Correspondence and Requesting Response.

On January 2, 2013, the Respondents filed a Motion for Extension of Time, which was granted by Order of the Commission on January 3rd.

On January 17, 2013, the Respondents filed their Answer to the Complainant's e-mail correspondence.

On January 28, 2013, the Commission issued an Order Serving the Respondents Answer to the Complainant's e-mail correspondence.

In preparation for its investigation, the Public Staff reviewed the initial filing and subsequent filings in the docket. After conducting this review, the Public Staff noted that the Complainants voiced six concerns regarding their utility bills and the charges contained therein. These six enumerated concerns are outlined as follows:

(1) Information provided on the water and sewer bills is not in accordance with G.S. 62-110(1a)(e);

(2) The water and sewer bills state, in violation of G.S. 42-46(d) that rent payments will not be accepted without water and sewer payment included;

(3) The Complainants are being charged late fees for failing to pay water and sewer bills;

(4) Readings on water and sewer bills do not match up with the meters on the mobile homes;

(5) The Respondents have not provided customers the information required by Commission Rule R18-7(f), regarding the Company's business office at Woodward Village; and

(6) Bills for the past three years should be audited and overpayments, if any, should be refunded because Respondents have been overcharging for water and sewer utility service.

The Public Staff made the following recommendations to address the Complainants' concerns.

The first concern raised by the Complainants involved the information included on their water and sewer bills. According to the Complainants, the information does not comply with G.S. 62-110(g)(1a)(e) and thus violates North Carolina law and Commission Rules. However, the Public Staff's investigation found that the Complainants' reliance on G.S. 62-110(g)(1a)(e)[1] to support their contention that the Respondents' practices do not comply with North Carolina Law and Commission Rules is misplaced.

According to the Public Staff, the information contained on the Complainant's water and sewer bills is governed by Commission Rules R7-23 and R10-19, rather than G.S. 62-110(g)(1a)(e) because the Respondents meter the customers total water consumption and do not use the "hot water capture, cold water allocation" (HWCCWA) metering method. When reviewed under the appropriate criteria, the Respondents' old and new bills were in compliance with Rule R7-23. However, neither the Respondents' old nor their new bills included the price of sewer service per unit of consumption as required by Rule R10-19(1).[2] The Public Staff is confident that the information can be included on subsequent bills. Therefore, the Public Staff recommended that the "unit price for water usage" also be shown on the bill, although it is not required by Rule R7-23. The Public Staff also recommended that the administrative fee[3] also be shown as a separate line item.

The second concern investigated by the Public Staff was the allegation that Respondents would not accept rent payments without water and sewer payments included. During its review of the Complainants' bills, the Public Staff recognized inconsistencies in Respondents' practice of imposing late fees on late water and sewer or not accepting rent payment without the corresponding utility payment. The Public Staff observed that Respondents' standard bill form stated that "Rent will not be accepted unless water is included." According to the Public Staff, this language is contrary to established law and Commission policy.[4] The Public Staff notes that G.S. 42-42.1(b), G.S. 42-42.1(b) and Commission Rule R18-7 prohibit the imposition of late fees, refusal to accept rent without an accompanied water or sewer payment, taking termination actions against a tenant's water or sewer service and/or evicting a tenant for failure to pay these charges. Because of this, the Public Staff recommended that the Respondents be directed to accept rental payment without regard to what a tenant may owe for water or sewer service.

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[1] G.S. 62-110(g)(1a)(e) lists the information to be provided on bills by water and sewer resellers who use the "hot water capture, cold water allocation" (HWCCWA) metering method. The Respondents do not use the HWCCWA method, but instead meter the customer's total water consumption.

[2] Under Commission Rule R10-19(1), sewer bills must include "the price per unit" of the service supplied.

[3] Respondents charge a $3.75 monthly administrative fee to each customer.

[4] *See* G.S. 42-42.1 etc for support.

The third issue raised in this complaint was that the Complainants were being charged late fees for failure to pay their water and sewer bills. A review of the Respondents' accounts revealed that the Complainants' concerns in this regard were well founded. That is, some of the bills that were reviewed showed that there were outstanding amounts due for water service. According to the Public Staff, this could be easily interpreted as imposing late fees for nonpayment of water charges, in violation of Rule R18-7(a). To remedy this, the Public Staff recommended that the Respondents be directed to comply with Commission Rules and not impose late fees for nonpayment of water and sewer charges.

The fourth issue raised by the Complainants was the allegation that readings on the water bills did not match up with the meters on the mobile homes. The Public Staff took several steps to assess and address this concern. First, the Public Staff made a site visit to the mobile home park on June 27, 2012. Although, the Public Staff did not inspect meters at every mobile home site for a variety of reasons, the Public Staff found that when meter inspections were made, the meter boxes, regardless of age, were found to be functioning properly and within standards. Second, the Public Staff also reviewed water meter readings and usage patterns for each resident over the past three years. Based upon this review, the Public Staff found that, in general, the usage patterns are in line with what might be expected in a mobile home community. Finally, the Public Staff also noted that the Respondents have been responsive to the Complainants' concerns when bills run high. That is, the Public Staff noted that when usage was high, the Respondents reread the meter, checked for leaks and/or asked tenants to check for leaks. Where meters were broken, the Respondents estimated bills, or did not charge for usage.

The fifth issue raised by the Complainants is their contention that the Respondents have not made rate information available to the residents as required by Commission rules. The Public Staff found merit in this contention. During its investigation, the Public Staff learned that, in the past, the Respondents provided the rate information to customers when, the customer moved into the residence and the rate information was also posted on the wall of the Respondents' business office. However, the Public Staff also learned that the information posted on the wall was not a copy of the Commission approved rate schedule, but a somewhat inaccurate description of the rates. As a result, the Public Staff recommended that the Respondents be ordered to comply fully with the requirements of Commission Rule R18-7(f).[1]

The final issue investigated by the Public Staff involves the Complainants' allegation that they have been overcharged for water and sewer service by the Respondents and their request that their bills for the last three years be audited. The Complainants further requested that the Commission order the Respondents to refund overcharges if any overcharges are confirmed.

The Public Staff has reviewed the Respondents' water usage and billing records for three years and it appears that the rates collected each month have been higher than the rates permitted

[1] Commission Rule R18-7(f) requires that every provider shall provide to each customer at the time the lease agreement is signed, and shall maintain in its business office, in public view, near the place where payments are received, … a copy of rates, rules and regulations applicable to the premises…a copy of these rules and regulations…a statement advising tenants…they may contact the Commission either by Calling the Public Staff-North Carolina Utilities Commission….

under the rate schedule most recently approved by the Commission for the great majority of customers.

According to the Public Staff, there were three main reasons for the differences between the Commission-approved rates and the rates actually collected by the Respondents. First, the Respondents did not adhere to the rate schedule approved by the Commission on October 9, 2007, in Docket No. WR-354, Sub 1, which allows the Respondents to collect $1.78 per thousand gallons for water service, $4.30 per thousand gallons for sewer service, and a $3.75 monthly administrative fee. Second, as shown on Exhibit 3 to their answer, the Respondents routinely rounded customer usage up to the next higher thousand gallons when calculating bills. This rounding procedure, which increases the customer's bill, is not authorized by Commission rules. Third, after the customer's final bill was calculated, the Respondents rounded it down to the next dollar. While rounding down in this manner is favorable to the customer, it is not permitted by the Commission rules.

The Public Staff estimated that over the three-year period from June 2009 through May 2012, the Respondents' actual bills to customers exceeded the rates that should have been collected under the rate schedule approved in Docket No. WR-354, Sub 1, by approximately $28,000. Since the overcharges affected all customers, not just the eight original Complainants, the Public Staff recommended that it is appropriate for refunds to be made to all customers. The Public Staff thus recommended that the Respondents be required to review the Public Staff's calculations, provide any needed corrections, and file a refund plan with the Commission within two weeks. The refunds should include payments to all of the Respondents' customers during the past three years, except for customers whose current address cannot be determined without substantial difficulty because they have moved out of Woodward Village Mobile Home Park.

WHEREUPON, the Commission finds the following

CONCLUSIONS

The Respondents have acknowledged in their Answer that their water and sewer bills did not fully comply with the applicable statutes and Commission rules. According to the Respondents, these violations were due to management inexperience rather than an intentional disregard of the Commission's requirements. The Respondents asserted that they had adopted a new bill format in an effort to bring the water and sewer bills into compliance with the applicable statutes and rules.

The Commission further learned from the Public Staff that the Respondents have made some changes to their billing information and procedures since the filing of the complaints. More specifically, the Respondents have revised their bills so that they are now in compliance with Commission Rule R18-7(d).[1]

[1] Commission Rule R18-7(d) states: "The date after which a bill for water or sewer utility service is due, or the past due after date, shall be disclosed on the bill and shall not be less than twenty-five (25) days after the billing date."

The Respondents have also changed their billing cycle to comply with the Commission's rules. However, this change maintains the due date on the first of the month when rental payments are due. Previously, the Respondents had been reading the meters around the 15th of each month, with the due date on the first of the following month, providing only an interval of about 15 days between the billing date and due date. According to the Public Staff, meter readings are now taken at the end of the month, with the bills being rendered at the start of the new month, and the due date falling on the first day of the next month. To establish this new billing cycle, the billing cycle was shortened to two weeks for one billing period. Since then, the billing cycle has returned to monthly.

The Commission has also reviewed the Public Staff's recommendations and concurs with the Public Staff's position on these issues. The Commission finds these recommendations reasonable and believes that they will provide some clarity to the Complainants. The Commission has further reviewed the Public Staff's findings and considered the law and determines, that such actions are consistent with the law and will further encourage compliance with the law and well established Commission Rules. Therefore, the Commission finds good cause to accept the Public Staff's recommendations in this matter.

IT IS, THEREFORE, ORDERED as follows:

1. That the Respondents show the per-1,000 gallon unit water and sewer usage charges on the monthly water and sewer bill, and also show the monthly administrative fee as a separate line item;

2. That the Respondents accept rent payments without regard to what a customer owes on a water or sewer bill;

3. That the Respondents comply with Commission Rule R18-7(a) by not imposing late fees for nonpayment of water or sewer charges;

4. That the Respondents comply with the requirements of Commission Rule R18-7(f) by providing to all customers, and posting in the business office, the Commission-approved rate schedule and the full text of Chapter 18 of the Commission Rules, Provision of Water and Sewer Services by Landlords;

5. That the Respondents charge only the Commission-approved rates without rounding usage to the next higher 1,000 gallons, or reducing the final total charge to the next lower dollar; and

6. That the Respondents review the Public Staff's calculations, provide any needed corrections, calculate the refund owed to each individual customer, and file a refund plan with the Commission, within 30 days after issuance of the Commission's order. Refunds should be calculated in accordance with the following requirements:

a. Refunds shall be calculated for each mobile home and each customer, except for customers who have moved out of Woodward Village Mobile Home Park and whose current address cannot be determined without substantial difficulty.

b. The refund period shall begin with bills payable in July 2009 or the month the customer moved into the mobile home park, whichever is later, and extends through bills payable in June 2012.

c. For each customer and each month of the refund period, Respondents shall calculate the amount that properly should have been billed to the customer. This should be done by multiplying the customer's metered usage (without rounding up) by the Commission-approved rate of $6.08 per thousand gallons ($1.78 for water and $4.30 for sewer) and adding the $3.75 administrative fee.

d. For each customer and each month of the refund period, the amount that should have been billed to the customer should be subtracted from the amount actually billed, so as to determine the overcharge for the month.

e. For each month and each customer, the monthly overcharges should be summed to arrive at the total refund due to the customer.

f. Respondents shall submit to the Commission a refund plan showing the total amount of the refund due to each customer, how the refund was calculated, and how Respondents plan to ensure that each customer receives a check for the amount to which the customer is entitled. (The Commission understands that the Respondents have already begun to make refunds to its customers in response to the Public Staff's recommendations filed with the Commission on July 3, 2012. The Commission seeks information regarding these refunds and any others still pending in this docket.)

ISSUED BY ORDER OF THE COMMISSION.
This the 19th day of February, 2013.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

Pb021913.01

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Albemarle Solar Center, LLC	SP-2332, SUB 0	(01/24/2013)
Amethyst Solar, LLC	SP-2524, SUB 0	(07/30/2013)
Angel Solar, LLC	SP-2777, SUB 0	(09/17/2013)
Angier Farm, LLC	SP-2301, SUB 0	(01/24/2013)
Ashley Solar Farm, LLC	SP-2736, SUB 0	(07/30/2013)
Audrey Solar, LLC	SP-2218, SUB 0	(02/13/2013)
Austin Solar, LLC	SP-2778, SUB 0	(09/24/2013)
Bailey Farm, LLC	SP-2300, SUB 0	(01/24/2013)

ORDERS AND DECISIONS LISTED

ORDER ISSUING CERTIFICATE AND ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY

Orders Issued *(Continued)*

Company	Docket No.	Date
Battleground Solar I, LLC	SP-2346, SUB 0	(02/26/2013)
Bearpond Solar Center, LLC	SP-2313, SUB 0	(01/24/2013)
Binks Solar, LLC	SP-2679, SUB 0	(07/16/2013)
Bladenboro Farm, LLC	SP-2296, SUB 0	(01/24/2013)
Bladenboro Farm 2, LLC	SP-2921, SUB 0	(11/15/2013)
Bolton Farm, LLC	SP-2235, SUB 0	(01/24/2013)
Boseman Solar Center, LLC	SP-2334, SUB 0	(04/30/2013)
BRE NC Solar 1, LLC	SP-2930, SUB 0	(11/27/2013)
Brenden Solar, LLC	SP-2542, SUB 0	(07/16/2013)
Broadway Solar Center, LLC	SP-2290, SUB 0	(01/24/2013)
Buddy Solar, LLC	SP-2541, SUB 0	(07/02/2013)
Carolina Solar Energy II, LLC	SP-2363, SUB 2	(04/23/2013)
Carthage Farm, LLC	SP-2443, SUB 0	(03/18/2013)
Charlotte Solar, LLC	SP-2568, SUB 0	(05/15/2013)
Chauncey Farm, LLC	SP-1909, SUB 0 SP-1909, SUB 1	(01/24/2013)
Colin Solar, LLC	SP-2543, SUB 0	(06/04/2013)
Cooleemee Farm, LLC	SP-2432, SUB 0	(04/23/2013)
Cornwall Solar Center, LLC	SP-2297, SUB 0	(01/24/2013)
DD Fayetteville Solar NC, LLC	SP-2302, SUB 0	(12/04/2013)
DEGS NC Solar, LLC	SP-2357, SUB 0	(03/18/2013)
Dellenger Catawba Farm, LLC	SP-2946, SUB 0	(12/04/2013)
Dessie Solar Center, LLC	SP-2312, SUB 0	(01/29/2013)
Duck Solar, LLC	SP-2564, SUB 0	(05/15/2013)
Dunlap Farm, LLC	SP-2707, SUB 0	(07/09/2013)
Duplin Solar II, LLC	SP-2682, SUB 0	(05/15/2013)
Eastover Farm, LLC	SP-2289, SUB 0	(01/24/2013)
Elliana Solar, LLC	SP-2216, SUB 0	(06/04/2013)
Elmwood Solar, LLC	SP-2509, SUB 0	(06/26/2013)
Elroy Farm, LLC	SP-2922, SUB 0	(11/15/2013)
Enfield Farm, LLC	SP-2708, SUB 0	(07/16/2013)
Erwin Farm, LLC	SP-2709, SUB 0	(07/09/2013)
Eubanks Solar Farm, LLC	SP-2990, SUB 0	(12/04/2013)
Flash Solar, LLC	SP-2558, SUB 0	(07/16/2013)
Flemming Solar Center, LLC	SP-2333, SUB 0	(01/24/2013)
FLS Solar 100, LLC	SP-2280, SUB 0	(02/13/2013)
FLS Solar 140, LLC	SP 2485, SUB 0	(08/21/2013)
FLS Solar 200, LLC	SP-2486, SUB 0	(04/23/2013)
Fremont Farm, LLC	SP-2923, SUB 0	(11/15/2013)

ORDER ISSUING CERTIFICATE AND ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY

Orders Issued (Continued)

Company	Docket No.	Date
Fresh Air Energy – II, LLC	SP-2665, SUB 0	(09/17/2013)
	SP-2665, SUB 1	(09/17/2013)
	SP-2665, SUB 2	(09/17/2013)
	SP-2665, SUB 4	(10/15/2013)
	SP-2665, SUB 5	(10/31/2013)
	SP-2665, SUB 6	(10/31/2013)
	SP-2665, SUB 13	(12/04/2013)
	SP-2665, SUB 14	(12/18/2013)
	SP-2665, SUB 15	(12/18/2013)
Geenex, LLC	SP-2465, SUB 0	(06/26/2013)
Goldengate Farm, LLC	SP-2710, SUB 0	(07/09/2013)
GoldIvey Farm, LLC	SP-2712, SUB 0	(07/30/2013)
Graham Solar Center, LLC	SP-2309, SUB 0	(01/24/2013)
Greenville Farm	SP-2894, SUB 0	(10/31/2013)
Greenville Farm, LLC	SP-2444, SUB 0	(03/12/2013)
Harrell's Hill Solar Center, LLC	SP-2314, SUB 0	(01/24/2013)
Hawkins Solar, LLC	SP-2690, SUB 0	(07/16/2013)
Holiday Farm, LLC	SP-2714, SUB 0	(07/30/2013)
Jaren Solar, LLC	SP-2157, SUB 0	(01/24/2013)
Katherine Solar, LLC	SP-2569, SUB 0	(06/04/2013)
Kenansville Solar Farm, LLC	SP-2410, SUB 0	(06/26/2013)
Laurel Hill Farm, LLC	SP-2713, SUB 0	(07/09/2013)
Laurinburg Farm, LLC	SP-2459, SUB 0	(04/02/2013)
Littlefield Solar Center, LLC	SP-2336, SUB 0	(01/24/2013)
Market Farm, LLC	SP-2471, SUB 0	(04/09/2013)
Mayodan Farm, LLC	SP-2895, SUB 0	(10/31/2013)
McCallum Farm, LLC	SP-2196, SUB 0	(01/02/2013)
McKenzie Farm, LLC	SP-2372, SUB 0	(01/29/2013)
Miles Solar, LLC	SP-2565, SUB 0	(05/15/2013)
Monroe Farm, LLC	SP-2711, SUB 0	(07/30/2013)
Montgomery Solar, LLC	SP-2453, SUB 0	(04/23/2013)
Myrick Farm, LLC	SP-2715, SUB 0	(11/27/2013)
Nash 58 Farm, LLC	SP-2292, SUB 0	(01/24/2013)
Nash 64 Farm, LLC	SP-2293, SUB 0	(01/24/2013)
		(07/30/2013)
Ostrich Farm, LLC	SP-2896, SUB 0	(10/31/2013)
Owen Solar, LLC	SP-2156, SUB 0	(03/05/2013)
Parmele Farm, LLC	SP-3024, SUB 0	(12/10/2013)
Pate Farm, LLC	SP-2295, SUB 0	(01/24/2013)

ORDERS AND DECISIONS LISTED

ORDER ISSUING CERTIFICATE AND ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY

Orders Issued *(Continued)*

Company	Docket No.	Date
Progress Solar I, LLC	SP-1604, SUB 0	(03/05/2013)
Rams Horn Solar Center	SP-2338, SUB 0	(01/24/2013)
Red Hill Solar Center, LLC	SP-2291, SUB 0	(01/29/2013)
Red Springs Farm, LLC	SP-2371, SUB 0	(02/13/2013)
Redding Solar Farm, LLC	SP-2721, SUB 0	(07/09/2013)
Redmon Solar Farm, LLC	SP-2662, SUB 0	(06/26/2013)
RJ Solar, LLC	SP-2572, SUB 0	(07/02/2013)
Samarcand Solar Farm, LLC	SP-2356, SUB 0	(05/21/2013)
Shadow Solar, LLC	SP-2567, SUB 0	(05/15/2013)
Shankle Solar Center, LLC	SP-2311, SUB 0	(01/24/2013)
Sigmon Catawba Farm, LLC	SP-2703, SUB 0	(07/09/2013)
SoINCPower1, LLC	SP-2910, SUB 0	(12/04/2013)
	SP-2910, SUB 1	(10/31/2013)
	SP-2910, SUB 2	(10/31/2013)
	SP-2910, SUB 3	(12/04/2013)
Soluga Farms I, LLC	SP-2462, SUB 0	(04/23/2013)
Soluga Farms II, LLC	SP-2463, SUB 0	(06/20/2013)
Star Solar, LLC	SP-2573, SUB 0	(06/20/2013)
Stout Farm, LLC	SP-2897, SUB 0	(11/15/2013)
Sunfish Farm, LLC	SP-2924, SUB 0	(10/31/2013)
Upchurch Solar Center, LLC	SP-2335, SUB 0	(01/24/2013)
Van Slyke Solar Center, LLC	SP-2337, SUB 0	(01/24/2013)
Wadesboro Farm, LLC	SP-2374, SUB 0	(02/13/2013)
Wagstaff Farm 2, LLC	SP-2373, SUB 0	(02/13/2013)
Wall Solar Farm, LLC	SP-2972, SUB 0	(12/04/2013)
Warsaw Farm, LLC	SP-2526, SUB 0	(04/30/2013)
Webb Solar Farm, LLC	SP-2704, SUB 0	(07/09/2013)
Whiteheart Farm, LLC	SP-2705, SUB 0	(08/06/2013)
Wiggins Mill Farm, LLC	SP-2900, SUB 0	(11/15/2013)
Williamston West Farm, LLC	SP-2971, SUB 0	(12/04/2013)
Wommack Farm, LLC	SP-3025, SUB 0	(12/04/2013)
Yanceyville Farm 2, LLC	SP-2898, SUB 0	(11/15/2013)
Yanceyville Farm 3, LLC	SP-2925, SUB 0	(11/15/2013)

SMALL POWER PRODUCERS – Certificate *(Continued)*

DEGS NC Solar, LLC – SP-2357, SUB 1; Recommended Order Granting Certificate with Conditions (06/27/2013)

Greenville Farm 2, LLC -- SP 2894, SUB 0; Errata Order (11/19/2013)

McCallum Farm, LLC – SP-2196, SUB 0; Errata Order (01/02/2013)

Nash 64 Farm, LLC – SP-2293, SUB 0; Order Issuing Certificate and Accepting Registration of New Renewable Energy Facility at Changed Location (07/30/2013)

REI 2, LLC – SP-2014, SUB 0; SP-2422, SUB 0; Order Assigning New Docket Number and Closing Original Docket (01/11/2013)

SECDC, LLC – SP-2352, SUB 3; Recommended Order Granting Certificate with Conditions (07/03/2013)

SunEnergy 1, LLC – SP-751, SUB 9; Recommended Order Granting Certificate With Conditions (12/23/2013)

ORDER AMENDING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AND REGISTRATION STATEMENT

Orders Issued

Company	Docket No.	Date
Albemarle Solar Center, LLC	SP-2332, SUB 0	(06/04/2013)
Arndt Farm, LLC	SP-1381, SUB 0	(07/05/2013)
	SP-1381, SUB 1	
Belwood Farm, LLC	SP-1390, SUB 0	(06/06/2013)
	SP-1390, SUB 1	
	SP-1390, SUB 0	(07/05/2013)
	SP-1390, SUB 1	
Chadbourn Farm, LLC	SP-1767, SUB 0	(07/05/2013)
	SP-1767, SUB 1	
Dunlap Farm, LLC	SP-2707, SUB 0	(08/19/2013)
Enfield Farm, LLC	SP-2708, SUB 0	(08/20/2013)
Erwin Farm, LLC	SP-2709, SUB 0	(08/20/2013)
Flemming Solar Center, LLC	SP-2333, SUB 0	(06/05/2013)
Fuquay Farm, LLC	SP-1611, SUB 0	(07/05/2013)
Goldengate Farm, LLC	SP-2710, SUB 0	(08/22/2013)
Laurel Hill Farm, LLC	SP-2713, SUB 0	(08/22/2013)
Littlefield Solar Center, LLC	SP-2336, SUB 0	(06/05/2013)
Milo Solar, LLC	SP-1965, SUB 0	(06/21/2013)
Minnie Solar, LLC	SP-1967, SUB 0	(06/21/2013)
Mocksville Farm, LLC	SP-1613, SUB 0	(07/05/2013)
Mount Olive Farm, LLC	SP-2040, SUB 0	(10/03/2013)
Nash 64 Farm, LLC	SP-2293, SUB 0	(11/19/2013)
Raeford Farm, LLC	SP-1303, SUB 0	(07/05/2013)
	SP-1303, SUB 1	
	SP-1304, SUB 1	

ORDER AMENDING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AND REGISTRATION STATEMENT
Orders Issued *(Continued)*

Company	Docket No.	Date
Rams Horn Solar Center, LLC	SP-2338, SUB 0	(06/05/2013)
Redding Solar Farm, LLC	SP-2721, SUB 0	(08/22/2013)
Shannon Farm, LLC	SP-1304, SUB 0	(07/05/2013)
Sigmon Catawba Farm, LLC	SP-2703, SUB 0	(08/22/2013)
South Robeson Farm, LLC	SP-1290, SUB 0 SP-1290, SUB 1	(07/05/2013)
UpChurch Solar Center, LLC	SP-2335, SUB 0	(06/05/2013)
Warrenton Farm, LLC	SP-1713, SUB 0	(07/05/2013)
Watts Farm, LLC	SP-1301, SUB 0 SP-1301, SUB 1	(07/05/2013)
Webb Solar Farm, LLC	SP-2704, SUB 0	(08/19/2013)
Whiteheart Farm, LLC	SP-2705, SUB 0	(12/20/2013)

***Apple, Inc.* –** SP-1642, SUB 1; Order Amending Certificate (01/15/2013)

***Arcadia Community Solar, LLC* –** SP-2214, SUB 1; Order Canceling Registration and Closing Docket (10/04/2013)

***Avalon Hydropower, LLC* –** SP-130, SUB 1; SP-137, SUB 1 & SUB 3; Order Amending Certificate and Registration of New Renewable Energy Facility (04/26/2013)

***Chauncey Farm, LLC* –** SP-1909, SUB 0; SP-1909, SUB 1; Order Amending Certificate and Registration of New Renewable Energy Facility (09/24/2013)

***Enfield Farm, LLC* –** SP-2708, SUB 0; Second Order Amending Certificate of Public Convenience and Necessity and Registration Statement (12/19/2013)

***ENlight Solar, LLC* --** SP-2065, SUB 0; SP 2065, SUB 1; SP-2555, SUB 0; Order Amending Certificate of Public Convenience and Necessity and Accepting Registration Statement (05/31/2013)

***Holstein Holdings, LLC* –** SP-2758, SUB 0; Order Amending Certificate of Public Convenience and Necessity (11/19/2013)

***Railroad Farm 2, LLC* –** SP-1918, SUB 0; Order Amending Certificate of Public Convenience and Necessity (10/03/2013)

***Rock Farm, LLC* –** SP-1659, SUB 0; Order Amending Certificate (05/21/2013)

***Sustainable Energy Community Development, LLC, d/b/a SECDC, LLC* –** SP-2352, SUBS 4; SP-2352, SUB 6; SP-751, SUB 20; Order Transfering and Amending Certificate of Public Convenience and Necessity (08/28/2013)

ORDERS AND DECISIONS LISTED

SMALL POWER PRODUCERS -- Filings Due Per Order or Rule

ORDER ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY
Orders Issued

Company	Docket No.	Date
Adams; Sean	SP-2606, SUB 1	(12/27/2013)
Admark Graphic Systems, Inc.	SP-3050, SUB 0	(11/13/2013)
Adventure Solar, LLC	SP-2342, SUB 0	(04/11/2013)
Aiwin, LLC	SP-2252, SUB 0	(01/02/2013)
All States Medical Supply, Inc.	SP-2068, SUB 1	(04/09/2013)
Altadore Investments LLC	SP-1278, SUB 1	(04/09/2013)
Anderson Solar LLC	SP-2299, SUB 0	(02/18/2013)
Appalachian State University	SP-283, SUB 6	(04/09/2013)
	SP-283, SUB 12	(07/16/2013)
	SP 283, SUB 13	(07/16/2013)
Apple, Inc.	SP-1642, SUB 0	(04/09/2013)
Arba Solar LLC	SP-2319, SUB 0	(01/18/2013)
Arcadia Community Solar, LLC	SP-2214, SUB 1	(01/02/2013)
Bamboo Stone Properties, LLC	SP-1582, SUB 3	(04/26/2013)
Barber; Peter	SP-1287, SUB 1	(06/03/2013)
Barham; James and Julia	SP-2378, SUB 0	(04/11/2013)
Bethel Solar, LLC	SP-2538, SUB 0	(07/16/2013)
Blanco; Maria E. & William C. Black	SP-2502, SUB 1	(06/03/2013)
Burch; Warner	SP-2240, SUB 1	(01/02/2013)
Castalia Solar LLC	SP-2355, SUB 0	(02/08/2013)
CBC Alternative Energy, LLC	SP-1405, SUB 3	(12/27/2013)
Chinquapin Solar LLC	SP-2211, SUB 0	(01/02/2013)
CII Methane Management IV, LLC	SP-2101, SUB 0	(03/08/2013)
City of Charlotte	SP-1454, SUB 3	(04/26/2013)
Clean Energy, LLC	SP-2422, SUB 1	(08/09/2013)
Coastal Beverage Company, Inc.	SP-3062, SUB 0	(11/13/2013)
Colloredo; Franchesca N. & Rudolf Colloredo-Mansfield	SP-2533, SUB 1	(07/16/2013)
Columbus County	SP-1954, SUB 1	(09/11/2013)
Congolina, LLC	SP-2482, SUB 0	(04/29/2013)
Degulis; Joseph M.	SP-2513, SUB 1	(06/03/2013)
Dickerson; Alesia & Perry	SP-2224, SUB 0	(04/09/2013)
DiConcilio; Joseph & Michelle	SP-2672, SUB 1	(08/28/2013)
Dougherty; Kevin	SP-2220, SUB 0	(01/02/2013)
Duplin Solar I, LLC	SP-2316, SUB 2	(10/11/2013)
East Wayne Solar LLC	SP-2294, SUB 0	(02/08/2013)
Edenfield; George & Sharon	SP-2487, SUB 0	(04/29/2013)

ORDER ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY

Orders Issued (Continued)

Company	Docket No.	Date
Elk Park Solar, LLC	SP-1668, SUB 0	(04/09/2013)
ESA Newton Grove 1 NC, LLC	SP-1989, SUB 0	(09/11/2013)
ESA Selma NC 1, LLC	SP-2249, SUB 0	(09/11/2013)
ESA Smithfield 1 NC, LLC	SP-1988, SUB 0	(09/11/2013)
Faison Solar LLC	SP-2172, SUB 0	(02/08/2013)
FLS Solar 110, LLC	SP-2339, SUB 0	(04/11/2013)
FLS Solar 170, LLC	SP-2468, SUB 0	(02/25/2013)
FLS Solar 220, LLC	SP-2431, SUB 0	(04/29/2013)
Flying Dragon, LLC	SP-2470, SUB 1	(06/03/2013)
Franklin Solar 2 LLC	SP-2360, SUB 0	(02/08/2013)
Freirich Foods, Inc.	SP-2143, SUB 0	(01/02/2013)
Frishmuth; Chris	SP-2231, SUB 0	(01/02/2013)
Funderburk; Irwin	SP-2170, SUB 1	(04/09/2013)
Gainey Solar, LLC	SP-1980, SUB 0	(02/18/2013)
Harman; Derrell	SP-2283, SUB 0	(04/09/2013)
Hayes; Charles R.	SP-2826, SUB 1	(11/13/2013)
Hoffman and Hoffman, Inc.	SP-2104, SUB 0	(01/02/2013)
Holt; Jefferson, d/b/a Holt Family Farm Power	SP-275, SUB 1	(04/26/2013)
Howell; John I., III	SP-2119, SUB 0	(01/02/2013)
Huang; Sam	SP-2951, SUB 0	(10/02/2013)
Ideal Fastner Corporation	SP-1319, SUB 2	(01/02/2013)
Information Analytics Consulting, Inc.	SP-1520, SUB 3	(02/25/2013)
Innovative Solar II, LLC	SP-2423, SUB 1	(08/09/2013)
Innovative Solar 10, LLC	SP-2163, SUB 1	(01/02/2013)
Innovative Solar 12, LLC	SP-2152, SUB 1	(04/09/2013)
Innovative Solar 14, LLC	SP-2205, SUB 1	(01/02/2013)
Innovative Solar 15, LLC	SP-2153, SUB 1	(04/09/2013)
J. T. Hobby & Son, Inc.	SP-2347, SUB 0	(04/11/2013)
Jakana Solar, LLC	SP-2498, SUB 0	(06/05/2013)
Jewels Realty Investment, LLC	SP-631, SUB 6	(04/26/2013)
Keesee; Susan H. & David W.	SP-2343, SUB 1	(06/03/2013)
Kenansville Solar 2 LLC	SP-2233, SUB 0	(02/08/2013)
Kinston Solar LLC	SP-2318, SUB 0	(02/08/2013)
Lafayette Solar I, LLC	SP-2838, SUB 0	(10/11/2013)
Lavelle; Sara	SP-2899, SUB 0	(10/03/2013)
Lewiston Solar, LLC	SP-2499, SUB 0	(06/05/2013)
Lilly; Richard	SP-2484, SUB 1	(07/16/2013)
Lockhart Power Company	SP-1016, SUB 2	(01/02/2013)
	SP-1016, SUB 3	(01/02/2013)

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Orders Issued (Continued)

Company	Docket No.	Date
Loy Farm Solar LLC	SP-2250, SUB 0	(03/08/2013)
Madison County Public Schools	SP-432, SUB 4	(10/02/2013)
Mayfield; John	SP-2576, SUB 1	(10/11/2013)
Miles; Andrew	SP-2053, SUB 1	(01/18/2013)
Mill Solar 1, LLC	SP-2142, SUB 0	(10/17/2013)
Morris; Dexter L. & Patricia S. Tennis	SP-278, SUB 1	(03/08/2013)
Mount Olive Farm 2, LLC	SP-2180, SUB 1	(03/19/2013)
Nashville Farms, LLC	SP-1726, SUB 2	(09/13/2013)
Neisler Street Solar I, LLC	SP-2786, SUB 0	(10/11/2013)
North Carolina Renewable Properties, LLC	SP-1134, SUB 1	(07/16/2013)
Oliver Solar LLC	SP-2109, SUB 0	(03/08/2013)
Onslow Energy, LLC	SP-2364, SUB 0	(04/11/2013)
Papula; Lawrence M.	SP-2635, SUB 0	(10/11/2013)
Patel; Snehalkumar V.	SP-2397, SUB 1	(04/29/2013)
Pine Street Solar, LLC	SP-2322, SUB 0	(04/11/2013)
Pitt Electric, Inc.	SP-2413, SUB 0	(04/29/2013)
Plutusmax, LLC	SP-1522, SUB 3	(06/03/2013)
Pomp; Daniel H.	SP-2008, SUB 1	(03/08/2013)
Radiant Solar at Pumpkin Patch Mtn., LLC	SP-2350, SUB 0	(04/11/2013)
Radiant Solar at Sharp Top, LLC	SP-2351, SUB 0	(04/11/2013)
Ray Family Farms, LLC	SP-1415, SUB 1	(02/25/2013)
Rooney; Michael Patrick	SP-2320, SUB 0	(04/11/2013)
Rufty; Mark	SP-2816, SUB 0	(10/11/2013)
Rushing; Terry	SP-2875, SUB 0	(10/11/2013)
Rutherford County	SP-1801, SUB 1	(03/08/2013)
Sampson Solar, LLC	SP-2298, SUB 0	(04/09/2013)
Sander; James M.	SP-2234, SUB 0	(01/02/2013)
Shankoff; Gregory P.	SP-2227, SUB 1	(03/08/2013)
Snow Hill Solar LLC	SP-2317, SUB 0	(02/08/2013)
Snow Hill Solar 2 LLC	SP-2361, SUB 0	(02/08/2013)
South Atlantic Services, Inc.	SP-2820, SUB 0	(10/11/2013)
	SP-2820, SUB 1	(10/11/2013)
Southeastern Freight Lines, Inc.	SP-2185, SUB 0	(01/02/2013)
Sustainable Solar, LLC	SP-2879, SUB 0	(10/02/2013)
TelExpress, Inc.	SP-2239, SUB 0	(02/18/2013)
	SP-2239, SUB 1	(08/09/2013)
Tier One Solar, LLC	SP-2401, SUB 1	(04/11/2013)
Town of Cary	SP-2094, SUB 1	(04/29/2013)
Town of Mars Hill	SP-2561, SUB 0	(10/02/2013)
Triangle Realty Investment, LLC	SP-630, SUB 9	(04/26/2013)
	SP-630, SUB 10	(04/26/2013)

ORDER ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY

Orders Issued *(Continued)*

Company	Docket No.	Date
Tyson; Joe	SP-2222, SUB 1	(10/02/2013)
Van Buren; Frank L.	SP-2029, SUB 1	(10/03/2013)
Vandewouw; Dave	SP-930, SUB 5	(04/26/2013)
	SP-930, SUB 6	(06/03/2013)
Verano Properties, LLC	SP-2117, SUB 0	(01/02/2013)
Vickers Farm, LLC	SP-2370, SUB 0	(01/08/2013)
Vondracek; Karl	SP-2430, SUB 0	(04/29/2013)
Wake Forest Chiropractic	SP-1554, SUB 1	(03/12/2013)
Wake Solar, LLC	SP-2164, SUB 0	(09/13/2013)
Waller; Steven	SP-1275, SUB 4	(06/03/2013)
Washington White Post Solar, LLC	SP-2114, SUB 1	(03/08/2013)
Wayne Solar I, LLC	SP-2273, SUB 1	(10/02/2013)
Wayne Solar II, LLC	SP-2281, SUB 1	(10/02/2013)
Wayne Solar III, LLC	SP-2359, SUB 1	(10/02/2013)
Webster; Jason & Letitia	SP-2433, SUB 1	(03/08/2013)
West Wayne Solar LLC	SP-2354, SUB 0	(02/08/2013)
Windsor Solar, LLC	SP-2500, SUB 0	(06/05/2013)
York Road Solar I, LLC	SP-2817, SUB 0	(10/11/2013)
Young; Russell D. & Leslie J.	SP-1785, SUB 1	(09/11/2013)
349 Cayuga, LLC	SP-2871, SUB 0	(10/11/2013)

Ampersand Mt. Ida Hydro, LLC -- SP-2795, SUB 0 (12/27/2013); Errata Order (12/31/2013)

Ashley Solar Farm, LLC – SP-2736, SUB 0; Order Amending Certificate of Public Convenience and Necessity and Registration Statement (11/19/2013)

Barnabas Investment Group, LLC -- SP 1325, Sub 0; SP-2585, SUB 0; Order Transferring Certificate of Public Convenience and Necessity and Registration of New Renewable Energy Facility and Closing Docket (03/21/2013)

Carolina Solar Energy II, LLC **–** SP-2363, SUB 2; SP-2830, SUB 0; Order Transferring and Amending Certificate of Public Convenience and Necessity and Registration of New Renewable Energy Facility (07/17/2013)

Clean Energy, LLC **–** SP-2422, SUB 1; Order Amending Registration of New Renewable Energy Facility (12/20/2013)

Clifton; Paul K. II -- SP-810, SUB 2; Order Accepting Amended Registration of New Renewable Energy Facility (01/18/2013)

Element Markets LFG, LLC **–** SP-1838, SUB 0; Order Amending Certificate of Public Convenience and Necessity and Registration Statement (08/28/2013)

ESA Renewables III, LLC **–** SP-1117, SUB 0; Order Amending Registration of New Renewable Energy Facility (10/09/13)

SMALL POWER PRODUCERS -- Filings Due Per Order or Rule *(Continued)*

Farm 9081, LLC **–** SP-1815, SUB 0; SP-1413, SUB 2; Order Cancelling Registration, Closing Docket, and Accepting Registration of New Renewable Energy Facility (04/17/2013)

Knight; Heath **–** SP-1441, SUB 1; Order Allowing Withdrawal of Registration (09/06/2013)

New World Renewable Energy Leasing, Inc. **–** SP-1039, SUB 2; Order Amending Registration of New Renewable Energy Facility (10/09/2013)

Plymouth Solar, LLC -- SP 1568, SUB 0; Order Amending Certificate and Registration of New Renewable Energy Facility (10/01/2013); Errata Order (10/02/2013)

Rockingham County -- SP 1249, SUB 1; Order Amending Registration of New Renewable Energy Facility (10/09/2013)

Rocky Knoll Farm, LP **–** SP-813, SUB 0; Order Revoking Registration of Renewable Energy Facility (07/16/2013)

Storms; William R. -- SP-1360, SUB 0; SP-2147, SUB 0; Order Transferring Registration as a New Renewable Energy Facility (10/09/2013)

Wake Technical Community College Foundation, Inc. **–** SP-1595, SUB 0; SP-1900, SUB 0; Order Accepting Registration of New Renewable Energy Facility and Closing Docket (01/02/2013)

Weyerhaeuser NR Company **–** SP-2285, SUB 0; Order Accepting Registration as a Renewable Energy Facility (06/18/2013)

SMALL POWER PRODUCERS – Registration Statements

Ayden HTP Partners LLC **–** SP-1005, SUB 0; Order Withdrawing Registration Statement and Closing Docket (01/02/2013)

Clean Energy, LLC **–** SP-1927, SUB 0; SP-2422, SUB 1; Order Assigning New Docket Number and Closing Original Docket (01/11/2013)

Hardcastle; Eric **–** SP-2508, SUB 0; Order Withdrawing Withdrawal of Application and Closing Docket (07/16/2013)

McElfresh, Jr;. John K. **–** SP-1831, SUB 0; Order Clarifying Filing and Closing Docket (01/02/2013)

New Century Solar, LLC **–** SP-2090, SUB 0; Order Withdrawing Registration Statement and Closing Docket (01/02/2013)

REI 2, LLC **–** SP-2014, SUB 0; SP-2422, SUB 0; Order Assigning New Docket Number and Closing Original Docket (01/11/2013)

SMALL POWER PRODUCERS – Sale/Transfer

DEGS NC Solar, LLC **–** SP-2357,

SUB 1; SUB 2; SP-2970, SUB 0; Order Transfering and Amending Certificate of Public Convenience and Necessity (09/26/2013)

SUB 0; SP-3177, SUB 0; Order Transfering and Amending Certificate of Public Convenience and Necessity (12/11/2013)

SMALL POWER PRODUCERS – Sale/Transfer *(Continued)*

***Geenex, LLC* –** SP-2465, SUB 0 & SUB 2; SP-2887, SUB 0; Order Transferring Certificate of Public Convenience and Necessity and Accepting Registration Statement (10/24/2013)

Haw River Hydro Co. -- SP-101, SUB 2; SP-4, SUB 1; Order Transferring Certificate of Public Convenience and Necessity (12/03/2013)

***Laurel Hill Farm, LLC* –** SP-2713, SUB 0; SP-2197, SUB 1; Order Transferring Certificate of Public Convenience and Necessity and Accepting Registration Statement (12/20/2013)

***Oakboro Farm, LLC* –** SP-2197, SUB 0; SP-3216, SUB 0; Order Transferring Certificate of Public Convenience and Necessity and Accepting Registration Statement (12/20/2013)

***SoINCPower1, LLC* –** SP-2910, SUB 1; SP-3220, SUB 0; Order Transferring Certificate of Public Convenience and Necessity (12/11/2013)

***SunEnergy 1, LLC* –** SP-751,

- SUB 20; SUB 24; SP-2999, SUB 0; Order Transfering Certificate of Public Convenience and Necessity (11/27/2013)
- SUB 14; SP-3190, SUB 0; Order Transfering Certificate of Public Convenience and Necessity (12/11/2013)

SunPower Corp. -- SP-2083, SUB 1; SP-1642, SUB 2; Order Transferring and Amending Certificate of Public Convenience and Necessity (08/21/2013)

SPECIAL CERTIFICATE/PSP

SPECIAL CERTIFICATE/PSP – Certificate

ORDER ISSUING CERTIFICATE

Orders Issued

Company	Docket No.	Date
Atlantic Telecom, LLC	SC-1816, SUB 0	(06/21/2013)
Combined Public Communications, Inc.	SC-1741, SUB 2	(12/02/2013)
Marcie Robson	SC-1817, SUB 0	(07/26/2013)

SPECIAL CERTIFICATE/PSP -- Cancellation of Certificate

ORDER CANCELING CERTIFICATE

Orders Issued

Company	Docket No.	Date
Abdo Saleh, Inc.	SC-1809, SUB 1	(03/06/2013)
Barnardsville Telephone Company	SC-1394, SUB 1	(12/11/2013)
Charlotte Management Associates	SC-551, SUB 1	(10/25/2013)
Cinemark USA, Inc.	SC-1112, SUB 2	(03/05/2013)
Lance, Inc.	SC-489, SUB 2	(02/25/2013)
Saluda Mountain Telephone Company	SC-1395, SUB 1	(12/11/2013)

ORDERS AND DECISIONS LISTED

TELECOMMUNICATIONS

TELECOMMUNICATIONS -- Certificate

LOCAL CERTIFICATE

Orders Issued

Company	Docket No.	Date
Access/On Interexchange Services, Inc.	P-418, SUB 3	(09/30/2013)
Carrboro Telephone, Inc.	P-1556, SUB 1	(10/03/2013)
Conterra Ultra Broadband, LLC	P-1359, SUB 1	(07/10/2013)
Equinox Global Telecommunications, Inc.	P-1558, SUB 0	(09/05/2013)
First Communications, LLC	P-1412, SUB 1	(08/28/2013)
O1 Communications East, LLC	P-1549, SUB 0	(02/26/2013)
Rural Consumer Services Corporation	P-1557, SUB 0	(08/02/2013)
Sage Telecom Communications, LLC	P-1555, SUB 1	(05/20/2013)
Smithville Telecom, LLC	P-1550, SUB 0	(01/30/2013)
TNCI Operating Company, LLC	P-1554, SUB 0	(05/21/2013)
365 Wireless, LLC	P-1552, SUB 0	(04/25/2013)

LONG DISTANCE CERTIFICATE

Orders Issued

Company	Docket No.	Date
Carrboro Telephone, Inc.	P-1556, SUB 0	(10/07/2013)
LDC Group, LLC, d/b/a Dash Tel, LLC	P-1553, SUB 0	(04/30/2013)
Legent Comm LLC	P-1561, SUB 0	(10/07/2013)
Onvoy, Inc.	P-1562, SUB 0	(10/07/2013)
O1 Communications East, LLC	P-1549, SUB 1	(02/18/2013)
Peak Tower, LLC	P-1560, SUB 0	(09/11/2013)
PT Attachment Solutions, LLC	P-1559, SUB 0	(09/11/2013)
Rural Consumer Services Corporation	P-1557, SUB 1	(07/22/2013)
Sage Telecom Communications, LLC	P-1555, SUB 0	(05/06/2013)
Smithville Telecom, LLC	P-1550, SUB 1	(01/10/2013)
Time Warner Cable Business, LLC	P-1551, SUB 0	(02/18/2013)
TNCI Operating Company, LLC	P-1554, SUB 1	(04/30/2013)
Vodafone Global Enterprise, Inc.	P-1563, SUB 0	(12/06/2013)
Zone Telecom, LLC	P-1033, SUB 2	(01/04/2013)

Crosstel Tandem, Inc. **–** P-1543, SUB 1; Errata Order (03/08/2013)

ORDERS AND DECISIONS LISTED

<u>TELECOMMUNICATIONS -- Cancellation of Certificate</u>

ORDER CANCELING CERTIFICATE
<u>Orders Issued</u>

Company	Docket No.	Date
Absolute Home Phones, Inc.	P-1481, SUB 3	(03/14/2013)
Affordable Phone Services, Inc.	P-1272, SUB 4	(03/14/2013)
Applewood Communications Corp.	P-1436, SUB 1	(02/15/2013)
Digizip.Com, Inc.	P-1178, SUB 1	(05/06/2013)
Ernest Communications, Inc.	P-1054, SUB 1	(11/26/2013)
Get Connected, LLC	P-1449, SUB 1	(11/25/2013)
Globalcom, Inc.	P-998, SUB 1	(08/26/2013)
Lambeau Telecom Company, Inc.	P-1473, SUB 1	(02/15/2013)
Quad Comm, LLC	P-1534, SUB 1	(12/19/2013)
Safari Communications, Inc.	P-1505, SUB 2	(03/14/2013)
	P-1505, SUB 3	(10/07/2013)
Saturn Telecommunications Services, Inc.	P-1336, SUB 1	(02/15/2013)

AT&T Communications of the Southern States, LLC – P-140, SUB 94; Order Canceling Certificates (04/30/2013)

BellSouth Long Distance, Inc. – P-654, SUB 5; Order Cancelling CLP Certificate and Closing Docket (08/22/2013)

Covista, Inc. – P-417, SUB 4; Order Canceling Certificates (08/26/2013)

Crosstel Tandem, Inc. – P-1543, SUB 1; Errata Order (03/08/2013)

Digital Express, Inc. – P-1541, SUB 0; Order Dismissing Application and Closing Docket (02/15/2013)

Lightyear Network Solutions, Inc. – P-1305, SUB 1; Order Canceling Certificates (11/25/2013)

Sage Telecom, Inc. – P-1440, SUB 2; Order Canceling Certificates (10/22/2013)

TCG of the Carolinas, Inc. – P-646, SUB 15; Order Canceling Certificates (04/30/2013)

Trans National Communications International, Inc. -- P-566, SUB 4; Order Cancelling Certificates and Closing Dockets (12/09/2013)

<u>TELECOMMUNICATIONS -- Complaint</u>

BellSouth Telecommunications, LLC – P-55, SUB 1876; Order Dismissing Complaint and Counterclaim and Closing Docket *(Budget Prepay, Inc.)* (02/07/2013)

dPi Teleconnect, LLC – P-836, SUB 5; P-908, SUB 2; P-1272, SUB 1; Order Dismissing Complaints and Counterclaims and Closing Dockets *(BellSouth Telecommunications, Inc., d/b/a AT&T Southeast, d/b/a AT&T North Carolina)* (01/14/2013)

Frontier Communications of the Carolinas, Inc. – P-1488, SUB 30; Order Dismissing Complaint and Closing Docket *(Ruth Shepherd Poole)* (11/20/2013)

LifeConnex Telecom, LLC, f/k/a Swiftel – P-1439, SUB 2; Order Allowing Counsel to Withdraw and Closing Docket *(BellSouth Telecommunications, Inc.)* (01/18/2013)

ORDERS AND DECISIONS LISTED

TELECOMMUNICATIONS -- Contracts/Agreements

ORDER APPROVING AGREEMENT(s) ***or***
ORDER APPROVING AMENDMENT(s)
Orders Issued

Barnardsville Telephone Company -- P-75, SUB 58 *(United States Cellular Corporation)* (02/13/2013)

BellSouth Telecommunications, LLC **–** P-55,
SUB 1371 *(Sprint Communications Company, L.P.)* (03/12/2013)
SUB 1544 *(United States Cellular Corporation)* (02/13/2013)
SUB 1595 *(USA Mobility Wireless, Inc.)* (01/15/2013); (02/13/2013)
SUB 1631 *(AT&T Corp.)* (07/16/2013)
SUB 1653 *(US LEC Communications LLC)* (01/15/2013); (03/12/2013)
SUB 1675 *(American Messaging Services, LLC)* (06/04/2013)
SUB 1691 *(ALEC, LLC)* (04/09/2013); (05/15/2013)
SUB 1710 *(Nextel South Corporation)* (03/12/2013)
SUB 1755 *(BalsamWest FiberNet, LLC)* (12/18/2013)
SUB 1759 *(Cricket Communications, Inc.)* (06/04/2013); (10/31/2013)
SUB 1882 *(North Carolina RSA 3 Cellular Telephone Co.)* (02/13/2013); (02/13/2013)
SUB 1883 *(365 Wireless, LLC)* (03/12/2013); (03/12/2013)
SUB 1885 *(SCANA Communications, Inc.)* (04/09/2013)
SUB 1886 *(Broadvox-CLEC, LLC)* (05/15/2013)
SUB 1888 *(O1 Communications East, LLC)* (09/17/2013)
SUB 1889 *(CeBridge Telecom NC, LLC)* (09/17/2013)
SUB 1890 *(Celito CLEC, LLC)* (11/27/2013)
SUB 1893 *(Atlantic Telecom Multimedia Consolidated, LLC)* (12/18/2013)

Carolina Telephone and Telegraph Co./Central Telephone Co. -- P-7,
SUB 974; P-10, SUB 616 *(Cellco Partnership, d/b/a Verizon Wireless)* (09/17/2013)
SUB 1018; P-10, SUB 654 *(United States Cellular Corporation)* (04/09/2013)
SUB 1059; P-10, SUB 693 *(tw telecom of north carolina, f/k/a Time Warner Telecom of North Carolina, L.P.)* (05/15/2013)
SUB 1089; P-10, SUB 723 *(Cricket Communications, Inc.)* (06/04/2013)
SUB 1092; P-10, SUB 725 *(Alltel Communications, LLC, d/b/a Verizon Wireless)* (09/17/2013)
SUB 1197; P-10, SUB 817 *(MCImetro Access Transmission Services LLC, /d/b/a Verizon)* (04/09/2013)
SUB 1222; P-10, SUB 839 *(AT&T Communications of the Southern States, LLC)* (02/13/2013)
SUB 1254; P-10, SUB 869 *(Broadvox-CLEC, LLC)* (01/15/2013); (09/17/2013)
SUB 1255; P-10, SUB 870 *(DukeNet Communications, LLC)* (02/13/2013)
SUB 1256; P-10, SUB 871 *(Time Warner Cable Information Services (North Carolina, LLC)* (04/09/2013)
SUB 1258; P-10, SUB 874 *(365 Wireless, LLC)* (05/15/2013)

ORDER APPROVING AGREEMENT(s) ***or***
ORDER APPROVING AMENDMENT(s)
Orders Issued (Continued)

Carolina Telephone and Telegraph Company LLC, d/b/a CenturyLink -- P-7, SUB 1261 *(MegaPath Corporation)* (11/27/2013)
Central Telephone Company, d/b/a CenturyLink -- P-10, SUB 876 *(MegaPath Corporation)* (11/27/2013)
Citizens Telephone Company – P-12,
SUB 100 *(New Cingular Wireless PCS, LLC)* (06/04/2013)
SUB 105 *(Verizon Wireless)* (06/04/2013)
SUB 106 *(United States Cellular Corporation)* (12/18/2013)
Ellerbe Telephone Company – P-21, SUB 71 *(Allied Wireless Communications Corporation)* (02/13/2013)
Frontier Communications of the Carolinas, Inc. -- P-1488,
SUB 28 *(North Carolina RSA 1 Partnership)* (04/09/2013)
SUB 29 *(USCOC of Greater North Carolina, LLC)* (04/09/2013)
SUB 31 *(Cricket Communications, Inc.)* (05/15/2013)
SUB 32 *(Verizon Wireless)* (05/15/2013)
SUB 33 *(Qwest Communications Company, LLC, d/b/a CenturyLink QCC)* (05/15/2013)
MCImetro Access Transmission Services, LLC – P-474, SUB 14 *(BellSouth Telecommunications, LLC)* (01/15/2013)
Mebtel, Inc. – P-35,
SUB 105 *(United States Cellular Corporation)* (05/15/2013)
SUB 107 *(New Cingular Wireless PCS, LLC, d/b/a AT&T Mobility)* (07/16/2013)
SUB 121 *(Cellco Partnership, d/b/a Verizon Wireless)* (12/18/2013)
North State Telephone Company – P-42,
SUB 129 *(Sprint Spectrum L.P.)* (06/04/2013)
SUB 130 *(Nextel South Corp.)* (06/04/2013)
SUB 132 *(Cricket Communications, Inc.)* (07/16/2013)
SUB 155 *(United States Cellular Corporation)* (02/13/2013)
Saluda Mountain Telephone Company – P-76, SUB 48 *(United States Cellular Corporation)* (02/13/2013)
Service Telephone Company – P-60, SUB 69 *(United States Cellular Corporation)* (02/13/2013)
tw telecom of north carolina l.p. -- P-472, SUB 25 *(Pineville Telephone Company)* (12/18/2013)
Verizon South, Inc. – P-19,
SUB 312 *(Nextel South Corp.)* (10/31/2013)
SUB 322 *(Sprintcom, Inc., d/b/a Sprint PCS)* (10/31 /2013)
SUB 471 *(North Carolina RSA 1 Partnership)* (08/21/2013)
Windstream Concord Telephone, Inc. P-16,
SUB 252; P-118, SUB 186 *(Frontier Communications of America, Inc.)* (03/12/2013)
SUB 253 *(Metropolitan Telecommunications of North Carolina, Inc., d/b/a MetTel)* (08/21/2013)

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ORDER APPROVING AGREEMENT(s) ***or***
ORDER APPROVING AMENDMENT(s)
Orders Issued *(Continued)*

Windstream Lexcom Communications, Inc. – P-31, SUB 155 *(Metropolitan Telecommunications of North Carolina, Inc., d/b/a MetTel)* (08/21/2013)
Windstream North Carolina, LLC – P-118, SUB 187 *(Metropolitan Telecommunications of North Carolina, Inc., d/b/a MetTel)* (08/21/2013)

TELECOMMUNICATIONS -- Discontinuance
Fast Phones, Inc. – P-1468, SUB 1; Order Granting Petition to Discontinue Service (02/01/2013); Errata Order (02/01/2013)
Linkup Telecomm, Inc. – P-1486, SUB 1; Order Granting Petition to Discontinue Service (01/30/2013)

TELECOMMUNICATIONS -- Miscellaneous
BellSouth Telecommunications, LLC, d/b/a AT&T North Carolina -- P-55,
SUB 1881; Order Granting Numbering Resources (01/02/2013)
SUB 1884; Order Granting Numbering Resources (02/12/2013)
SUB 1887; Order Granting Numbering Resources (06/17/2013)
SUB 1891; Order Granting Numbering Resources (10/14/2013)
SUB 1892; Order Granting Numbering Resources (10/11/2013)
Carolina Telephone and Telegraph Co., d/b/a CenturyLink -- P-7,
SUB 1257; P-10, SUB 872; Order Authorizing Disconnection (04/23/2013)
SUB 1259; Order Granting Numbering Resources (04/09/2013)
Deltacom, LLC, d/b/a Earthlink Business – P-500, SUB 25; Order Granting Numbering Resources (12/20/2013)
MCImetro Access Transmission Services – P-474,
SUB 20; Order Granting Numbering Resources (04/08/2013)
SUB 21; Order Granting Numbering Resources (03/04/2013)
US LEC of North Carolina LLC – P-561, SUB 29; Order Granting Numbering Resources (03/26/2013)
Windstream Communications, Inc. – P-1394, SUB 3; P-561, SUB 29; Order Rescinding Order in Docket No. P 561, Sub 29 and Granting Numbering Resources to WCI in Docket No. P-1394, Sub 3 (05/28/2013)
Windstream North Carolina, LLC – P-118, SUB 185; Order Granting Numbering Resources (01/02/2013)
Windstream Nuvox, Inc. – P-1341,
SUB 4; Order Granting Numbering Resources (08/08/2013)
SUB 5; Order Granting Numbering Resources (08/19/2013)
SUB 6; Order Granting Numbering Resources (10/11/2013); Errata Order (10/16/2013)

TELECOMMUNICATIONS – Sale/Transfer
TNCI Operating Company, LLC – P-1554, SUB 2; P-566, SUB 4; Order Approving Transfer of Customers and Waiving Commission Rule R20 1 Requirements (07/22/2013)

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TRANSPORTATION

TRANSPORTATION -- Cancellation of Certificate

ORDER CANCELING CERTIFICATE OF EXEMPTION
Orders Issued

Company	Docket No.	Date
On the Road Movers, d/b/a; Jerry Thomas Ellis	T-4464, SUB 3	(05/09/2013)
R.D. Helms Transfer Co.	T-4224, SUB 6	(07/08/2013)
Woodruff Trucking, Inc.	T-4234, SUB 2	(02/07/2013)
3 D's Truck & Moving, d/b/a; Denetrice Faye Pittman	T-4484, SUB 2	(07/08/2013)

Handy Help Moving, LLC **–** T-4219, SUB 3; Order Canceling Show Cause Hearing and Canceling Certificate of Exemption (07/30/2013)

TRANSPORTATION – Common Carrier Certificate

ORDER GRANTING APPLICATION FOR CERTIFICATE OF EXEMPTION
Orders Issued

Company	Docket No.	Date
Alternative Moving & Storage, LLC	T-4502, SUB 0	(06/25/2013)
Athletes Movers, Inc.	T-4507, SUB 0	(03/27/2013)
Beso Del Sol Holdings, LLC, d/b/a Little Guys Movers of Greensboro	T-4506, SUB 0	(02/01/2013)
Bones Taylor Moving, LLC	T-4518, SUB 0	(10/25/2013)
Guardian Transfer & Storage, LLC	T-4504, SUB 0	(05/06/2013)
Hill; Matthew Craig, d/b/a OBX Movers	T-4512, SUB 0	(07/01/2013)
Holloway; Roy D., d/b/a Scooby Moving Co.	T-4508, SUB 0	(04/26/2013)
JB Movers, Inc.	T-4520, SUB 0	(10/25/2013)
Martin Holdings, Inc., d/b/a Martin Movers	T-4516, SUB 0	(07/25/2013)
Moore and Moore Movers	T-4522, SUB 0	(10/01/2013)
Moving Simplified, Inc.	T-4415, SUB 5	(07/03/2013)
Naglee Moving & Storage, Inc.	T-4519, SUB 0	(08/27/2013)
Sawyer Enterprises of Pensacola, Inc., d/b/a Sawyers E Z Move	T-4395, SUB 4	(04/26/2013)

ORDERS AND DECISIONS LISTED

ORDER GRANTING APPLICATION FOR CERTIFICATE OF EXEMPTION
Orders Issued *(Continued)*

Company	Docket No.	Date
Sheppard; James Earl, d/b/a Ken's Pack & Move	T-4498, SUB 0	(04/02/2013)
West Moving and Storage Company, LLC	T-4493, SUB 0	(02/21/2013)
Xtreme Moving & Storage, LLC	T-4513, SUB 0	(08/30/2013)

Hall; Joy Jessica, d/b/a Joyful Movers **–** T-4418, SUB 2; Recommended Order Granting Application for Certificate of Exemption (05/22/2013)

TRANSPORTATION -- Complaint

Kapili; John and Pegge -- T-4135, SUB 3; Order Dismissing Complaint and Closing Docket *(John's Moving & Storage)* (06/20/2013)

Saitta; Molly **–** T-4395, SUB 2; Order Dismissing Complaint and Closing Docket *(Sawyers E.Z. Move)* (01/07/2013)

TRANSPORTATION -- Miscellaneous

Rates-Truck -- T-825, SUB 348; Order Approving Fuel Surcharge (03/05/2013); (04/02/2013); (04/30/2013); (06/25/2013); (08/06/2013); (11/06/2013)

TRANSPORTATION -- Name Change

ACE Movers **–** T-4324, SUB 4; Order Approving Name Change (07/11/2013)

Berger Transfer & Storage, Inc. **–** T-4169, SUB 3; Order Approving Name Change (03/07/2013)

Best Movers US Inc. **–** T-4485, SUB 2; Order Approving Name Change (07/08/2013)

Cameron & Cameron, Assembly, Moving and Storage, Inc. **–** T-4237, SUB 3; Order Approving Name Change (07/23/2013)

Coastal Carrier Moving & Storage Co. **–** T-4174, SUB 5; Order Approving Name Change (08/02/2013)

Local Movers, LLC **–** T-4492, SUB 1; Order Approving Name Change (07/23/2013)

TRANSPORTATION -- Sale/Transfer

J Five Investments, Inc., d/b/a Steele & Vaughn Moving & Storage -- T-4509, SUB 0; T-4228, SUB 4; Order Approving Transfer and Name Change (06/05/2013)

TRANSPORTATION – Show Cause

Crofutt & Smith Storage Warehouse of North Carolina, Inc. **–** T-3803, SUB 6; Order Canceling Show Cause Hearing and Canceling Certificate of Exemption (08/07/2013)

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TRANSPORTATION -- Suspension

A & A Moving; Pitt Movers, Inc., d/b/a – T-2939, SUB 5; Order Granting Authorized Suspension (01/08/2013)

Blue Ridge Movers, Inc. – T-4359, SUB 2; Order Granting Authorized Suspension (05/10/2013)

CEH Moving, Inc. – T-4467, SUB 2; Order Granting Authorized Suspension (04/26/2013)

DeHaven's Transfer & Storage of Raleigh, Inc. – T-2490, SUB 9; Order Granting Authorized Suspension (02/07/2013)

DeHaven's Transfer & Storage of Wilson, Inc. – T-3255, SUB 8; Order Granting Authorized Suspension (02/19/2013)

Fleming-Shaw Transfer and Storage, Inc. – T-60, SUB 4; Order Granting Authorized Suspension (02/07/2013)

Holloway Moving & Storage, Inc. – T-4122, SUB 4; Order Canceling Show Cause Hearing and Granting Authorized Suspension (04/26/2013); Order Rescinding Order Granting Authorized Suspension (07/11/2013)

Parks Transfer, d/b/a; Walter R. Parks – T-4313, SUB 2; Order Granting Authorized Suspension (03/07/2013)

Regency Moving & Storage, LLC – T-4447, SUB 2; Order Granting Authorized Suspension (05/10/2013)

Unique Movers, d/b/a; Willard Jones – T-4501, SUB 1; Order Granting Authorized Suspension (05/10/2013)

West Moving and Storage Company, LLC – T-4493, SUB 1; Order Granting Authorized Suspension (08/26/2013)

3 D's Truck & Moving, d/b/a; Denetrice F. Pittman – T-4484, SUB 1; Order Granting Authorized Suspension (05/10/13)

WATER AND SEWER

WATER AND SEWER -- Bonding

Water Quality Services, Inc. – W-1099, SUB 14; Order Approving Surety and Releasing Surety (03/20/2013)

WATER AND SEWER -- Certificate

Aqua North Carolina, Inc. -- W-218,
SUB 341; Order Granting Franchise and Approving Rates (01/29/2013)
SUB 354; Order Granting Franchise and Approving Rates (07/11/2013)
SUB 362; Order Granting Franchise and Approving Rates (07/11/2013)

Bradfield Farms Water Co. – W-1044, SUB 19; Errata Order (01/10/2013)

Dillsboro Water and Sewer, Inc. – W-1303, SUB 0; Recommended Order Approving Stipulation and Refund and Granting Temporary Operating Authority (04/22/2013)

Harkers Island Sewer Company LLC – W-1297, SUB 0; Order Granting Franchise, Approving Rates, and Requiring Customer Notice (07/30/2013)

Old North State Water Company, LLC – W-1300, SUB 0; Recommended Order Granting Franchise, Approving Rates, and Requiring Customer Notice (01/07/2013)

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WATER AND SEWER -- Complaint

Aqua North Carolina, Inc. **–** W-218,

SUB 346; Recommended Order Denying Complaint ***(Elva Ramseur)*** (08/16/2013)

SUB 374; Order Dismissing Complaint and Closing Docket *(Jeff Richter)* (11/06/2013)

WATER AND SEWER – Contiguous Water Extension

Aqua North Carolina, Inc. – W-218,

SUB 347; Order Recognizing Contiguous Extension and Approving Rates *(High Grove Subdivision)* (01/29/2013)

SUB 350; Order Recognizing Contiguous Extension and Approving Rates *(Flowers Crest Subdivision)* (07/11/2013)

SUB 353; Order Recognizing Contiguous Extension and Approving Rates *(Sailors Lair Subdivision)* (07/11/2013)

SUB 355; Order Recognizing Contiguous Extension and Approving Rates *(Trillium Subdivision)* (07/11/2013)

SUB 357; Order Recognizing Contiguous Extension and Approving Rates *(Beaver Farms Subdivision)* (11/13/2013)

SUB 358; Order Recognizing Contiguous Extension and Approving Rates *(Chatham Subdivision)* (10/01/2013)

SUB 359; Order Recognizing Contiguous Extension and Approving Rates *(Flowers POD 6A Subdivision)* (10/01/2013)

SUB 365; Order Recognizing Contiguous Extension and Approving Rates *(Hasentree East Subdivision)* (11/12/2013)

KDHWWTP, LLC -- W 1160,

SUB 17; Order Recognizing Contiguous Extension *(WRB Rentals)* (02/11/2013)

SUB 18; Order Recognizing Contiguous Extension *(Lane Investment Properties N.C.)* (02/11/2013)

SUB 21; Order Recognizing Contiguous Extension *(Seven C's Condos)* (12/17/2013)

WATER AND SEWER -- Discontinuance

Cardinal Estates Water System **–** W-701, SUB 2; Order Canceling Franchise (02/19/2013)

WATER AND SEWER – Rate Increase

Carolina Trace Utilities, Inc. – W-1013, SUB 9; Order Terminating Annual Reporting Requirement and Closing Docket (11/22/2013)

GGCC Utility, Inc. – W-755, SUB 7; Order Granting Rate Increase and Requiring Customer Notice *(Granfather Golf and Country Club Development)* (10/14/2013)

Pluris, LLC **–** W-1282, SUB 8; Order Amending Tariff to Include an NSF Charge and Denying Request to Amend Tariff to Recover Rates for Periods When Customer Was Disconnected *(Onslow County)* (06/24/2013)

Ridgecrest Water Utility – W-71, SUB 10; Order Granting Rate Increase and Requiring Customer Notice *(Ridgecrest Area)* (10/14/2013)

WATER AND SEWER – Rate Increase *(Continued)*

Riverbend Estates Water Systems, Inc. – W-390, SUB 11; Order Granting Franchise, Granting Partial Rate Increase, and Requiring Customer Notice *(Riverbend Estates Subdiv.)* (02/26/2013)

Sandler Utilities at Mill Run, LLC – W-1130, SUB 7; Order Granting Rate Increase and Requiring Customer Notice *(Eagle Creek Subdivision)* (04/02/2013)

WATER AND SEWER -- Sale/Transfer

A&D Water Service, Inc. – W-1049, SUB 16; W-1081, SUB 2; Recommended Order Approving Transfer, Granting Franchise, Approving Rate, and Requiring Customer Notice (07/23/2013)

Aqua North Carolina, Inc. – W-218,

SUB 331; W-943, SUB 2; Recommended Order Approving Transfer, Granting Franchise, Approving Rates, and Requiring Customer Notice (04/08/2013)

SUB 348; W-486, SUB 5; Recommended Order Approving Transfer, Granting Franchise, Approving Rates, and Requiring Customer Notice (04/23/2013)

SUB 349; W-848, SUB 17; Recommended Order Approving Transfer, Granting Franchise, Approving Rates and Requiring Customer Notice (04/22/2013)

Carolina Water Service, Inc. of North Carolina – W-354, SUB 335; W-766, SUB 4; Order
Approving Transfer and Requiring Customer Notice (10/28/2013)

WATER AND SEWER -- Tariff Revision for Pass-Through

ORDER APPROVING TARIFF REVISION

Orders Issued

Company	Docket No.	Date
Aqua North Carolina, Inc.		
(Crestwood, Lancer Acres & Beard Acres Subdivision)	W-218, SUB 352	(03/04/2013)
(Hawthorne at the Green Apts.)	W-218, SUB 356	(05/03/2013)
(Town of Linden in Woodland Run Subdiv.)	W-218, SUB 364	(07/29/2013)
Asheville Property Mgmt., Inc.		
(Popular Terrace Mobile Home Park)	W-1145, SUB 17	(10/28/2013)
Chatham Utilities, Inc.		
(Chatham Estates MH Community)	W-1240, SUB 9	(07/29/2013)
JACTAW Properties, LLC		
(Poplar Acres Mobile Home Park)	W-1209, SUB 7	(10/28/2013)
MECO Utilities, Inc.		
(Mobile Estates Mobile Home Park)	W-1166, SUB 11	(07/29/2013)

WATER AND SEWER -- Tariff Revision for Pass-Through *(Continued)*

Joyceton Water Works, Inc. -- W-4, SUB 16; Order Approving Tariff Revision and Requiring Customer Notice *(Caldwell County)* (07/01/2013)

Old North State Water Company, LLC – W-1300, SUB 3; Order Approving Tariff Revision and Establishing Notification Procedure *(Majestic Oaks Subdivision)* (10/28/2013)

Watercrest Estates – W-1021, SUB 9; Order Approving Tariff Revision and Requiring Customer Notice *(Watercrest Estates MHP)* (07/29/2013)

Whispering Pines Village, d/b/a; John D. Hook – W-1042, SUB 5; Order Approving Tariff Revision and Requiring Customer Notice *(Whispering Pines Village MHP)* (03/19/2013)

RESALE OF WATER AND SEWER

RESALE OF WATER AND SEWER -- Cancellation of Certificate

ORDER CANCELING CERTIFICATE OF AUTHORITY

Orders Issued

Company	Docket No.	Date
Alliance PP2 FX2 Limited Partnership		
(Windsor Harbor Apartments)	WR-786, SUB 9	(11/25/2013)
Arbor Trace Apartments, LLC		
(Arbor Trace Apartments)	WR-222, SUB 6	(12/16/2013)
Arboretum at Weston Holdings, LLC		
(The Arboretum at Weston Apts.)	WR-809, SUB 1	(09/25/2013)
Brentmoor Investments, LLC		
(Brentmoor Apartments)	WR-904, SUB 3	(05/14/2013)
Brier Creek Luxury Apts., LTD. P.		
(The Jamison at Brier Creek Apartments)	WR-1279, SUB 2	(10/08/2013)
Brotherhood Properties Royal Oaks, LLC		
(Otter Creek Mobile Home Park)	WR-1002, SUB 2	(03/20/2013)
(Azalea Mobile Home Park)	WR-1002, SUB 3	(03/20/2013)
Campus-Raleigh, LLC		
(Campus Crossings at Raleigh Apts.)	WR-745, SUB 5	(06/17/2013)
CH Realty III/Durham South Place, LLC		
(Alexan at South Square Apartments)	WR-528, SUB 9	(01/10/2013)
CND Sommerset Place, LLC		
(Sommerset Place Apartments)	WR-746, SUB 4	(05/01/2013)
CRIT-NC Three, LLC		
(Colonial Village at Highland Hills Apts.)	WR-420, SUB 6	(07/02/2013)
Dunhill Trace, LLC		
(Dunhill Trace Apartments)	WR-260, SUB 9	(04/04/2013)
Estates at Meridian, LLC		
(1520 Magnolia Apartments)	WR-434, SUB 2	(08/05/2013)

ORDER CANCELING CERTIFICATE OF AUTHORITY

Orders Issued (Continued)

Company	Docket No.	Date
Fairfield Autumn Woods, LLC		
(Autumn Woods Apartments)	WR-620, SUB 6	(02/26/2013)
Forest Ridge Apartments, LLC		
(Forest Ridge Apartments)	WR-357, SUB 6	(08/05/2013)
Garrett Farms Apartments L.P.		
(Alexan Garrett Farms Apartments)	WR-1023, SUB 4	(08/06/2013)
Gateway Communities, LLC/Park Regency, LLC		
(Arwen Vista Apartments)	WR-948, SUB 3	(06/24/2013)
GMC Charlotte, LLC		
(The Highlands Apartments)	WR-391, SUB 8	(04/23/2013)
Hudson Landings Limited		
(The Landings I Apartments)	WR-996, SUB 1	(02/12/2013)
Lenox at Patterson Place Apts., LLC		
(Lenox at Patterson Place Apartments)	WR-1012, SUB 1	(02/25/2013)
Magnolia Station Apartments, LLC		
(Magnolia Station Apartments)	WR-661, SUB 4	(05/01/2013)
NNN Landing Apartments, LLC, et al.		
(The Landings Apartments)	WR-545, SUB 5	(03/12/2013)
Northlake Investors 288, LLC		
(Ashton Reserve at Northlake Apts.)	WR-1208, SUB 2	(12/02/2013)
Northwoods Mews Associates		
(Northwoods Mews Townhomes Apts.)	WR-882, SUB 1	(12/10/2013)
NR St. Mary's Property Owners, LLC		
(St. Mary's Square Apartments)	WR-1444, SUB 2	(12/19/2013)
Parc at University Tower Apartments, LLC		
(Parc at University Tower Apartments)	WR-1067, SUB 1	(03/06/2013)
Piper Charlotte Apts. L. P.		
(Piper Station Apartments)	WR-941, SUB 3	(04/04/2013)
PRG Landmark Associates, LLC		
(The Villages of Lake Boone Trail Apts.)	WR-1229, SUB 2	(02/04/2013)
Racine Drive Associates, LLC		
(Campus Walk Apartments)	WR-626, SUB 3	(03/25/2013)
Shadowood Apartments, LLC		
(Shadowood Apartments)	WR-903, SUB 4	(08/05/2013)
Star Investments of Cary, LLC		
(Century Oaks Apartments, Phase II)	WR-5, SUB 7	(02/05/2013)
Star/Somer Hidden Oaks, LLC		
(Hidden Oaks Apartments)	WR-1021, SUB 2	(06/11/2013)
Star/Somer Woodbridge, LLC		
(Woodbridge Apartments)	WR-1022, SUB 2	(06/11/2013)

ORDERS AND DECISIONS LISTED

ORDER CANCELING CERTIFICATE OF AUTHORITY

Orders Issued (Continued)

Company	Docket No.	Date
TMP Lodge at Crossroads, LLC		
(The Lodge at Crossroads Apartments)	WR-799, SUB 3	(05/30/2013)
TMP Perry Point, LLC		
(Perry Point Apartments)	WR-1145, SUB 2	(10/08/2013)
VIII New Haven Apartments, LLC		
(New Haven Apts. & Townhouses)	WR-1185, SUB 1	(10/23/2013)
Westmont Commons Apartments, LLC		
(Westmont Commons Apartments)	WR-459, SUB 7	(05/22/2013)
Westmore Apartments, LLC		
(Westmore Apartments)	WR-1109, SUB 2	(05/30/2013)
1225 South Church Apartments, LLC		
(1225 South Church Street Apts.)	WR-1026, SUB 1	(01/10/2013)
1801 Interface Lane Apartments Investors, LLC		
(Autumn Park Apartments)	WR-521, SUB 5	(01/16/2013)
4700 Twisted Oaks, I, LLC		
(Wellington Farms Apartments)	WR-1099, SUB 1	(10/07/2013)

RESALE OF WATER AND SEWER – Certificate

ORDER GRANTING CERTIFICATE OF AUTHORITY AND APPROVING RATES

Orders Issued

Company	Docket No.	Date
Afton Ridge Apartments, LLC		
(Afton Ridge Apartments)	WR-1494, SUB 0	(09/16/2013)
Amberleigh Shores, LLC		
(Amberleigh Shores Apartments)	WR-1522, SUB 0	(11/06/2013)
Amberton at Stonewater, LLC		
(Amberton at Stonewater Apartments)	WR-1455, SUB 0	(07/02/2013)
Arbor Steele Creek, LLC		
(Arbor Steele Creek Apartments)	WR-1499, SUB 0	(12/27/2013)
Arium Research Triangle Park Owner, LLC		
(Arium Research Triangle Park Apts.)	WR-1528, SUB 0	(11/25/2013)
Autumn Park Owner, LLC		
(Autumn Park Charlotte Apartments)	WR-1378, SUB 0	(02/26/2013)
Beckanna Partners, LLC		
(Beckanna on Glenwood Apartments)	WR-1460, SUB 0	(07/09/2013)
Belle Haven Apts., LLC		
(Belle Haven Apartments)	WR-1518, SUB 0	(11/05/2013)

ORDERS AND DECISIONS LISTED

ORDER GRANTING CERTIFICATE OF AUTHORITY AND APPROVING RATES

Orders Issued (Continued)

Company	Docket No.	Date
BH – Marquee Station A1, LLC		
(The Village at Marquee Station Apts.)	WR-1459, SUB 0	(07/09/2013)
BHC-Hawthorne Pinnacle Ridge, LLC		
(Hawthorne Northside Apartments)	WR-1513, SUB 0	(10/30/2013)
Branson-Coleman Properties, LLC		
(Madison Heights Apartments)	WR-1503, SUB 0	(10/08/2013)
Bridford Parkway Apartments, LLC		
(Hawthorne at Bridford Apartments)	WR-1363, SUB 0	(01/10/2013)
BVT Group, LLC		
(Bella Vista Townhomes Apartments)	WR-1396, SUB 0	(03/25/2013)
CCC Sommerset Place, LLC		
(Sommerset Place Apartments)	WR-1446, SUB 0	(06/03/2013)
Cedar Grove MHC, LLC		
(Cedar Grove Mobile Home Park)	WR-1398, SUB 0	(04/01/2013)
Central Pointe Apartments, LLC		
(Central Pointe Apartments)	WR-1479, SUB 0	(08/13/2013)
Colonial Alabama Limited Partnership		
(CR at South End Apartments)	WR-437, SUB 33	(05/22/2013)
Covington Way, LLC		
(Covington Way Apartments)	WR-1512, SUB 0	(10/23/2013)
CP Plum Creek, LLC		
(Elements on Park Apartments)	WR-1397, SUB 0	(03/25/2013)
CPGPI Erwin Mill, LLC		
(Residences at Erwin Mill Apts.)	WR-1436, SUB 0	(05/14/2013)
Crest Brier Creek Apartments, LLC		
(Crest at Brier Creek Apartments)	WR-1429, SUB 0	(04/29/2013)
Crystal Lake, LLC		
(Crystal Lake Apartments)	WR-1456, SUB 0	(07/02/2013)
DPR Parc at University Tower, LLC		
(Parc at University Tower Apts.)	WR-1384, SUB 0	(03/06/2013)
Durham Holdings #1, LLC		
(Amber Oaks Apartments)	WR-1467, SUB 0	(07/18/2013)
East TBR Hamptons Owner, LLC		
(The Hamptons/Research Triangle Apts.)	WR-1370, SUB 0	(01/15/2013)
Edgewood Place, LLC		
(Edgewood Place Apartments)	WR-1511, SUB 0	(10/23/2013)
Elon Crossing, LLC		
(Elon Crossing Apartments)	WR-1535, SUB 0	(12/03/2013)

ORDERS AND DECISIONS LISTED

ORDER GRANTING CERTIFICATE OF AUTHORITY AND APPROVING RATES

Orders Issued (Continued)

Company	Docket No.	Date
Fair Oaks MHP, LLC		
(Fair Oaks Mobile Home Park)	WR-1442, SUB 0	(05/29/2013)
Fountains at New Bern Station, LLC		
(Fountains Southend Apartments)	WR-1410, SUB 0	(04/17/2013)
Fund II Meadows, LLC, et al.		
(The Meadows Apartments, Phase II)	WR-846, SUB 8	(12/31/2013)
Ginkgo BVG, LLC		
(Boundary Village Apartments)	WR-1519, SUB 0	(11/06/2013)
Golden Triangle #1, LLC		
(Crest at Greylyn Apartments)	WR-1400, SUB 0	(04/02/2013)
Greentree Real Estate Services, LLC		
(The Highland Apartments)	WR-1416, SUB 0	(04/23/2013)
Grey Eagle MHP, LLC		
(Grey Eagle Estates Mobile HP)	WR-1546, SUB 0 W-1254, SUB 2	(12/19/2013)
Grove Associates Limited Partnership		
(Whitehall Estates Apartments)	WR-1464, SUB 0	(07/17/2013)
Hawthorne-Midway Cadence, LLC		
(Hawthorne at the Peak Apartments)	WR-1485, SUB 0	(08/27/2013)
Hawthorne-Midway Dunhill, LLC		
(Hawthorne at the Trace Apartments)	WR-1430, SUB 0	(05/01/2013)
Headwaters at Autumn Hall, LLC		
(Autumn Hall Apartments)	WR-1362, SUB 0	(01/10/2013)
Heritage at Arlington Apts., LLC; The		
(The Heritage at Arlington Apartments)	WR-1472, SUB 0	(07/26/2013)
Heritage Gardens, LLC		
(Heritage Gardens Apartments)	WR-1533, SUB 0	(11/27/2013)
Hickory Grove NC Partners, LLC		
(Cameron at Hickory Grove Apartments)	WR-1435, SUB 0	(05/14/2013)
Highlands at Olde Raleigh, LLC		
(Highlands at Olde Raleigh Apts.)	WR-1443, SUB 0	(06/03/2013)
Holiday Park, LLC		
(Hillsborough West Village Apts.)	WR-1463, SUB 0	(07/16/2013)
Holly Springs NC Apartments, LP		
(The Villages at Pecan Grove Apts.)	WR-1508, SUB 0	(10/14/2013)
Interurban Windsor, LLC		
(Windsor Harbor Apartments)	WR-1529, SUB 0	(11/25/2013)
JLB Elizabeth, LLC		
(Venue Apartments)	WR-1549, SUB 0	(12/30/2013)

ORDER GRANTING CERTIFICATE OF AUTHORITY AND APPROVING RATES

Orders Issued *(Continued)*

Company	Docket No.	Date
JLB Southline, LLC		
(Junction 1504 Apartments)	WR-1376, SUB 0	(02/05/2013)
King James Owner, LLC		
(King James Apartments)	WR-1544, SUB 0	(12/19/2013)
Landmark at Chelsea Commons, LP		
(Chelsea Commons Apartments)	WR-1481, SUB 0	(08/21/2013)
Landmark at Eagle Landing, LP		
(Landmark at Eagle Landing Apts.)	WR-1465, SUB 0	(07/18/2013)
Landmark at Watercrest, LP		
(Landmark at Watercrest Apts.)	WR-1466, SUB 0	(07/18/2013)
Langtree HUD Development Company, LLC		
(Langtree Apartments)	WR-1477, SUB 0	(09/16/2013)
Legacy Cornelius, LLC		
(Legacy Cornelius Apartments)	WR-1388, SUB 0	(03/11/2013)
Legends at Hickory, LLC; The		
(The Legends Apartments)	WR-1409, SUB 0	(05/28/2013)
Lofts at Weston SPE, LLC		
(The Lofts at Weston Lakeside Apts.)	WR-1445, SUB 0	(06/03/2013)
Madison Properties, Inc.		
(Pinewood Apartments)	WR-1380, SUB 0	(02/19/2013)
(673 Sand Hill Road Apts.)	WR-1380, SUB 2	(03/11/2013)
Meridian/H.C., LLC		
(Legacy at Meridian Apartments)	WR-1500, SUB 0	(09/24/2013)
Mid-America Apartments, Limited Partnership		
(1225 South Church Apartments)	WR-22, SUB 52	(05/01/2013)
Mission Central Venture One, LLC		
(The Nook Apartments)	WR-1501, SUB 0	(10/02/2013)
Mission Venture Two, LLC		
(29 North Apartments)	WR-1536, SUB 0	(12/10/2013)
Morguard Lodge Apartments, LLC		
(The Lodge at Crossroads Apts.)	WR-1480, SUB 0	(10/14/2013)
Morguard Perry Point Apartments, LLC		
(Perry Point Apartments)	WR-1521, SUB 0	(11/06/2013)
Mosteller Apartments, LLC		
(Estates at Legends Apartments)	WR-1404, SUB 0	(04/08/2013)
New Brentwood, LLC; The		
(Brentwood Apartments)	WR-1453, SUB 0	(07/01/2013)
Northland Windemere, LLC		
(Windemere Apartments)	WR-1369, SUB 0	(01/15/2013)

ORDER GRANTING CERTIFICATE OF AUTHORITY AND APPROVING RATES

Orders Issued (Continued)

Company	Docket No.	Date
Northwestern Mutual Life Insurance Co.; The		
(Chapel Hill North Apartments)	WR-1516, SUB 0 WR-129, SUB 21	(11/01/2013)
(Cosgrove Hill Apartments)	WR-1515, SUB 0 WR-129, SUB 20	(11/01/2013)
Northwoods Apartments, LLC		
(Northwoods Townhomes Apts., Phase I)	WR-1495, SUB 0	(09/16/2013)
NR St. Mary's Property Owners, LLC		
(St. Mary's Square Apartments)	WR-1444, SUB 0	(06/03/2013)
Park Kingston Investors, LLC		
(Park and Kingston Harbor Apts.)	WR-1538, SUB 0	(12/09/2013)
Penwood Associates, LLC		
(Penwood Apartments)	WR-1448, SUB 0	(06/04/2013)
Perimeter Lofts Apartments, LLC		
(Perimeter Lofts Apartments)	WR-1468, SUB 0	(07/18/2013)
Pfalzgraf Communities 6, LLC		
(Shadowood Apartments)	WR-1492, SUB 0	(09/13/2013)
Pfalzgraf Communities 7, LLC		
(Mountcrest Apartments)	WR-1523, SUB 0	(11/13/2013)
PG2, LLC		
(The Gardens at Anthony House Apartments, Phase 2)	WR-1487, SUB 0	(08/28/2013)
Pine Glen Limited Partnership		
(Greens of Pine Glen Apts.)	WR-1399, SUB 0	(04/01/2013)
Piper Station Apartments, LLC		
(Piper Station Apartments)	WR-1432, SUB 0	(05/13/2013)
Plantation at Horse Pen, LLC		
(Plantation at Horsepen Creek Apts.)	WR-1484, SUB 0	(08/27/2013)
Post Parkside at Wade, LP		
(Post Parkside at Wade Apartments)	WR-1440, SUB 0	(05/22/2013)
Rackley; Thomas Newell & Johanna Page		
(Buck's Mobile Home Park)	WR-1437, SUB 0	(05/14/2013)
Ramblewood Venture, LLC		
(Allister North Hills Apartments)	WR-1457, SUB 0	(07/02/2013)
Research Park, LLC		
(Phillips Research Park Apts.)	WR-1470, SUB 0	(07/23/2013)
Ridge at Highland Creek, LLC		
(The Ridge at Highland Creek Apts.)	WR-1392, SUB 0	(03/13/2013)

ORDERS AND DECISIONS LISTED

ORDER GRANTING CERTIFICATE OF AUTHORITY AND APPROVING RATES

Orders Issued (Continued)

Company	Docket No.	Date
SBV-Greensboro-I, LLC		
(Misty Creek Apartments I)	WR-1471, SUB 0 WR-1405, SUB 1	(08/14/2013)
(Misty Creek Apartments II)	WR-1471, SUB 1 WR-1408, SUB 1	(08/14/2013)
(Misty Creek Apartments III)	WR-1471, SUB 2 WR-1406, SUB 1	(08/14/2013)
Selona Partners, LLC		
(Waterstone at Brier Creek Apts.)	WR-1438, SUB 0	(05/21/2013)
Simpson Woodfield Silos, LLC		
(Silos South End Apartments)	WR-1526, SUB 0	(11/20/2013)
South Square Owner, LLC		
(Alden Place at South Square Apts.)	WR-1387, SUB 0	(02/20/2013)
Southbridge Multifamily, LLC		
(Stillwater at Southbridge Apartments)	WR-1390, SUB 0	(03/12/2013)
Southwood Realty Company		
(The Landings Apartments)	WR-910, SUB 10	(02/12/2013)
(Catawba Apartments)	WR-910, SUB 11	(08/28/2013)
(The Landings Apartments)	WR-910, SUB 12	(12/23/2013)
Steele Creek Charlotte Associates, LLC		
(Sterling Steele Creek Apartments)	WR-1449, SUB 0	(06/04/2013)
Sureties Unlimited 2, LLC		
(Pinewood Trace Apartments)	WR-1377, SUB 0	(02/11/2013)
Sweetwater Meadows, LLC		
(Sweetwater Meadows Mobile HP)	WR-1375, SUB 0	(02/05/2013)
Titan Colony, LLC		
(Colony Apartments)	WR-1395, SUB 0	(03/18/2013)
TPADRP, LLC		
(Sterling Town Center Apartments)	WR-1411, SUB 0	(04/17/2013)
TR Brier Creek, LLC		
(The Jamison at Brier Creek Apartments)	WR-1524, SUB 0	(11/13/2013)
Triangle Cloisters of Mt. Holly, Inc.		
(The Cloisters of Mt. Holly Apts.)	WR-1532, SUB 0	(11/26/2013)
Triangle Riverfront, Inc.		
(Riverfront Apartments)	WR-1452, SUB 0	(07/01/2013)
Trinity Commons		
(Trinity Commons at Erwin Apts.)	WR-1517, SUB 0 WR-129, SUB 22	(11/01/2013)
Tritex Real Estate Advisors, Inc.		
(Hanover Landing Apartments)	WR-1273, SUB 1	(03/25/2013)

ORDERS AND DECISIONS LISTED

ORDER GRANTING CERTIFICATE OF AUTHORITY
AND APPROVING RATES
Orders Issued *(Continued)*

Company	Docket No.	Date
TS Westmont, LLC		
(Westmont Commons Apartments)	WR-1462, SUB 0	(07/09/2013)
Turkey Point, LLC		
(Turkey Point Apartments)	WR-1514, SUB 0	(10/30/2013)
Tyler's Ridge Apartments, LLC		
(Tyler's Ridge Apartments)	WR-1507, SUB 0	(10/14/2013)
VTT Carver Pond, LLC		
(Meriwether Place Apartments)	WR-1509, SUB 0	(10/23/2013)
VTT Charlotte, LLC		
(Forest Ridge Apartments)	WR-1506, SUB 0	(10/08/2013)
Wake Broadstone Associates, LLC		
(The Columns at Broadstone Apts.)	WR-1441, SUB 0	(05/29/2013)
Wake Forest Apartments, LLC		
(Estates at Wake Forest Apartments)	WR-1510, SUB 0	(11/26/2013)
Waterlynn Partners, LLC		
(The Venue Apartments)	WR-1530, SUB 0	(11/25/2013)
Wellington United, LLC		
(Wellington Farms Apartments)	WR-1527, SUB 0	(11/20/2013)
West Morgan, LLC		
(927 West Morgan Apartments)	WR-1428, SUB 0	(04/29/2013)
Wilmington Student Housing, LLC		
(Campus Walk I Apartments)	WR-1431, SUB 0	(05/06/2013)
WMCi Charlotte XIV, LLC		
(Bexley Village at Concord Mills II Apts.)	WR-1474, SUB 0	(08/05/2013)
Worthing South LaSalle, LLC		
(The Heights at LaSalle Apartments)	WR-1450, SUB 0	(06/10/2013)
WRT Lake Brandt Property, LLC		
(Lake Brandt Apartments)	WR-1368, SUB 0	(01/15/2013)
Yanagi, LLC		
(Bryan Woods Apartment Homes)	WR-1475, SUB 0	(08/05/2013)
Yopp Properties, LLC		
(West Meadows Apartments)	WR-1401, SUB 0	(04/02/2013)
York Ridge Associates, LP		
(York Ridge Apartments)	WR-1451, SUB 0	(06/17/2013)
2 Hiltin Place Greensboro, LLC		
(Park Place Apartments)	WR-1473, SUB 0	(07/31/2013)
18 Weather Hill Circle Holdings, LLC		
(The Landing Apartments)	WR-1389, SUB 0	(03/12/2013)
330 West Tremont, LLC		
(335 Apartments)	WR-1548, SUB 0	(12/30/2013)

ORDERS AND DECISIONS LISTED

ORDER GRANTING CERTIFICATE OF AUTHORITY AND APPROVING RATES

Orders Issued *(Continued)*

Company	Docket No.	Date
2052, LLC		
(Clairmont at Brier Creek Apartments)	WR-1525, SUB 0	(11/13/2013)
5205 Barbee Chapel Road Apts., Investors I, LLC		
(Springs of Chapel Hill Apartments)	WR-1505, SUB 0	(10/08/2013)

Crystal Lake NC, LLC **–** WR-1456, SUB 0; Reissued Order Granting Certificate of Authority and Approving Rates (07/10/2013)

East TBR Hamptons Owner, LLC **–** WR-1370, SUB 0; Errata Order *(The Hamptons at Research Triangle Apts.)* (02/07/2013)

ORDER GRANTING HWCCWA CERTIFICATE OF AUTHORITY AND APPROVING RATES

Orders Issued

Company	Docket No.	Date
CPGPI Erwin Mill, LLC		
(Erwin Mill Apartments)	WR-1436, SUB 1	(09/11/2013)
CSC Midtown, LLC		
(Midtown Park Apartments)	WR-1482, SUB 0	(08/21/2013)
Fund II Meadows, LLC, et al.		
(The Meadows Apts., Phase I)	WR-846, SUB 7	(12/31/2013)
Hawthorne-Midway Turtle Creek, LLC		
(Hawthorne at Southside Apartments)	WR-1497, SUB 0	(09/23/2013)
Hawthorne-Midway Willow Brook, LLC		
(Hawthorne at the View Apartments)	WR-1496, SUB 0	(09/20/2013)
Laurel Walk Apartments, LLC		
(Laurel Walk Apartments)	WR-1476, SUB 0	(08/13/2013)
Merriwood Associates L. P.		
(Merriwood Apartments)	WR-1447, SUB 0	(06/04/2013)
PC Oxford, LLC		
(Oxford Square Apartments)	WR-1383, SUB 0	(03/04/2013)
Polo Court Apartments, LLC		
(Colonial Village Apartments)	WR-1520, SUB 0	(11/06/2013)
Schrader Family Limited Partnership		
(Cedar Point Apartments)	WR-980, SUB 5	(11/13/2013)
TBR Lake Boone Owner, LLC		
(The Villages of Lake Boone Trail Apts.)	WR-1374, SUB 0	(02/04/2013)
Titan Colony, LLC		
(Colony Apartments)	WR-1395, SUB 1	(09/04/2013)

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RESALE OF WATER AND SEWER -- Miscellaneous

Retreat at Carrington Oaks, LLC – WR-1331, SUB 1; Order Approving Refund Plan *(Carrington Place Apartments)* (01/04/2013)

RESALE OF WATER AND SEWER -- Tariff Revision for Pass-Through

ORDER APPROVING TARIFF REVISION

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Company	Docket No.	Date
Abberly Place – Garner – Phase 1 LP		
(Abberly Place Apartments)	WR-305, SUB 7	(07/23/2013)
Addison Point, LLC		
(Addison Point Apartments)	WR-748, SUB 5	(08/07/2013)
Alaris Village Apartments, LLC		
(Alaris Village Apartments)	WR-894, SUB 4	(01/22/2013)
Alexander Place Apartments, LLC		
(Alexander Place Apartments)	WR-1148, SUB 1	(08/12/2013)
AMFP I Hamilton Ridge, LLC		
(Hamilton Ridge Apartments)	WR-805, SUB 6	(08/02/2013)
AMFP II Four Seasons, LLC		
(Four Seasons at Umstead Park Apts.)	WR-1165, SUB 2	(07/30/2013)
Apartments at Crossroads, LLC; The		
(Legacy Crossroads Apartments)	WR-851, SUB 5	(09/23/2013)
Arbor Village MMXI, LLC		
(Arbor Village Apartments)	WR-1239, SUB 3	(09/09/2013)
Ascot Point Village Apartments, LLC		
(Ascot Point Village Apts.)	WR-273, SUB 9	(01/23/2013)
Ashborough Investors, LLC		
(Ashborough Apartments)	WR-489, SUB 6	(07/26/2013)
Asheville Apartments Investors, LLC		
(Reserve at Asheville Apartments)	WR-1327, SUB 1	(07/31/2013)
Ashford SPE, LLC		
(Ashford Place Apts., Phase I)	WR-555, SUB 8	(07/17/2013)
Ashford SPE 2, LLC		
(Ashford Place Apartments, Phase II)	WR-990, SUB 4	(07/18/2013)
Ashton Village Limited Partnership		
(Abberly Place Apartments, Phase II)	WR-802, SUB 6	(07/23/2013)
Atria at Crabtree Valley Apartments, LLC		
(Atria at Crabtree Valley Apts.)	WR-1093, SUB 1	(08/12/2013)
Atwood, LLC		
(Knollwood Apartments)	WR-1283, SUB 1	(08/27/2013)

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ORDER APPROVING TARIFF REVISION
Orders Issued *(Continued)*

Company	Docket No.	Date
Auston Grove- Raleigh Apartments, LP		
(Auston Grove Apartments)	WR-233, SUB 12	(07/22/2013)
Autumn Park Owner, LLC		
(Autumn Park Charlotte Apts.)	WR-1378, SUB 1	(12/18/2013)
Avalon Apartments DE, LLC		
(Avalon Apartments)	WR-1348, SUB 1	(07/08/2013)
Avery Millbrook, LLC		
(Millbrook Apartments)	WR-1020, SUB 8	(08/06/2013)
(Avery Square Apartments)	WR-1020, SUB 9	(08/06/2013)
Barrington Apartments, LLC		
(Barrington Apartments)	WR-384, SUB 11	(07/29/2013)
BBR/Brookford, LLC		
(Brookford Place Apts.)	WR-614, SUB 7	(11/05/2013)
BBR/Madison Hall, LLC		
(Madison Hall Apartments)	WR-603, SUB 3	(11/05/2013)
Beachwood Associates, LLC		
(Beachwood Park Apartments)	WR-880, SUB 2	(10/07/2013)
Beaver Creek Section I Assoc., LLC		
(Beaver Creek Townhomes Apts. (Sec. I)	WR-881, SUB 2	(10/07/2013)
Beaver Creek Section II Associates, LLC		
(Beaver Creek Townhomes Apts. (Sec. II)	WR-878, SUB 2	(10/08/2013)
Beckanna Partners, LLC		
(Beckanna on Glenwood Apartments)	WR-1460, SUB 1	(08/21/2013)
Bel Hickory Grove Holdings, LLC		
(Kimmerly Glen Apartments)	WR-1054, SUB 3	(08/21/2013)
Bel Pineville Holdings, LLC		
(Berkshire Place Apartments)	WR-1037, SUB 3	(08/19/2013)
Bel Ridge Holdings, LLC		
(McAlpine Ridge Apartments)	WR-1053, SUB 3	(10/21/2013)
Bell Fund IV Morrison Apartments, LLC		
(Bell Morrison Apartments)	WR-1250, SUB 2	(09/17/2013)
Bell Fund IV Morrisville Apartments, LLC		
(Bell Preston View Apts.)	WR-1391, SUB 1	(10/28/2013)
Berrington Village Apartments, LLC		
(Berrington Village Apartments)	WR-1153, SUB 1	(01/22/2013)
BES Ansley Fund IX, LLC		
(Ansley Falls Apartments)	WR-1132, SUB 1	(10/30/2013)
BES Steele Creek Fund IX, LLC, et al.		
(Preserve at Steele Creek Apartments)	WR-1352, SUB 1	(10/22/2013)

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Orders Issued (Continued)

Company	Docket No.	Date
Best Mulch, Inc.		
(Clairmont Crest Mobile HP)	WR-513, SUB 5	(09/16/2013)
BHC-Hawthorne Cambridge, LLC		
(Hawthorne at Commonwealth Apts.)	WR-1381, SUB 1	(08/26/2013)
BHC – Pine Winds, LLC		
(Pine Winds Centerview Apts.)	WR-1242, SUB 1	(11/04/2013)
BMA Eden Apartments, LLC		
(Arbor Glen Apartments)	WR-728, SUB 4	(02/25/2013)
BMA Huntersville Apartments, LLC		
(Huntersville Apartments)	WR-811, SUB 5	(07/30/2013)
BMA Lakewood, LLC		
(Lakewood Apartments)	WR-817, SUB 4	(12/23/2013)
BMA Monroe III, LLC		
(Woodbrook Apartments)	WR-812, SUB 6	(08/02/2013)
BMA North Sharon Amity, LLC		
(Sharon Pointe Apartments)	WR-810, SUB 4	(02/25/2013)
(Sharon Pointe Apartments)	WR-810, SUB 5	(07/30/2013)
BMA Wexford, LLC		
(Wexford Apartments)	WR-813, SUB 5	(07/30/2013)
BNP/Abbington, LLC		
(Abbington Place Apartments)	WR-454, SUB 7	(07/26/2013)
BNP/Pepperstone, LLC		
(Pepperstone Apartments)	WR-445, SUB 8	(07/26/2013)
BNP/Savannah, LLC		
(Savannah Place Apartments)	WR-474, SUB 6	(11/05/2013)
Bouwfonds Pavilion Crossings I, LLC		
(Pavilion Crossings I Apts.)	WR-599, SUB 6	(11/26/2013)
Bouwfonds Pavilion Crossings II, LLC		
(Pavilion Crossings II Apts.)	WR-598, SUB 6	(11/26/2013)
BRC Abernathy, LLC, et al.		
(Abernathy Park Apartments)	WR-1057, SUB 3	(07/16/2013)
BRC Charlotte 485, LLC		
(Halton Park Apartments)	WR-501, SUB 6	(07/17/2013)
BRC Knightdale, LLC		
(Berkshire Park Apartments)	WR-938, SUB 4	(07/16/2013)
BRC Wilson, LLC		
(Thornberry Park Apartments)	WR-502, SUB 3	(10/30/2013)

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Orders Issued (Continued)

Company	Docket No.	Date
Bridgewood Title Partnership		
(Bridgewood Apartments)	WR-132, SUB 7	(02/11/2013)
Brightwood Crossing Apartments, LLC		
(Brightwood Crossing Apts.)	WR-543, SUB 4	(08/21/2013)
BRNA, LLC		
(Bryn Athyn Apartments)	WR-75, SUB 13	(07/29/2013)
Brookberry Park Apartments, LLC		
(Brookberry Park Apartments)	WR-798, SUB 6	(11/04/2013)
Burd Properties Fayetteville, LLC		
(Carlson Bay Apartments)	WR-585, SUB 13	(04/30/2013)
(Stoney Ridge Apartments)	WR-585, SUB 14	(04/30/2013)
(Meadowbrook at King's Grant Apts.)	WR-585, SUB 15	(04/30/2013)
C L Properties of the Carolinas, LLC		
(Hunters Pointe Apartments)	WR-516, SUB 1	(09/30/2013)
Cam Glen Apartments, LLC, et al.		
(Beacon Glen Apartments)	WR-1140, SUB 2	(03/04/2013)
(Beacon Glen Apartments)	WR-1140, SUB 3	(07/30/2013)
Cambridge NC Warwick, LLC		
(Cambridge Apartments)	WR-514, SUB 4	(02/26/2013)
(Cambridge Apartments)	WR-514, SUB 5	(08/26/2013)
Cape Fear Multifamily, LLC		
(The Astoria at Hope Mills Apts.)	WR-1264, SUB 1	(08/14/2013)
Carlyle Centennial Parkside, LLC		
(Century Parkside Apartments)	WR-942, SUB 4	(11/26/2013)
Carolina Village MHC, LLC		
(Carolina Village Mobile Home Park)	WR-1215, SUB 1	(06/10/2013)
Carrington Apartment Properties, LLC		
(Carrington at Brier Creek Apts.)	WR-860, SUB 2	(08/13/2013)
Cary Parkway Marquis, LP		
(Marquis on Cary Parkway Apts.)	WR-522, SUB 7	(08/19/2013)
Cary Towne Park, LLC		
(Legends Cary Towne Apartments)	WR-874, SUB 3	(10/07/2013)
Cato; Charles E.		
(Cato Mobile Home Community)	WR-995, SUB 1	(08/13/2013)
CCC Sommerset Place, LLC		
(Sommerset Place Apartments)	WR-1446, SUB 1	(11/19/2013)
CCC Windsor Falls, LLC		
(Windsor Falls Apartments)	WR-1373, SUB 1	(11/22/2013)

ORDER APPROVING TARIFF REVISION

Orders Issued (Continued)

Company	Docket No.	Date
Cedar Trace, LLC		
(Cedar Trace Apartments)	WR-897, SUB 5	(08/07/2013)
CEG Friendly Manor, LLC		
(Legacy at Friendly Manor Apts.)	WR-266, SUB 6	(07/17/2013)
Centennial Addington Farms, LLC		
(Century Trinity Estates Apts.)	WR-1403, SUB 1	(10/30/2013)
Centennial Centerview, LP		
(Century Centerview Apartments)	WR-1272, SUB 1	(10/30/2013)
CH Realty V/Park and Market, LLC		
(Park and Market Apartments)	WR-1303, SUB 1	(09/17/2013)
Chamberlain Place Apartments, LLC		
(Chamberlain Place Apartments)	WR-819, SUB 4	(12/03/2013)
Chapman; Roy & Betty		
(Twin Willows Mobile Home Park)	WR-1035, SUB 2	(08/12/2013)
Charlotte Apartment Investment, LLC		
(Reserve at Stone Hollow Apts.)	WR-969, SUB 2	(02/18/2013)
City View Apartments, LLC		
(City View at Southside Apts., Phase I)	WR-702, SUB 5	(08/06/2013)
City View Commercial, LLC		
(City View at Southside Apts., Phase II)	WR-1236, SUB 2	(08/06/2013)
CLNL Acquisition Sub, LLC		
(Colonial Village at South Tryon Apts.)	WR-975, SUB 28	(07/11/2013)
(Colonial Village at Stone Pointe Apts.)	WR-975, SUB 29	(07/11/2013)
(Colonial Grand at Legacy Park Apts.)	WR-975, SUB 30	(07/11/2013)
(Colonial Village at Charleston Pl. Apts.)	WR-975, SUB 31	(07/11/2013)
(Colonial Village at Deerfield Apts.)	WR-975, SUB 33	(08/20/2013)
(Colonial Village at Mill Creek Apts.)	WR-975, SUB 34	(11/13/2013)
(Glen Eagles Apartments)	WR-975, SUB 35	(11/13/2013)
CMF 7 Portfolio, LLC		
(Colonial Grand at Huntersville Apts.)	WR-976, SUB 6	(07/12/2013)
(Colonial Village at Greystone Apts.)	WR-976, SUB 7	(07/12/2013)
CMF 15 Portfolio, LLC		
(Mallard Lake Apartments)	WR-955, SUB 18	(07/11/2013)
(Colonial Grand at Mallard Creek Apts.)	WR-955, SUB 19	(07/11/2013)
(Colonial Grand at Beverly Crest Apts.)	WR-955, SUB 20	(07/11/2013)
(Colonial Grand at Arringdon Apts.)	WR-955, SUB 21	(08/20/2013)
(Colonial Grand at Patterson Place Apts.)	WR-955, SUB 22	(08/20/2013)
(Colonial Grand at Crabtree Apts.)	WR-955, SUB 23	(08/27/2013)

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<u>*Orders Issued*</u> *(Continued)*

Company	Docket No.	Date
CMLT 2008-LS1 Guilford Living, LLC		
(Ashley Oaks Apartments)	WR-1407, SUB 1	(07/16/2013)
CND Duraleigh Woods, LLC		
(Duraleigh Woods Apartments)	WR-741, SUB 4	(09/10/2013)
CND Sailboat Bay, LLC		
(Sailboat Bay Apartments)	WR-737, SUB 4	(09/10/2013)
Cogdill; Gregory S. & Narumon F.		
(Rockola Mobile Home Park)	WR-935, SUB 5	(08/12/2013)
CoHeritage Oak Pointe, LLC		
(Oak Pointe Apartments)	WR-1316, SUB 1	(09/12/2013)
Colonial NC, LLC		
(Colonial Townhouse Apartments)	WR-1284, SUB 2	(07/29/2013)
Colonial Realty Limited Partnership, d/b/a Colonial Alabama Limited Partnership		
(Colonial Grand-Ayrsley Apts.)	WR-437, SUB 34	(05/28/2013)
(Colonial Village-Chancellor Park Apts.)	WR-437, SUB 35	(07/10/2013)
(Colonial Grand-Cornelius Apts.)	WR-437, SUB 36	(07/10/2013)
(Colonial Grand-University Center Apts.)	WR-437, SUB 37	(07/10/2013)
(CR at South End Apartments)	WR-437, SUB 38	(07/10/2013)
(Colonial Grand-Matthews Comm. Apts.)	WR-437, SUB 39	(07/10/2013)
(The Enclave Apartments)	WR-437, SUB 40	(07/10/2013)
(Colonial Grand-Ayrsley Apartments)	WR-437, SUB 41	(07/10/2013)
(Colonial Grand-Research Park Apts.)	WR-437, SUB 42	(08/20/2013)
Commonwealth Road Properties, LLC		
(Enclave at Pamaleee Square Apts.)	WR-1069, SUB 3	(07/08/2013)
Concord Five, LLC		
(Carolina Parkway Crossing Apts.)	WR-579, SUB 5	(09/13/2013)
(Coopers Ridge Apartments)	WR-579, SUB 6	(09/13/2013)
Concord Six, LLC		
(Hampton Forest Apartments)	WR-580, SUB 6	(10/23/2013)
(River Park Apartments)	WR-580, SUB 7	(09/13/2013)
(The Village at Brierfield Apts.)	WR-580, SUB 8	(09/13/2013)
(Crossroads at Village Park Apts.)	WR-580, SUB 9	(09/13/2013)
(Alexander Place Apartments)	WR-580, SUB 10	(09/24/2013)
(Forest Ridge Apartments)	WR-580, SUB 11	(09/13/2013)
Cornerstone NC Operating LP		
(Autumn Park Apartments)	WR-973, SUB 2	(08/20/2013)

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Company	Docket No.	Date
Courtney Estates Grand, LLC		
(The Crossings at Alexander Place Apts.)	WR-729, SUB 3	(01/23/2013)
(The Crossings at Alexander Place Apts.)	WR-729, SUB 4	(08/21/2013)
Courtney Estates Holdings, LLC		
(Courtney Estates Apartments)	WR-572, SUB 6	(10/07/2013)
Courtney Reserve Apartments, LLC		
(Courtney Reserve Apartments)	WR-553, SUB 5	(11/05/2013)
Courtney Ridge H E, LLC		
(Courtney Ridge Apartments)	WR-321, SUB 7	(09/10/2013)
CREF Tribute, LLC		
(Tribute Apartments)	WR-1195, SUB 2	(09/17/2013)
Crescent Commons Apartments, LLC		
(Crescent Commons Apartments)	WR-460, SUB 6	(09/17/2013)
Crescent Oaks Apartments, LLC		
(Crescent Oaks Apartments)	WR-465, SUB 6	(08/26/2013)
Crest Brier Creek Apartments, LLC		
(Crest at Brier Creek Apts.)	WR-1429, SUB 1	(09/10/2013)
Crestmont at Ballantyne Apts., LLC		
(Crestmont at Ballantyne Apts.)	WR-335, SUB 9	(07/29/2013)
CRIT-NC Three, LLC		
(Colonial Village at Highland Hills Apts.)	WR-420, SUB 5	(01/07/2013)
CRLP Bruckhaus Street, LLC		
(Colonial Grand at Brier Creek Apts.)	WR-1060, SUB 2	(08/20/2013)
CRLP Crescent Lane, LLC		
(Colonial Village at Matthews Apts.)	WR-977, SUB 3	(07/12/2013)
Crown Ridge Partners, LLC		
(Grand Terraces Apartments)	WR-818, SUB 4	(07/23/2013)
Crowne at Fairlawn Associates, LP		
(Crowne Park Apartments)	WR-1032, SUB 2	(03/05/2013)
Crowne at Polo Associates, LP		
(Crowne Polo Apartments)	WR-1034, SUB 2	(03/05/2013)
Crowne Club Associates, LP		
(Crowne Club Apartments)	WR-1031, SUB 2	(03/05/2013)
Crowne Forest Associates, L. P.		
(Crowne Oaks Apartments)	WR-1030, SUB 2	(03/05/2013)
Crowne Garden Associates, L. P.		
(Crowne Gardens Apartments)	WR-319, SUB 5	(03/06/2013)
CSFB 2007-C2 Summerlyn, LLC		
(Summerlyn Place Apartments)	WR-1302, SUB 2	(07/24/2013)

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Company	Docket No.	Date
CSHV Belmont, LLC		
(The Belmont Apartments)	WR-752, SUB 6	(10/23/2013)
CSP Highland Oaks, LLC		
(Highland Oaks Apartments)	WR-1137, SUB 2	(11/25/2013)
CSP Hunt's View, LLC		
(Hunt's View Apartments)	WR-1217, SUB 2	(09/17/2013)
Cumberland Cove Apartments, LLC		
(Cumberland Cove Apartments)	WR-200, SUB 9	(07/25/2013)
CWSFG 91, LLC, et al.		
(Marquis at Preston Apartments)	WR-1207, SUB 2	(09/05/2013)
Deerwood Apartments, LLC		
(Twin City Apartments)	WR-853, SUB 3	(06/17/2013)
Delta Crossing NC Partners, LLC		
(Delta Crossing Apartments)	WR-1219, SUB 1	(05/13/2013)
(Delta Crossing Apartments)	WR-1219, SUB 2	(11/12/2013)
DLS Kernersville, LLC		
(Abbotts Creek Apartments)	WR-19, SUB 8	(10/30/2013)
Donathan Cary Limited Partnership		
(Hyde Park Apartments)	WR-558, SUB 7	(07/18/2013)
Donathan/Briarleigh Park Properties, LLC		
(Briarleigh Park Apartments)	WR-797, SUB 6	(10/30/2013)
DPR Parc at University Tower, LLC		
(Parc at University Tower Apartments)	WR-1384, SUB 1	(09/09/2013)
DPR Southpoint Crossing, LLC		
(Southpoint Crossing Apartments)	WR-1385, SUB 1	(09/09/2013)
DRA Cypress Pointe, LP		
(Cypress Pointe Apartments)	WR-863, SUB 5	(09/20/2013)
DRA Lodge at Mallard Creek, LP		
(The Lodge at Mallard Creek Apts.)	WR-854, SUB 5	(09/20/2013)
DRA Quad, LP		
(Quad Apartments)	WR-871, SUB 4	(09/20/2013)
DRA Woodland Park, LP		
(Woodland Park Apartments)	WR-861, SUB 4	(09/20/2013)
Dry Ridge Properties, LLC, et al.		
(Mountain View Mobile HP)	WR-867, SUB 2	(09/03/2013)
Duckett; Gordon F., Jr. & Susan C.		
(Forest Ridge Mobile Home Park)	WR-928, SUB 5	(09/03/2013)
Durham Mews Section II Associates, LLC		
(The Mews Apartments, Section II)	WR-884, SUB 2	(10/01/2013)
Durham Section I Associates, LLC		
(The Mews Apartments, Sec. I)	WR-883, SUB 2	(10/02/2013)

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Orders Issued *(Continued)*

Company	Docket No.	Date
Eagle Point Village Apartments, LLC		
(Eagle Point Village Apartments)	WR-671, SUB 4	(01/23/2013)
East Pointe Partners, LLC		
(Stanford Reserve Apartments)	WR-966, SUB 3	(07/23/2013)
Echo Forest, LLC		
(Legacy Arboretum Apartments)	WR-368, SUB 9	(07/29/2013)
EEA-North Pointe, LLC		
(Sherwood Station Apartments)	WR-1028, SUB 2	(11/04/2013)
EEA-Wildwood, LLC		
(Wildwood Apartments)	WR-629, SUB 5	(09/13/2013)
Elizabeth Square Acquisition Corporation		
(Elizabeth Square Apartments)	WR-1086, SUB 2	(09/09/2013)
ELPF Station Nine, LLC		
(Station Nine Apartments)	WR-724, SUB 5	(09/10/2013)
Erwin Hills Park, LLC		
(Erwin Hills Mobile Home Park)	WR-946, SUB 4	(08/12/2013)
Estates at Charlotte I, LLC		
(1420 Magnolia Apartments)	WR-73, SUB 5	(08/21/2013)
Ethan Pointe, LLC		
(Ethan Pointe Apartments)	WR-744, SUB 3	(09/04/2013)
Evergreens at Mt. Moriah, LLC		
(Evergreens at Mt. Moriah Apts.)	WR-306, SUB 6	(10/07/2013)
Ewing; Roy & Frances		
(Pine Valley Mobile Home Park)	WR-994, SUB 4	(09/03/2013)
EWT 21, LLC		
(Wingate Townhouse Apartments)	WR-1354, SUB 1	(09/09/2013)
Fairfield Chason Ridge, LLC		
(Chason Ridge Apartments)	WR-1414, SUB 1	(08/13/2013)
Fairfield Fairington, LLC		
(The Fairington Apartments)	WR-1418, SUB 1	(09/04/2013)
Fairfield Hamptons, LLC		
(The Hamptons at Southpark Apartments)	WR-1422, SUB 1	(08/01/2013)
Fairfield Mallard I, LLC		
(Bridges at Mallard Creek Apts., Phase I)	WR-1425, SUB 1	(08/01/2013)
Fairfield Mallard II, LLC		
(Bridges at Mallard Creek Apts., Phase II)	WR-1415, SUB 1	(08/01/2013)
Fairfield Marina Shores, LLC		
(Marina Shores Waterfront Apts.)	WR-1420, SUB 1	(08/01/2013)

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Company	Docket No.	Date
Fairfield Oakbrook, LLC		
(Oakbrook Apartments)	WR-1423, SUB 1	(09/04/2013)
Fairfield Olde Raleigh, LLC		
(Olde Raleigh Apartments)	WR-552, SUB 7	(08/27/2013)
Fairfield Paces Commons, LLC		
(Paces Commons Apartments)	WR-1427, SUB 1	(08/01/2013)
Fairfield Quail Hollow, LLC		
(Bridges at Quail Hollow Apartments)	WR-1413, SUB 1	(09/04/2013)
Fairfield Southpoint, LLC		
(Bridges at Southpoint Apartments)	WR-1419, SUB 1	(09/11/2013)
Fairway Apartments, LLC; The, et al.		
(The Links Apartments)	WR-565, SUB 4	(09/10/2013)
Falls River Apartments, LLC		
(Bell Falls River Apartments)	WR-1110, SUB 3	(09/16/2013)
FASF, LLC		
(Cedar Trace IV Apartments)	WR-999, SUB 4	(08/07/2013)
FC Meadowbrook, LLC		
(Meadowbrook Mobile HP)	WR-280, SUB 5	(08/13/2013)
FCP West Village Phase I Owner, LLC		
(West Village Apartments)	WR-1251, SUB 2	(09/17/2013)
Featherstone Village Apartments, LLC		
(Featherstone Village Apartments)	WR-375, SUB 6	(01/23/2013)
Forest at Asheville Properties, LLC; The		
(Bell Forest at Biltmore Park Apts.)	WR-20, SUB 8	(09/16/2013)
Forest Hill Apartments, LLC		
(The Reserve at Forest Hills Apts.)	WR-34, SUB 9	(07/01/2013)
Forest MMXII, LLC		
(Copper Creek Apartments)	WR-1367, SUB 1	(09/09/2013)
Forestdale Apartments, LLC		
(Hawthorne at Forestdale Apts.)	WR-1181, SUB 3	(02/11/2013)
(Hawthorne at Forestdale Apts.)	WR-1181, SUB 4	(09/11/2013)
Fortress Park, LLC		
(The Park Apartments)	WR-1193, SUB 3	(09/12/2013)
Fortune Bay Associates, LLC		
(Forest Pointe Apartments)	WR-785, SUB 6	(09/30/2013)
Foxrun Ridge Limited Partnership		
(Ridge Run Apartments)	WR-146, SUB 2	(07/17/2013)
Fuller Street Development, LLC		
(West Village Expansion Apartments)	WR-726, SUB 4	(09/18/2013)

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Orders Issued (Continued)

Company	Docket No.	Date
Fund II Meadows, LLC, et al.		
(The Meadows Apartments)	WR-846, SUB 5	(09/20/2013)
Fund III Brassfield Park Apartments, LLC		
(Bell Brassfield Apartments)	WR-1038, SUB 2	(09/16/2013)
Fund III Bridford Apartments, LLC		
(Bell Bridford Apartments)	WR-1120, SUB 2	(09/16/2013)
Fund III Cranbrook Apartments, LLC, et al.		
(Bell Biltmore Park Apartments)	WR-1076, SUB 3	(09/16/2013)
Fund IX CP Charlotte, LLC		
(Matthews Crossing Apartments)	WR-691, SUB 6	(01/08/2013)
(Matthews Crossing Apartments)	WR-691, SUB 7	(10/28/2013)
Fund IX PR Durham, LLC		
(Pinnacle Ridge Apartments)	WR-518, SUB 6	(01/08/2013)
(Pinnacle Ridge Apartments)	WR-518, SUB 7	(10/01/2013)
G&I VI Cape Harbor, LP		
(Cape Harbor Apartments)	WR-763, SUB 5	(09/19/2013)
G&I VI Clear Run, LP		
(Clear Run Apartments)	WR-762, SUB 6	(09/19/2013)
G&I VI Copper Mill, LP		
(Copper Mill Apartments)	WR-767, SUB 7	(09/19/2013)
G&I VI Courtney, LP		
(Courtney Place Apartments)	WR-775, SUB 8	(09/20/2013)
G&I VI Crossing, LP		
(Crossing at Quail Hollow Apartments)	WR-764, SUB 7	(09/19/2013)
G&I VI Crosswinds, LP		
(Crosswinds Apartments)	WR-772, SUB 6	(09/19/2013)
G&I VI Forest Hills, LP		
(Forest Hills Apartments)	WR-968, SUB 4	(09/20/2013)
G&I VI Harris Pond, LP		
(Harris Pond Apartments)	WR-771, SUB 7	(09/19/2013)
G&I VI Lake Lynn, LP		
(The Reserve at Lake Lynn Apts.)	WR-761, SUB 8	(09/19/2013)
G&I VI Mallard, LP		
(Mallard Creek Apartments)	WR-776, SUB 7	(09/20/2013)
G&I VI Meadows at Kildare, LP		
(Meadows at Kildare Apartments)	WR-769, SUB 7	(09/19/2013)
G&I VI Mill Creek, LP		
(Mill Creek Apartments)	WR-774, SUB 6	(09/20/2013)

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Company	Docket No.	Date
G&I VI Norcroft, LP		
(Northlake Apartments)	WR-768, SUB 7	(09/19/2013)
G&I VI Oaks at Weston, LP		
(Oaks at Weston Apartments)	WR-778, SUB 7	(09/20/2013)
G&I VI Providence Court, LP		
(Providence Court Apartments)	WR-758, SUB 7	(09/18/2013)
G&I VI Spring Forest, LP		
(Spring Forest Apartments)	WR-766, SUB 8	(09/19/2013)
G&I VI The Creek, LP		
(The Creek Apartments)	WR-770, SUB 12	(09/19/2013)
(Sharon Crossing Apartments)	WR-770, SUB 13	(09/19/2013)
G&I VI Trinity Park, LP		
(Trinity Park Apartments)	WR-773, SUB 8	(09/19/2013)
G&I VI Walnut Creek, LP		
(Walnut Creek Apartments)	WR-777, SUB 8	(09/20/2013)
Garrett Farms Apartments, LP		
(Alexan Garrett Farms Apartments)	WR-1023, SUB 3	(04/22/2013)
Gateway Communities, LLC/Park Regency, LLC		
(Arwen Vista Apartments)	WR-948, SUB 2	(05/13/2013)
GECMC 2007-C1 Treetop Drive, LLC		
(Cumberland Trace Apartments)	WR-1126, SUB 2	(06/17/2013)
Genesis Partners, LLC		
(Treeside Mobile Home Park)	WR-323, SUB 9	(08/13/2013)
GGT Whitehall Venture NC, LLC		
(Whitehall Parc Apartments)	WR-1338, SUB 1	(11/19/2013)
Golden Triangle #3, LLC		
(Carmel on Providence Apts.)	WR-1439, SUB 1	(07/25/2013)
Grace Park Development, LLC		
(Grace Park Apartments)	WR-893, SUB 4	(10/03/2013)
Gray Woodfield Glen, LLC		
(Woodfield Glen Apartments)	WR-1141, SUB 2	(01/14/2013)
(Woodfield Glen Apartments)	WR-1141, SUB 3	(10/02/2013)
Greenfield Village NC, LLC		
(Greenfield Village Mobile Home Park)	WR-954, SUB 2	(12/18/2013)
Greentree Real Estate Services, LLC		
(The Highland Apartments)	WR-1416, SUB 1	(08/27/2013)
Greenville Village, LLC		
(Greenville Village Mobile HP)	WR-648, SUB 5	(07/31/2013)
Greenway at Fisher Park, LLC		
(Greenway at Fisher Park Apartments)	WR-1322, SUB 1	(04/29/2013)

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Company	Docket No.	Date
Greystone WW Company, LLC		
(Greystone at Widewaters Apartments)	WR-517, SUB 5	(07/26/2013)
GS Edinborough Commons, LLC		
(Edinborough Commons Apartments)	WR-475, SUB 8	(09/23/2013)
GS Edinborough Park, LLC		
((Edinborough at the Park Apartments)	WR-476, SUB 6	(10/02/2013)
GS Village, LLC		
(The Village Apartments)	WR-564, SUB 8	(09/18/2013)
Guardian Tryon Village, LLC		
(Windsor at Tryon Village Apts.)	WR-1335, SUB 1	(11/26/2013)
Guardian Wakefield, LLC		
(Wakefield Apartments)	WR-1337, SUB 1	(12/02/2013)
Hampton Ridge Partners, LLC		
(Victoria Park Apartments)	WR-901, SUB 4	(07/23/2013)
Hanover Terrace, LLC		
(Hanover Terrace Apartments)	WR-622, SUB 6	(09/13/2013)
Harris Pointe, LLC		
(Harris Pointe Apartments)	WR-756, SUB 3	(02/12/2013)
Hawthorne-Midway Madison Place, LLC		
(Madison Place Apartments)	WR-1300, SUB 2	(12/27/2013)
Hawthorne-Midway Meadows, LLC		
(Hawthorne at the Meadows Apts.)	WR-1307, SUB 2	(12/27/2013)
Hawthorne-Midway Summerwood, LLC		
(Summerwood Apartments)	WR-1194, SUB 3	(12/27/2013)
Heinmiller; Arthur E. & Florence H.		
(Apple Blossom Mobile Home Park)	WR-1094, SUB 2	(08/12/2013)
Heinmiller Investments, LLC		
(Broadview Mobile Home Park)	WR-1092, SUB 3	(08/01/2013)
Heritage Arden I, LLC, et al.		
(Arden Woods Apartments)	WR-1298, SUB 1	(09/12/2013)
Heritage Williamsburg I, LLC, et al.		
(Williamsburg Manor Apartments)	WR-1299, SUB 1	(09/12/2013)
Hickory Grove NC Partners, LLC		
(Cameron at Hickory Grove Apts.)	WR-1435, SUB 1	(11/12/2013)
Hidden Creek Village Apartments, LLC		
(Hidden Creek Village Apartments)	WR-377, SUB 6	(01/23/2013)
Highland Quarters, LLC		
(Muirfield Village Apartments)	WR-520, SUB 7	(08/19/2013)
Holly Hill Properties, LLC		
(Holly Hill Apartments)	WR-192, SUB 7	(09/17/2013)

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Company	Docket No.	Date
Holly NC, LLC		
(Holly Hills Apartments)	WR-1290, SUB 2	(07/29/2013)
HTC Preston Reserve, LLC, et al.		
(Bell Preston Reserve Apartments)	WR-1180, SUB 2	(09/17/2013)
Huntington, LLC		
(Huntington Apartments)	WR-199, SUB 2	(09/23/2013)
Inman Park Investment Group, Inc.		
(Inman Park Apartments)	WR-383, SUB 10	(07/31/2013)
Integra Springs, LLC		
(Integra Springs at Kellswater Apts.)	WR-1036, SUB 3	(12/09/2013)
JLB Southline, LLC		
(Junction 1504 Apartments)	WR-1326, SUB 1	(11/12/2013)
Joslin Realty, Inc.		
(Grove Park Apartments)	WR-151, SUB 8	(07/31/2013)
KC Realty Investments, LLC		
(Woodland Heights Mobile Home Park)	WR-950, SUB 4	(08/12/2013)
Kings Park, LLC		
(Redcliffe at Kenton Place Apts.)	WR-349, SUB 10	(08/12/2013)
Kingswood NC, LLC		
(Kingswood Mobile Home Park)	WR-987, SUB 2	(12/18/2013)
Kip-Dell Homes, Inc.		
(Clover Lane Townehomes)	WR-341, SUB 2	(09/12/2013)
Knickerbocker Properties, Inc. XX		
(Cheswyck at Ballantyne Apartments)	WR-109, SUB 14	(03/19/2013)
KPCLIC, LLC		
(Millbrook Green Apartments)	WR-573, SUB 6	(09/10/2013)
Kubeck; Bruce A.		
(Faircrest Mobile Home Park)	WR-310, SUB 30	(07/31/2013)
Lakeshore Apartments, LLC		
(The Lodge at Lakeshore Apartments)	WR-649, SUB 5	(08/06/2013)
Landmark at Chesterfield, LP		
(Landmark at Chesterfield Apts.)	WR-1174, SUB 2	(07/23/2013)
LaSalle NC, LLC		
(Duke Manor Apartments)	WR-1286, SUB 2	(07/29/2013)
Laurel Wood Associates, LLC		
(Laurel Wood Mobile Home Park)	WR-1045, SUB 3	(09/03/2013)
Lees Chapel Partners, LLC		
(Millbrook Apartments 2)	WR-875, SUB 15	(08/07/2013)
(Chapel Walk Apartments)	WR-875, SUB 16	(08/07/2013)
(Cross Creek Apartments)	WR-875, SUB 17	(08/07/2013)

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Company	Docket No.	Date
Legacy at Twin Oaks, LLC		
(Twin Oaks Apartments)	WR-1353, SUB 1	(07/17/2013)
Legacy Cornelius, LLC		
(Legacy Cornelius Apartments)	WR-1388, SUB 1	(07/29/2013)
Legacy Matthews, LLC		
(Legacy Matthews Apartments)	WR-568, SUB 7	(07/30/2013)
Legacy Oaks Apartments, LP		
(Alta Legacy Oaks Apartments)	WR-972, SUB 5	(09/10/2013)
Legends at Hickory, LLC; The		
(The Legends Apartments)	WR-1409, SUB 1	(08/06/2013)
Lenoxplace Apartments, LLC		
(Lenox at Garners Station Apartments)	WR-1305, SUB 1	(08/26/2013)
Lincoln Green Apartments, LLC		
(Lincoln Green Apartments)	WR-527, SUB 5	(09/18/2013)
Litchford Park, LLC		
(The Park at North Ridge Apartments)	WR-588, SUB 7	(09/18/2013)
Lofts at Charlestown Row, LLC; The		
(The Lofts at Charleston Row Apts.)	WR-1313, SUB 1	(09/05/2013)
Lofts at Reynolds Village, LLC; The		
(The Lofts at Reynolds Village Apts.)	WR-1178, SUB 1	(05/06/2013)
(The Lofts at Reynolds Village Apts.)	WR-1178, SUB 2	(08/20/2013)
Lofts SREF at Lakeview, Inc.		
(Lofts at Lakeview Apartments)	WR-780, SUB 3	(03/19/2013)
Lone Oak, LLC		
(Lone Oak Mobile Home Park)	WR-1084, SUB 2	(09/09/2013)
Long Creek Club Apartments, LLC		
(Long Creek Apartments)	WR-866, SUB 5	(08/05/2013)
Longview at Northlake, LLC		
(Longview Apartments)	WR-1170, SUB 2	(08/06/2013)
LVP Timber Creek, LLC		
(Beacon Timber Creek Apartments)	WR-717, SUB 6	(08/28/2013)
LVP Wendover, LLC		
(Camden Wendover Apartments)	WR-719, SUB 5	(08/05/2013)
M Realty, LLC		
(Wellington Mobile Home Park)	WR-1040, SUB 2	(07/08/2013)
Madison Properties, Inc.		
(673 Sand Hill Road Apartments)	WR-1380, SUB 3	(08/01/2013)
(Pinewood Apartments)	WR-1380, SUB 4	(08/01/2013)
Maggard; David		
(Quiet Hollow Mobile Home Park)	WR-632, SUB 4	(09/03/2013)

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Company	Docket No.	Date
Mallard Green, LLC		
(Mallard Green Apartments)	WR-1259, SUB 2	(07/31/2013)
Marsh Realty Company		
(Park Place Apartments)	WR-1154, SUB 6	(07/22/2013)
(Biscayne Apartments)	WR-1154, SUB 7	(07/22/2013)
(Briarcreek Apartments)	WR-1154, SUB 8	(07/22/2013)
Mayfaire Apartments, LLC		
(Mayfaire Apartments)	WR-345, SUB 5	(09/12/2013)
MB Remington Place, LLC		
(Remington Place Apartments)	WR-461, SUB 7	(09/17/2013)
MB The Timbers, LLC		
(The Timbers Apartments)	WR-462, SUB 7	(09/17/2013)
McArthur Partners, LLC		
(The Heights at McArthur Park Apts.)	WR-1292, SUB 1	(07/17/2013)
McArthur Partners II, LLC		
(The Heights at McArthur Park Apts.)	WR-1124, SUB 2	(07/16/2013)
Meridian at Wakefield, LLC		
(Meridian at Wakefield Apartments)	WR-1098, SUB 3	(09/16/2013)
Mid-America Apartmens, L. P.		
(Waterford Forest Apartments)	WR-22, SUB 55	(10/21/2013)
(Providence at Brier Creek Apartments)	WR-22, SUB 56	(10/21/2013)
(Hue Apartments)	WR-22, SUB 57	(10/21/2013)
(Hermitage at Beechtree Apartments)	WR-22, SUB 58	(10/21/2013)
(Brier Creek Apts., Phases I & II)	WR-22, SUB 59	(10/21/2013)
Morganton Trading Company L. P.		
(Morganton Trading Company Apts.)	WR-548, SUB 2	(03/18/2013)
Morreene, LLC		
(Chapel Tower Apartments)	WR-1289, SUB 2	(07/29/2013)
Morrisville Associates, LLC		
(Crabtree Crossing Townhomes Apts.)	WR-879, SUB 2	(09/30/2013)
Moss; Allen H.		
(Crestview II Mobile Home Park)	WR-896, SUB 7	(08/19/2013)
(Maple Terrace Mobile Home Park)	WR-896, SUB 8	(08/19/2013)
(Crestview II Mobile Home Park)	WR-896, SUB 9	(11/04/2013)
Moss Enterprises, Inc. of Asheville		
(Crownpointe Mobile Home Park)	WR-924, SUB 8	(08/19/2013)
(Mosswood/Twin Oaks Mobile HP)	WR-924, SUB 9	(08/19/2013)
(Mosswood/Twin Oaks Mobile HP)	WR-924, SUB 10	(11/04/2013)
(Crownpointe Mobile Home Park)	WR-924, SUB 11	(11/04/2013)

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Company	Docket No.	Date
Mosteller Apartments, LLC		
(Estates at Legends Apartments)	WR-1404, SUB 1	(08/06/2013)
Motley; Clyde J. & Carl K. Winkler		
(Indian Creek Mobile Home Park)	WR-1072, SUB 2	(09/04/2013)
Motley; Clyde J. & Sharon K.		
(Locust Grove Mobile Home Park)	WR-1071, SUB 2	(09/04/2013)
MP Creekwood, LLC		
(Village Lakes Apartments)	WR-738, SUB 5	(09/18/2013)
MP Cross Creek, LLC		
(Sardis Place at Matthews Apts.)	WR-736, SUB 5	(09/18/2013)
MP Hunt Club, LLC		
(Hunt Club Apartments)	WR-735, SUB 5	(09/18/2013)
MP Regatta, LLC		
(Regatta at Lake Lynn Apartments)	WR-1318, SUB 1	(09/17/2013)
MP Regency Place, LLC		
(Regency Place Apartments)	WR-714, SUB 8	(09/18/2013)
MP The Oaks, LLC		
(The Oaks Apartments)	WR-734, SUB 5	(09/18/2013)
MP The Pointe, LLC		
(The Pointe Apartments)	WR-733, SUB 5	(09/18/2013)
MP The Regency, LLC		
(The Regency Apartments)	WR-740, SUB 5	(09/18/2013)
MP Winterwood, LLC		
(Aspen Peak Apartments)	WR-739, SUB 5	(09/18/2013)
MRP Laurel Oaks, LLC		
(Laurel Oaks Apartments)	WR-507, SUB 3	(12/03/2013)
MRP Laurel Springs, LLC		
(Laurel Springs Apartments)	WR-506, SUB 4	(11/25/2013)
MRWR, LLC		
(Atrium Apartments)	WR-832, SUB 6	(07/30/2013)
MSS Apartments, LLC		
(Main Street Square Apartments)	WR-936, SUB 1	(11/04/2013)
MV/ALG River Crossing Limited, LLC		
(River Crossing Apartments)	WR-164, SUB 7	(02/18/2013)
MV/ALG Steele Creek Limited, LLC		
(Landings at Steele Creek I Apts.)	WR-227, SUB 5	(02/18/2013)
MV/ALG Twin Cedars Limited, LLC		
(Twin Cedars I Apartments)	WR-226, SUB 6	(02/18/2013)
New Haw Creek Associates		
(Haw Creek Mews I Apartments)	WR-624, SUB 2	(10/02/2013)
New Haw Creek Section II Associates		
(Haw Creek Mews II Apartments)	WR-625, SUB 2	(10/02/2013)

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Company	Docket No.	Date
New Park Ridge Associates, LLC		
(Park Ridge Estates Apartments)	WR-1225, SUB 2	(07/24/2013)
New Willow Ridge Associates, LLC		
(Willow Ridge Apartments)	WR-212, SUB 5	(07/26/2013)
Neyland Apartment Associates Two, LLC		
(Independence Park Apartments)	WR-1214, SUB 2	(09/12/2013)
Nicholas; Ruby Lea		
(Woodcrest Mobile HP)	WR-249, SUB 6	(04/01/2013)
North Carolina Rental Parks Assoc., Limited		
(Whispering Pines Mobile Home Park)	WR-1070, SUB 3	(08/01/2013)
Northlake Residential Associates, LLC		
(Madison Square at Northlake Apts.)	WR-1361, SUB 1	(09/09/2013)
Northwestern Mutual Life Insurance Co., d/b/a Trinity Commons; The		
(Trinity Commons at Erwin Apts.)	WR-1517, SUB 1	(11/12/2013)
Norwalk Street Partners, LLC		
(Andover Park Apartments)	WR-653, SUB 5	(07/18/2013)
NR St. Mary's Property Owners, LLC		
(St Mary's Square Apartments)	WR-1444, SUB 1	(10/07/2013)
One Hilltop, LLC		
(Hilltop Mobile Home Park)	WR-1077, SUB 2	(08/12/2013)
PAMI Grand Oaks, LLC		
(Grand Oaks Apartments)	WR-1347, SUB 1	(09/12/2013)
Park at Clearwater, LLC		
(Park at Clearwater Apts., Phases I & II)	WR-1167, SUB 2	(10/22/2013)
Park Commons MMXII, LLC		
(Parkland Commons Apartments)	WR-1366, SUB 1	(09/09/2013)
Park Forest Triad Apt. Portfolio, LLC		
(Park Forest Apartments)	WR-493, SUB 5	(09/17/2013)
Parkside Drive, LLC		
(CG at Brier Falls Apartments)	WR-1218, SUB 2	(08/20/2013)
PC Links, LLC		
(Links at Citiside Apartments)	WR-1149, SUB 3	(07/24/2013)
Penwood Associates, LLC		
(Penwood Apartments)	WR-1448, SUB 1	(07/25/2013)
Perimeter Station, LLC		
(Perimeter Station Apartments)	WR-914, SUB 3	(11/26/2013)
Pier Properties, LLC		
(Grassy Branch Mobile Home Park)	WR-1138, SUB 1	(09/05/2013)
Pine Knoll Mobile Home Park, LLC		
(Pine Knoll Mobile Home Park)	WR-1434, SUB 1	(12/02/2013)

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Company	Docket No.	Date
Piper Station Apartments, LLC		
(Piper Station Apartments)	WR-1432, SUB 1	(12/23/2013)
Plantation Park Apartments, Inc.		
(Plantation Park Apartments)	WR-644, SUB 6	(09/10/2013)
Pleasant Garden Apartments, LLC		
(The Gardens at Anthony House Apts.)	WR-742, SUB 5	(08/07/2013)
POAA II, LLC		
(Pines of Ashton Apartments)	WR-1282, SUB 2	(07/29/2013)
Post Apartment Homes, LP		
(Post Uptown Place Apartments)	WR-49, SUB 14	(10/22/2013)
(Post Park at Phillips Place Apts.)	WR-49, SUB 15	(10/31/2013)
Post South End, LP		
(Post South End Apartments)	WR-1326, SUB 1	(11/05/2013)
PRG Bainbridge Associates, LLC		
(Bainbridge in the Park Apts.)	WR-1356, SUB 1	(07/25/2013)
PRG Windsor Square Associates, LLC		
(South Square Townhomes Apts.)	WR-1226, SUB 2	(07/24/2013)
Princeton Marquis, LP		
(The Marquis on Edwards Mill Apts.)	WR-503, SUB 6	(10/01/2013)
Princeton Park Apartments, LLC		
(Legacy North Hills Apartments)	WR-541, SUB 9	(07/29/2013)
Privet Asheville, LLC		
(Eastwood Village Apartments)	WR-1320, SUB 1	(10/28/2013)
Providence Park Apartments, I, LLC		
(Providence Park Apartments)	WR-284, SUB 10	(07/22/2013)
Rackley; Thomas Newell & Johanna Page		
(Buck's Mobile Home Park)	WR-1437, SUB 1	(09/03/2013)
RAIA Properties NC-2, LLC		
(Birkdale Apartment Homes)	WR-839, SUB 6	(08/02/2013)
RAIA Properties NC-4, LLC		
(One Norman Apartments)	WR-1271, SUB 2	(08/01/2013)
RAIA Self-Storage Montville, LLC, et al.		
(The Enclave at Crossroads Apts.)	WR-890, SUB 7	(08/02/2013)
Ramsey; Emmett		
(Emma Hills Mobile Home Park)	WR-796, SUB 4	(09/03/2013)
Red Chief, LLC		
(Morehead Apartments)	WR-722, SUB 4	(09/24/2013)
REEP-MF Verde NC, LLC		
(North City 6 Apartments)	WR-1087, SUB 3	(09/09/2013)
Reserve at Mayfaire, LLC; The		
(The Reserve at Mayfaire Apts.)	WR-387, SUB 5	(10/28/2013)

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Company	Docket No.	Date
RFI Highlands, LLC		
(The Highlands/Alexander Pointe Apts.)	WR-1294, SUB 1	(12/23/2013)
Richardson; John R., Real Estate IRA, LLC		
(245 Weaverville Hwy. Mobile HP)	WR-1133, SUB 1	(08/01/2013)
Ridge at Highland Creek, LLC		
(The Ridge at Highland Creek Apts.)	WR-1392, SUB 1	(08/19/2013)
Ridgeview MHP, LLC		
(Ridgeview Mobile Home Park)	WR-712, SUB 5	(08/02/2013)
Riverbend of Asheville, LLC		
(Verde Vista Apartments)	WR-1296, SUB 1	(09/23/2013)
Riverwoods Raleigh Apartments, LLC		
(Sterling Forest Apartments)	WR-1112, SUB 2	(03/18/2013)
(Sterling Forest Apartments)	WR-1112, SUB 3	(08/21/2013)
Robinhood Court Apartment Homes, LLC		
(Robinhood Court Apartments)	WR-1051, SUB 4	(11/26/2013)
Rockwood Road Apts., LLC		
(Audubon Place Apartments)	WR-964, SUB 3	(08/13/2013)
Salem Ridge Apartments, LLC		
(Salem Ridge Apartments)	WR-1096, SUB 3	(11/05/2013)
Salem Village Apartments, LLC		
(Salem Village Apartments)	WR-446, SUB 7	(07/23/2013)
SBV-Greensboro-I, LLC		
(Misty Creek Apartments II)	WR-1471, SUB 3	(09/03/2013)
(Misty Creek Apartments I)	WR-1471, SUB 4	(09/03/2013)
SC Waterford Hills, LLC		
(Waterford Hills Apartments)	WR-1061, SUB 2	(09/30/2013)
Seagrove Village MHP, LLC		
(Seagrove Village Mobile Home Park)	WR-1297, SUB 1	(12/16/2013)
Selona Partners, LLC		
(Waterstone at Brier Creek Apts.)	WR-1438, SUB 1	(08/05/2013)
(Waterstone at Brier Creek Apts.)	WR-1438, SUB 2	(11/20/2013)
SH Pool A Sunstone, LLC		
(Sunstone Apartments)	WR-694, SUB 5	(11/13/2013)
Sherwood MHP, LLC		
(Sherwood Mobile Home Park)	WR-1044, SUB 3	(08/01/2013)
SHLP Chancery Village, LLC		
(Chancery Village at the Park Apts.)	WR-1204, SUB 1	(05/20/2013)
(Chancery Village at the Park Apts.)	WR-1204, SUB 2	(07/22/2013)
SHLP Gramercy Square at Ayrsley, LLC		
(Gramercy Square at Ayrsley Apts.)	WR-1184, SUB 1	(05/20/2013)
(Gramercy Square at Ayrsley Apts.)	WR-1184, SUB 2	(07/16/2013)

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Company	Docket No.	Date
Shoreline, LLC		
(Long Leaf Mobile Home Park)	WR-530, SUB 3	(03/11/2013)
Silverton Marquis, LP		
(Marquis at Silverton Apartments)	WR-422, SUB 9	(09/11/2013)
Simpson Financing L. P.		
(The Arboretum Apartments)	WR-276, SUB 1	(05/20/2013)
(The Arboretum Apartments)	WR-276, SUB 2	(07/17/2013)
Simpson Promenade Park, LLC		
(Promenade Park Apartments)	WR-876, SUB 1	(05/21/2013)
(Promenade Park Apartments)	WR-876, SUB 2	(07/18/2013)
South End Apartments, LLC		
(The Millennium South End Apts.)	WR-1173, SUB 2	(09/09/2013)
South Square Owner, LLC		
(Alden Place at South Square Apts.)	WR-1387, SUB 1	(08/12/2013)
Southbridge Multifamily, LLC		
(Stillwater at Southbridge Apartments)	WR-1390, SUB 0	(08/28/2013)
Southwood Realty Company		
(Quail Woods Apartments)	WR-910, SUB 13	(12/23/2013)
(Carriage House Apartments)	WR-910, SUB 14	(12/23/2013)
Spring Ridge Apartments, LLC		
(Spring Ridge Apartments)	WR-725, SUB 3	(02/26/2013)
(Spring Ridge Apartments)	WR-725, SUB 4	(09/23/2013)
Spyglass Capital Partners-Hawk Ridge, LLC		
(Hawk Ridge Apartments)	WR-1182, SUB 2	(03/04/2013)
(Hawk Ridge Apartments)	WR-1182, SUB 3	(12/09/2013)
SRC Northwinds, Inc.		
(Northwinds I and II Apartments)	WR-1254, SUB 2	(08/05/2013)
St. Andrews Place Apartments, LLC		
(Colonial Grand at Wilmington Apts.)	WR-111, SUB 9	(06/10/2013)
Steele Creek Apartments, L. P.		
(Landings at Steele Creek II Apts.)	WR-228, SUB 5	(02/18/2013)
Steeplechase Triad Apt. Portfolio, LLC		
(Steeplechase Apartments)	WR-497, SUB 5	(09/17/2013)
Strawberry Hill Associates, LP		
(Strawberry Hills Apartments)	WR-293, SUB 8	(07/23/2013)
Strickland Farms Apartments, LLC		
(Strickland Farms Apartments)	WR-1304, SUB 2	(08/26/2013)
Summit Allerton, LLC		
(Allerton Place Apartments)	WR-1280, SUB 1	(11/05/2013)
Suncoast North Park, LLC		
(North Park Apartments)	WR-808, SUB 6	(08/02/2013)

ORDER APPROVING TARIFF REVISION

Orders Issued (Continued)

Company	Docket No.	Date
Sureties Unlimited 2, LLC		
(Pinewood Trace Apartments)	WR-1377, SUB 1	(10/03/2013)
SVF Weston Lakeside, LLC		
(Apartments at Weston Lakeside)	WR-601, SUB 6	(09/10/2013)
Sweetwater Meadows, LLC		
(Sweetwater Meadows Mobile HP)	WR-1375, SUB 1	(10/07/2013)
Talbert Woods Mooresville Section I, LLC		
(Talbert Woods Townhomes I Apts.)	WR-1358, SUB 1	(10/02/2013)
Talbert Woods Mooresville Section II, LLC		
(Talbert Woods Townhomes II Apts.)	WR-1359, SUB 1	(10/01/2013)
Tanglewood Lake Apts., LLC		
(Tanglewood Lake Apartments)	WR-1015, SUB 1	(04/01/2013)
Terrace Mews, LLC		
(Terrace at Olde Battleground Apts.)	WR-1394, SUB 1	(09/04/2013)
Thornwood Village, LLC		
(Thornwood Village Mobile HP)	WR-1001, SUB 2	(08/12/2013)
Three Oak Property, LLC		
(The Park at Three Oaks Apartments)	WR-405, SUB 2	(08/26/2013)
TIC Adams Farm, LLC, et al.		
(The Madison at Adams Farm Apts.)	WR-667, SUB 2	(02/25/2013)
(The Madison at Adams Farm Apts.)	WR-667, SUB 3	(10/01/2013)
TIC Bridford Lake, LLC, et al.		
(Bridford Lake Apartments)	WR-666, SUB 2	(02/25/2013)
(Bridford Lake Apartments)	WR-666, SUB 3	(10/01/2013)
Tiger Properties III, LLC		
(Arbor Creek Apartments)	WR-1102, SUB 2	(07/24/2013)
Timber Crest Apartments, LLC		
(Colonial Village at Timber Crest Apts.)	WR-412, SUB 7	(07/12/2013)
TPADRP, LLC		
(Sterling Town Center Apartments)	WR-1411, SUB 1	(12/16/2013)
Tradition at Mallard Creek, LLC; The		
(Tradition at Mallard Creek Apts.)	WR-353, SUB 3	(11/04/2013)
Tradition at Stonewater I, LP		
(The Tradition at Stonewater Apts.)	WR-931, SUB 3	(09/10/2013)
Treybrooke Village Apartments, LLC		
(Treybrooke Village Apartments)	WR-379, SUB 6	(01/22/2013)
Triangle Real Estate of Gastonia, Inc.		
(Eagle's Walk Apartments)	WR-1125, SUB 6	(09/30/2013)
(Huntersville Commons Apartments)	WR-1125, SUB 7	(09/30/2013)
(Pinetree Apartments)	WR-1125, SUB 8	(09/30/2013)

ORDER APPROVING TARIFF REVISION

Orders Issued *(Continued)*

Company	Docket No.	Date
Trinity Commons Apartments, LLC		
(Colonial Grand/Trinity Commons Apts.)	WR-415, SUB 7	(08/20/2013)
Triple Overlook, LLC		
(Triple Overlook Mobile Home Park)	WR-1047, SUB 3	(08/01/2013)
Tritex Real Estate Advisors, Inc.		
(Eastchase Apartments)	WR-1273, SUB 2	(05/28/2013)
(Hanover Landing Apartments)	WR-1273, SUB 3	(07/29/2013)
TS Creekstone, LLC		
(Woodfield Creekside Apartments)	WR-1461, SUB 1	(10/22/2013)
TS Westmont, LLC		
(Westmont Commons Apartments)	WR-1462, SUB 1	(08/20/2013)
Tucker Acquisition Corporation		
(712 Tucker Apartments)	WR-1039, SUB 4	(08/21/2013)
Twin Cedars Limited Partnership		
(Twin Cedars II Apartments)	WR-225, SUB 6	(02/18/2013)
VAC, LLLP		
(Eastwood Apartments)	WR-831, SUB 107	(07/30/2013)
(Chesterfield Apartments)	WR-831, SUB 108	(07/30/2013)
(Briarwood Apartments)	WR-831, SUB 109	(07/30/2013)
(Oakwood Apartments)	WR-831, SUB 110	(07/30/2013)
(Rosewood Apartments)	WR-831, SUB 111	(07/30/2013)
(Princeton Apartments)	WR-831, SUB 112	(07/30/2013)
Vanstory Apartments, LLC		
(Ashbrook Pointe Apartments)	WR-126, SUB 10	(07/16/2013)
Village at Carver Falls II, LLC; The		
(The Village at Carver Falls Apts.)	WR-563, SUB 4	(05/22/2013)
Village Rental Company, LLC		
(Villager Apartments)	WR-468, SUB 4	(09/16/2013)
Villas at Murrayville, LLC		
(Hawthorne at Murrayville Apts.)	WR-1221, SUB 1	(06/24/2013)
Wakefield Glen Apartments, LLC		
(Wakefield Glen Apartments)	WR-892, SUB 3	(08/28/2013)
Water Garden Village, LLC		
(Water Garden Village Apartments)	WR-1315, SUB 1	(09/12/2013)
Waterford Lakes Partners, LLC		
(Waterford Lakes Apartments)	WR-731, SUB 3	(10/03/2013)
Waterford Square Apartments Associates, LLC		
(Waterford Square Apartments)	WR-251, SUB 6	(10/14/2013)
Waverly Apartments, LLC		
(The Waverly Apartments)	WR-1293, SUB 1	(07/16/2013)

ORDERS AND DECISIONS LISTED

ORDER APPROVING TARIFF REVISION

Orders Issued (Continued)

Company	Docket No.	Date
Weirbridge Village Apartments, LLC		
(Weirbridge Village Apartments)	WR-1168, SUB 1	(01/22/2013)
(Weirbridge Village Apartments)	WR-1168, SUB 2	(11/12/2013)
West Market Partners, LLC		
(The Amesbury on West Market Apts.)	WR-749, SUB 5	(08/07/2013)
West Morgan, LLC		
(927 West Morgan Apartments)	WR-1428, SUB 1	(09/10/2013)
Westdale Arrowhead Crossing NC, LLC		
(Arrowhead Crossing Apartments)	WR-634, SUB 5	(02/25/2013)
(Arrowhead Crossing Apartments)	WR-634, SUB 6	(07/30/2013)
Westdale Beech Lake, LLC		
(Beech Lake Apartments)	WR-1213, SUB 2	(09/30/2013)
Westdale Brentmoor, LLC		
(Brentmoor Apartments)	WR-1317, SUB 1	(08/05/2013)
Westdale Chase on Monroe NC, LLC		
(Chase on Monroe Apartments)	WR-635, SUB 6	(08/02/2013)
Westdale Galleria Village, LLC		
(Galleria Apartment Homes)	WR-1224, SUB 2	(07/29/2013)
Westdale Lenox, LLC		
(Lenox at Patterson Place Apts.)	WR-1351, SUB 1	(12/18/2013)
Westdale NC Summit Creek, Ltd.		
(Johnston Creek Crossing Apartments)	WR-826, SUB 5	(07/30/2013)
Westdale Peppertree, Ltd.		
(Peppertree Apartments)	WR-815, SUB 5	(07/30/2013)
Westdale Sabal Point NC, LLC		
(Sabal Point Apartments)	WR-636, SUB 6	(07/30/2013)
Westdale Willow Glen NC, LLC		
(Willow Glen Apartments)	WR-633, SUB 6	(08/02/2013)
Westfield Thorngrove, LLC		
(Thorngrove Apartments)	WR-906, SUB 5	(09/20/2013)
Windsor Burlington, LLC		
(Windsor Upon Stonecrest Apartments)	WR-594, SUB 3	(08/20/2013)
Windsor Landing Investments I, LLC, et al.		
(Windsor Landing Apartments)	WR-886, SUB 3	(11/19/2013)
Winkler; Carl K.		
(Mulberry Hill Mobile Home Park)	WR-887, SUB 3	(09/04/2013)
Winslow Park, LLC		
(Wynslow Park Apartments)	WR-128, SUB 3	(12/02/2013)
Winstead Warehousing, LLC		
(Hawthorne Crossing Apartments)	WR-1222, SUB 1	(06/24/2013)
(Hawthorne Crossing Apartments)	WR-1222, SUB 2	(09/24/2013)

ORDER APPROVING TARIFF REVISION
Orders Issued (Continued)

Company	Docket No.	Date
WMCi Charlotte I, LLC		
(Bexley Commons at Rosedale Apts.)	WR-213, SUB 11	(07/15/2013)
WMCi Charlotte II, LLC		
(Bexley Creekside Apartments)	WR-230, SUB 10	(07/15/2013)
WMCi Charlotte III, LLC		
(Bexley at Lake Norman Apts.)	WR-258, SUB 10	(07/15/2013)
WMCi Charlotte IV, LLC		
(Bexley Crossing at Providence Apts.)	WR-269, SUB 10	(07/15/2013)
WMCi Charlotte V, LLC		
(Bexley at Springs Farm Apts.)	WR-340, SUB 9	(07/15/2013)
WMCi Charlotte VII, LLC		
(Bexley at Davidson Apartments)	WR-392, SUB 8	(07/15/2013)
WMCi Charlotte VIII, LLC		
(Bexley at Matthews Apartments)	WR-466, SUB 8	(07/15/2013)
WMCi Charlotte IX, LLC		
(Bexley Greenway Apartments)	WR-467, SUB 8	(07/15/2013)
WMCi Charlotte X, LLC		
(Bexley Harborside Apartments)	WR-638, SUB 6	(07/15/2013)
WMCi Charlotte XI, LLC		
(Bexley at Steelecroft Apartments)	WR-1117, SUB 3	(07/15/2013)
WMCi Charlotte XII, LLC		
(Bexley Cloisters at Steelecroft Apts.)	WR-1136, SUB 2	(07/15/2013)
WMCi Raleigh I, LLC		
(Bexley at Preston Apartments)	WR-327, SUB 8	(07/26/2013)
WMCi Raleigh II, LLC		
(Bexley Park Apartments)	WR-317, SUB 8	(07/26/2013)
WMCi Raleigh III, LLC		
(Bexley at Brier Creek Apartments)	WR-754, SUB 9	(07/22/2013)
WMCi Raleigh IV, LLC		
(Bexley at Heritage Apartments)	WR-803, SUB 3	(07/22/2013)
WMCi Raleigh V, LLC		
(Bexley at Carpenter Village Apartments)	WR-949, SUB 5	(07/26/2013)
WMCi Raleigh VI, LLC		
(Bexley at Triangle Park Apartments)	WR-1311, SUB 1	(07/25/2013)
WMCi Raleigh VIII, LLC		
(Bexley Panther Creek Apartments)	WR-1372, SUB 1	(07/25/2013)
Woodberry Asheville Apartments, LLC		
(Woodberry Apartments)	WR-791, SUB 4	(03/19/2013)

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ORDER APPROVING TARIFF REVISION
Orders Issued (Continued)

Company	Docket No.	Date
YES Companies EXP, LLC		
(Foxhall Village Manufactured HC)	WR-1336, SUB 7	(10/29/2013)
(Green Spring Valley MHC)	WR-1336, SUB 8	(10/29/2013)
(Stony Brook North MHC)	WR-1336, SUB 9	(10/29/2013)
(Village Park MHC)	WR-1336, SUB 10	(10/29/2013)
(Gallant Estates MHC)	WR-1336, SUB 11	(10/29/2013)
(Oakwood Forest MHC)	WR-1336, SUB 12	(10/29/2013)
(Woodlake MHC)	WR-1336, SUB 13	(10/29/2013)
Yopp Properties, LLC		
(West Meadows Apartments)	WR-1401, SUB 1	(12/09/2013)
Yorktowne Apartments, LLC		
(Yorktown Club Apartments)	WR-1128, SUB 2	(07/24/2013)
100 Spring Meadow Drive Apts. Investors, LLC		
(Alta Springs Apartments)	WR-47, SUB 9	(09/09/2013)
1052, LLC		
(Clairmont at Farmgate Apts.)	WR-957, SUB 3	(07/22/2013)
1300 Knoll Circle Apts. Investors, LLC		
(The Lodge at Southpoint Apartments)	WR-268, SUB 8	(07/29/2013)
1452, LLC		
(Clairmont at Hillandale Apartments)	WR-1118, SUB 2	(07/24/2013)
4209 Lassiter Mill Road Apts., Investors, LLC		
(Alexan North Hills Apartments)	WR-571, SUB 4	(09/10/2013)

Beckanna Partners, LLC – WR-1460, SUB 2; Order Disapproving Tariff Revision *(Beckanna on Glenwood Apartments)* (09/18/2013)

Chapman; Roy & Betty -- WR 1035, SUB 3; Errata Order *(Twin Willows Mobile Home Park)* (08/12/2013)

Crowne Club Associates, L. P. – WR-1031, SUB 2; Errata Order *(Crowne Club Apartments)* (03/19/2013)

CSFB 2007-C2 Summerlyn, LLC – WR-1302, SUB 1; Reissued Order Approving Tariff Revision *(Summerlyn Place Apartments)* (01/02/2013)

Fund IX PR Durham, LLC -- WR-518, SUB 8; Order Disapproving Tariff Revision *(Pinnacle Ridge Apartments)* (10/18/2013); Reissued Order Disapproving Tariff Revision (10/21/2013)

Mebane Apartments Associates – WR-485, SUB 5; Errata Order *(Ashbury Square Apartments)* (01/10/2013)

Mid-America Apartments, L.P. – WR-22, SUB 54; Order Disapproving Tariff Revision *(The Corners at Crystal Lake Apartments)* (10/17/2013)

ORDER APPROVING TARIFF REVISION (HWCCWA)
Orders Issued

Company	Docket No.	Date
Brentwood West Company, LLC		
(Brentwood West Apartments)	WR-1160, SUB 3	(09/11/2013)
Brook Dana, LLC		
(Brook Hill Apartments)	WR-1281, SUB 2	(07/29/2013)
CDC-Durham/UC, LLC		
(Duke Villa Apartments)	WR-1100, SUB 5	(09/16/2013)
(Duke Court Apartments)	WR-1100, SUB 6	(09/16/2013)
CSP Lexington Farms, LLC		
(Lexington Farms Apartments)	WR-1269, SUB 1	(11/12/2013)
EWT 22, LLC		
(The Willows Apartments)	WR-1329, SUB 1	(09/09/2013)
Heritage Lakes I, LLC, et al.		
(The Lakes Apartments)	WR-1202, SUB 1	(09/12/2013)
HR Realty Company, LLC		
(Hunting Ridge Apartments)	WR-1161, SUB 3	(09/11/2013)
Lake Clair, LLC		
(Lake Clair Apartments)	WR-1223, SUB 2	(10/08/2013)
Merriwood Associates Limited Partnership		
(Merriwood Apartments)	WR-1447, SUB 1	(10/03/2013)
Montecito Company, LLC		
(Montecito Apartments)	WR-1162, SUB 3	(09/11/2013)
MP Clarion Crossing, LLC		
(Clarion Crossing Apartments)	WR-1078, SUB 3	(09/16/2013)
New Cardinal Woods Associates, LLC		
(Cary Pines Apartments)	WR-1232, SUB 2	(07/29/2013)
New Honeytree Associates L. P.		
(Honeytree Apartments)	WR-1227, SUB 2	(07/24/2013)
New Woodcreek Associates, LLC		
(Woodcreek Apartments)	WR-1233, SUB 2	(07/29/2013)
PC Oxford, LLC		
(Oxford Square Apartments)	WR-1383, SUB 1	(07/25/2013)
Polo Court Apartments, LLC		
(Colonial Village Apartments)	WR-1520, SUB 1	(12/16/2013)
PRG Lake Johnson Mews Associates, LLC		
(Lake Johnson Mews Apartments)	WR-1234, SUB 2	(07/24/2013)
QR Realty Company, LLC		
(Quail Ridge Apartments)	WR-1159, SUB 3	(09/11/2013)
Schmitz; Robert L.		
(1212 Chapel Hill Street Apartments)	WR-1249, SUB 3	(07/09/2013)

ORDER APPROVING TARIFF REVISION (HWCCWA)
Orders Issued (Continued)

Company	Docket No.	Date
Shellbrook Associates, LP		
(Shellbrook Apartments)	WR-1192, SUB 3	(09/11/2013)
Silverstone Apartment Homes, LLC		
(Silverstone Apartments)	WR-1355, SUB 1	(08/21/2013)
Sumare Limited Partnership		
(Sumter Square Apartments)	WR-1163, SUB 4	(09/11/2013)
TBR Lake Boone Owner, LLC		
(The Villages of Lake Boone Trail Apts.)	WR-1374, SUB 1	(08/01/2013)
Treetop Associates Limited Partnership		
(Tree Top Apartments)	WR-1231, SUB 2	(07/24/2013)
West Montecito Company, Limited Partnership		
(Montecito West Apartments)	WR-1164, SUB 3	(09/11/2013)

RESALE OF WATER AND SEWER -- Sale/Transfer

ORDER GRANTING TRANSFER OF CERTIFICATE OF AUTHORITY AND APPROVING RATES
Orders Issued

Company	Docket No.	Date
AERC Blakeney, LP		
(The Apartments at Blakeney)	WR-1547, SUB 0 WR-1201, SUB 3	(12/30/2013)
Bell Fund IV Morrisville Apts., LLC		
(Bell Preston View Apartments)	WR-1391, SUB 0 WR-988, SUB 3	(03/12/2013)
Bell Fund V Wakefield, LLC		
(Bell Wakefield Apartments)	WR-1540, SUB 0 WR-372, SUB 3	(12/10/2013)
BH-East of North, LLC		
(Timber Hollow Apartments)	WR-1382, SUB 0 WR-1062, SUB 2	(02/26/2013)
BHC-Hawthorne Cambridge, LLC		
(Hawthorne at Commonwealth Apts.)	WR-1381, SUB 0 WR-669, SUB 3	(02/26/2013)
CCC Windsor Falls, LLC		
(Windsor Falls Apartments)	WR-1373, SUB 0 WR-628, SUB 4	(02/04/2013)

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ORDER GRANTING TRANSFER OF CERTIFICATE OF AUTHORITY AND APPROVING RATES

Orders Issued *(Continued)*

Company	Docket No.	Date
Centennial Addington Farms, LLC		
(Century Trinity Estates Apts.)	WR-1403, SUB 0 WR-575, SUB 8	(04/08/2013)
CMLT 2008-LS1 Guilford Living, LLC		
(Ashley Oaks Apartments)	WR-1407, SUB 0 WR-1147, SUB 2	(04/16/2013)
CMLT 2008-LS1 Hewitt Street, LLC		
(Aspen Woods Apartments)	WR-1408, SUB 0 WR-1143, SUB 2	(04/16/2013)
CMLT 2008-LS1 Living 4203, LLC		
(Misty Creek Apartments)	WR-1405, SUB 0 WR-1146, SUB 2	(04/16/2013)
CMLT 2008-LS1 Living 4351, LLC		
(Wendover West Apartments)	WR-1406, SUB 0 WR-1144, SUB 2	(04/16/2013)
Colonial Alabama Limited Partnership		
(Colonial Grand at Research Park Apts.)	WR-437, SUB 32 WR-411, SUB 7	(01/07/2013)
Deancurt Raleigh, LLC		
(Manor Six Forks Apartments)	WR-1493, SUB 0 WR-1042, SUB 1	(09/16/2013)
DPR Southpoint Crossing, LLC		
(Southpoint Crossing Apartments)	WR-1385, SUB 0 WR-185, SUB 9	(03/06/2013)
Fairfield Berkeley Place, LLC		
(Berkeley Place Apartments)	WR-1458, SUB 0 WR-581, SUB 4	(07/08/2013)
Fairfield Chapel Hill, LLC		
(Bridges at Chapel Hill Apartments)	WR-1421, SUB 0 WR-607, SUB 8	(04/24/2013)
Fairfield Chason Ridge, LLC		
(Chason Ridge Apartments)	WR-1414, SUB 0 WR-64, SUB 11	(04/22/2013)

ORDERS AND DECISIONS LISTED

ORDER GRANTING TRANSFER OF CERTIFICATE OF AUTHORITY AND APPROVING RATES

Orders Issued *(Continued)*

Company	Docket No.	Date
Fairfield Fairington, LLC		
(The Fairington Apartments)	WR-1418, SUB 0 WR-952, SUB 4	(04/23/2013)
Fairfield Hamptons, LLC		
(The Hamptons at Southpark Apartments)	WR-1422, SUB 0 WR-606, SUB 7	(04/24/2013)
Fairfield Mallard I, LLC		
(Bridges at Mallard Creek Apts., Ph. I)	WR-1425, SUB 0 WR-393, SUB 8	(04/25/2013)
Fairfield Mallard II, LLC		
(Bridges at Mallard Creek Apts., Ph. II)	WR-1415, SUB 0 WR-609, SUB 7	(04/22/2013)
Fairfield Marina Shores, LLC		
(Marina Shores Waterfront Apts.)	WR-1420, SUB 0 WR-605, SUB 7	(04/24/2013)
Fairfield Oakbrook, LLC		
(Oakbrook Apartments)	WR-1423, SUB 0 WR-613, SUB 7	(04/24/2013)
Fairfield Paces Commons, LLC		
(Paces Commons Apartments)	WR-1427, SUB 0 WR-604, SUB 7	(04/25/2013)
Fairfield Quail Hollow, LLC		
(Bridges at Quail Hollow Apartments)	WR-1413, SUB 0 WR-615, SUB 7	(04/22/2013)
Fairfield Southpoint, LLC		
(Bridges at Southpoint Apartments)	WR-1419, SUB 0 WR-333, SUB 10	(04/23/2013)
Fairfield Waterford, LLC		
(Waterford Place Apartments)	WR-1424, SUB 0 WR-444, SUB 8	(04/25/2013)
Fairfield Wind River, LLC		
(Bridges at Wind River Apartments)	WR-1412, SUB 0 WR-611, SUB 7	(04/22/2013)

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ORDER GRANTING TRANSFER OF CERTIFICATE OF AUTHORITY AND APPROVING RATES

Orders Issued (Continued)

Company	Docket No.	Date
Forest at Chasewood, LLC; The		
(The Forest at Chasewood Apts.)	WR-1504, SUB 0 WR-1273, SUB 4	(10/08/2013)
Forest MMXII, LLC		
(Copper Creek Apartments)	WR-1367, SUB 0 WR-42, SUB 70	(01/09/2013)
Golden Triangle #3, LLC		
(Carmel on Providence Apartments)	WR-1439, SUB 0 WR-927, SUB 4	(05/21/2013)
Hawthorne-Midway Meridian, LLC		
(Hawthorne at the Trail Apartments)	WR-1386, SUB 0 WR-651, SUB 1	(03/25/2013)
Holiday City MHC, LLC		
(Holiday City Mobile Home Park)	WR-1454, SUB 0 WR-1169, SUB 1	(07/01/2013)
KBS Legacy Partners Wesley, LLC		
(Wesley Village Apartments)	WR-1379, SUB 0 WR-993, SUB 1	(02/19/2013)
Lambeth MHC, LLC		
(Lambeth Mobile Home Park)	WR-1364, SUB 0 WR-1115, SUB 1	(01/28/2013)
Landmark at Brighton Colony, LLC		
(Landmark at Brighton Colony Apts.)	WR-1488, SUB 0 WR-781, SUB 4	(09/05/2013)
Landmark at Greenbrooke Commons, LLC		
(Landmark at Greenbrooke Commons Apartments)	WR-1489, SUB 0 WR-453, SUB 5 WR-621, SUB 4	(09/05/2013)
Landmark at Lynden Square, LP		
(Landmark at Lynden Square Apts.)	WR-1483, SUB 0 WR-975, SUB 32	(08/21/2013)
LAT Mallard Creek, LLC		
(Landmark at Mallard Creek Apts.)	WR-1490, SUB 0 WR-364, SUB 4	(09/05/2013)

ORDER GRANTING TRANSFER OF CERTIFICATE OF AUTHORITY AND APPROVING RATES

Orders Issued (Continued)

Company	Docket No.	Date
LAT University Place, LLC		
(Landmark at Monaco Gardens Apts.)	WR-1491, SUB 0 WR-363, SUB 4	(09/05/2013)
MP Artisan Brightleaf Apartments, LLC		
(Artisan at Brightleaf Apts.)	WR-1478, SUB 0 WR-1321, SUB 1	(08/13/2013)
NIC Meadowmont, LLC		
(Bell Meadowmont Apartments)	WR-1539, SUB 0 WR-1014, SUB 3	(12/10/2013)
North Forsyth MHC, LLC		
(North Forsyth Mobile HP)	WR-1469, SUB 0 WR-1357, SUB 1	(07/22/2013)
Park Commons MMXII, LLC		
(Parkland Commons Apartments)	WR-1366, SUB 0 WR-42, SUB 69	(01/09/2013)
Parkwood MHC, LLC		
(Parkwood Mobile Home Park)	WR-1365, SUB 0 WR-1114, SUB 1	(01/28/2013)
Passco Encore at the Park DST		
(Encore at the Park Apartments)	WR-1498, SUB 0 WR-989, SUB 4	(09/24/2013)
Passco Rivergate DST		
(Enclave at Rivergate Apartments)	WR-1433, SUB 0 WR-982, SUB 1	(05/13/2013)
PG McAlpine Creek Apartments, LLC		
(Retreat at McAlpine Creek Apts.)	WR-1537, SUB 0 WR-561, SUB 5	(12/09/2013)
Pine Knoll Mobile Home Park, LLC		
(Pine Knoll Mobile Home Park)	WR-1434, SUB 0 WR-471, SUB 2	(05/14/2013)
SBC 2013-1 REO 105832, LLC		
(Hanover Landing Apartments)	WR-1531, SUB 0 WR-1273, SUB 5	(11/25/2013)
Serenity Apartments at Greensboro, LLC		
(Serenity Apartments)	WR-1502, SUB 0 WR-1345, SUB 1	(10/08/2013)
Terrace Mews, LLC		
(Terrace Mews Apartments)	WR-1394, SUB 0 WR-569, SUB 2	(03/13/2013)

ORDERS AND DECISIONS LISTED

ORDER GRANTING TRANSFER OF CERTIFICATE OF AUTHORITY AND APPROVING RATES

Orders Issued (Continued)

Company	Docket No.	Date
TGM Rock Creek		
(Rock Creek Apartments)	WR-1393, SUB 0 WR-992, SUB 4	(03/13/2013)
TS Creekstone, LLC		
(Woodfield Creekside Apts.)	WR-1461, SUB 0 WR-1319, SUB 1	(07/09/2013)
WMCi Charlotte XV, LLC		
(Cielo Apartments)	WR-1486, SUB 0 WR-1095, SUB 1	(08/28/2013)
WMCi Raleigh VII, LLC		
(Bexley Panther Creek Apartments)	WR-1372, SUB 0 WR-820, SUB 5	(01/28/2013)

BH-East of North, LLC – WR-1382, SUB 0; WR-1062, SUB 2; Reissued Order Granting Transfer of HWCCWA Certificate of Authority and Approving Rates *(Timber Hollow Apartments)* (08/09/2013)

Colonial Alabama Limited Partnership – WR-437, SUB 32; WR-411, SUB 7; Errata Order *(Colonial Grand at Research Park Apartments)* (01/08/2013)

Fairfield Oak Hollow, LLC – WR-1426, SUB 0; WR-1009, SUB 5; Order Granting Transfer of HWCCWA Certificate of Authority and Approving Rates *(Oak Hollow Apartments)* (04/25/2013)

Fairfield Woods Edge, LLC – WR-1417, SUB 0; WR-1010, SUB 4; Order Granting Transfer of HWCCWA Certificate of Authority and Approving Rates *(Woods Edge Apartments)* (04/23/2013)

Honeytree Acquisition – WR-1545, SUB 0; WR-1227, SUB 3; Order Granting Transfer of HWCCWA Certificate of Authority and Approving Rates *(Honeytree Apartments)* (12/19/2013)

Serenity Apartments at Greensboro, LLC – WR-1502, SUB 0; WR-1345, SUB 1; Errata Order *(Serenity Apartments)* (10/11/2013)

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