ONE-HUNDRED FIRST REPORT

OF THE

NORTH CAROLINA

UTILITIES COMMISSION

ORDERS AND DECISIONS

ISSUED FROM
JANUARY 1, 2011 THROUGH DECEMBER 31, 2011

ONE-HUNDRED FIRST REPORT
of the
NORTH CAROLINA UTILITIES COMMISSION

ORDERS AND DECISIONS

Issued from

January 1, 2011, through December 31, 2011

Edward S. Finley, Jr., Chairman

Lorinzo L. Joyner, Commissioner

William T. Culpepper, III, Commissioner

Bryan E. Beatty, Commissioner

Susan W. Rabon, Commissioner

ToNola D. Brown-Bland, Commissioner

Lucy T. Allen, Commissioner

North Carolina Utilities Commission
Office of the Chief Clerk
Ms. Renné Vance
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.

LETTER OF TRANSMITTAL

December 31, 2011

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, 2011, we hereby present for your consideration the report of the Commission's significant decisions for the 12-month period beginning January 1, 2011, and ending December 31, 2011.

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

Lorinzo L. Joyner, Commissioner

William T. Culpepper, III, Commissioner

Bryan E. Beatty, Commissioner

Susan W. Rabon, Commissioner

ToNola D. Brown-Bland, Commissioner

Lucy T. Allen, Commissioner

Renné Vance, Chief Clerk

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DOCKET NO. E-100, SUB 127

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2010	)))	ORDER ESTABLISHING STANDARD RATES AND CONTRACT TERMS FOR QUALIFYING FACILITIES

HEARD: Tuesday, January 25, 2011, at 9:00 a.m. in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina 27603

BEFORE: Commissioner William T. Culpepper, III, Presiding, Chairman Edward S. Finley, Jr., and Commissioners Lorinzo L. Joyner, Bryan E. Beatty, Susan W. Rabon, 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., 3700 Glenwood Avenue, Suite 330, Raleigh, North Carolina 27612

Kendrick Fentress, Associate General Counsel, Duke Energy Corporation, 3700 Glenwood Avenue, Suite 300, Raleigh, North Carolina 27612

For Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc.:

Len S. Anthony, General Counsel, Post Office Box 1551, PEB 17A4, Raleigh, North Carolina 27602

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

Robert W. Kaylor, Law Office of Robert W. Kaylor, P.A., 3700 Glenwood Avenue, Suite 330, Raleigh, North Carolina 27612

For the Using and Consuming Public:

Gisele L. Rankin, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: These are the current biennial proceedings held by the North Carolina Utilities Commission pursuant to the provisions of Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA) and the Federal Energy Regulatory Commission (FERC) regulations implementing those provisions, which delegated responsibilities in that regard to this Commission. These proceedings also are held pursuant to the responsibilities delegated to this Commission under G.S. 62-156(b) to establish rates for small power producers as that term is defined in G.S. 62-3(27a).

Section 210 of PURPA and the regulations promulgated pursuant thereto by the FERC prescribe the responsibilities of the FERC and of state regulatory authorities, such as this Commission, relating to the development of cogeneration and small power production. Section 210 of PURPA requires the FERC to prescribe such rules as it determines necessary to encourage cogeneration and small power production, including rules requiring electric utilities to purchase electric power from, and to sell electric power to, cogeneration and small power production facilities. Under Section 210 of PURPA, cogeneration facilities and small power production facilities that meet certain standards and are not owned by persons primarily engaged in the generation or sale of electric power can become qualifying facilities (QFs), and thus become eligible for the rates and exemptions established in accordance with Section 210 of PURPA.

Each electric utility is required under Section 210 of PURPA to offer to purchase available electric energy from cogeneration and small power production facilities that obtain qualifying facility status under Section 210 of PURPA. For such purchases, electric utilities are required to pay rates which are just and reasonable to the ratepayers of the utility, are in the public interest, and do not discriminate against cogenerators or small power producers. The FERC regulations require that the rates electric utilities pay to purchase electric energy and capacity from qualifying cogenerators and small power producers reflect the cost that the purchasing utility can avoid as a result of obtaining energy and capacity from these sources, rather than generating an equivalent amount of energy itself or purchasing the energy or capacity from other suppliers.

With respect to electric utilities subject to state jurisdiction, the FERC delegated the implementation of these rules to the state regulatory authorities. State commissions may implement these rules by the issuance of regulations, on a case-by-case basis, or by any other means reasonably designed to give effect to the FERC's rules.

The Commission determined to implement Section 210 of PURPA and the related FERC regulations by holding biennial proceedings. The instant proceeding is the latest such proceeding to be held by this Commission since the enactment of PURPA. In prior biennial proceedings, the Commission has determined separate avoided cost rates to be paid by electric utilities to the QFs with which they interconnect. The Commission also has reviewed and approved other related matters involving the relationship between the electric utilities and such QFs, such as terms and conditions of service, contractual arrangements and interconnection charges.

This proceeding also is a result of the mandate of G.S. 62-156, which was enacted by the General Assembly in 1979. This statute provides that "no later than March 1, 1981, and at least every two years thereafter" the Commission shall determine the rates to be paid by electric utilities for power purchased from small power producers according to certain standards prescribed therein. Such standards generally approximate those prescribed in the FERC regulations regarding factors to be considered in the determination of avoided cost rates. The definition of the term "small power producer" for purposes of G.S. 62-156 is more restrictive than the PURPA definition of that term, in that G.S. 62-3(27a) includes only hydroelectric facilities of 80 MW or less, thus excluding users of other types of renewable resources.

On May 5, 2010, the Commission issued its Order Establishing Biennial Proceeding, Requiring Data and Scheduling Public Hearing. That Order made Carolina Power and Light Company, d/b/a Progress Energy Carolinas, Inc. (PEC); Duke Energy Carolinas, LLC (Duke); Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (NC Power); and Western Carolina University (WCU) parties to the proceeding in order to establish the avoided cost rates each is to pay for power purchased from QFs pursuant to the provisions of Section 210 of PURPA and the associated FERC regulations and G.S. 62-156. The Order also required each electric utility to file proposed rates and proposed standard form contracts.

This procedural order also stated that the Commission would attempt to resolve all issues arising in the docket based on a record developed through public witness testimony, written statements, exhibits and avoided cost schedules verified by persons who would otherwise be qualified to present expert testimony in a formal hearing, and written comments on the statements, exhibits and schedules, rather than a full evidentiary hearing. PEC, Duke, NC Power, and WCU were required to file their statements and exhibits by November 1, 2010. Other persons desiring to become parties were allowed to intervene and file their comments and exhibits by January 10, 2011. All parties were allowed to file reply comments and proposed orders. The deadlines for comments, reply comments, and proposed orders were subsequently extended to February 22, March 30, and April 27, 2011, respectively. The Commission scheduled a public hearing for January 25, 2011, solely for the purpose of taking non-expert public witness testimony. Finally, the Commission required PEC, Duke, NC Power, and WCU to publish notice and submit Affidavits of Publication no later than the date of the hearing.

WCU filed its comments and proposed rates on October 21, 2010. PEC, Duke and NC Power filed their initial statements and exhibits on November 1, 2010. Duke filed a revised initial statement on November 29, 2010. NC Power also filed a comparison of avoided cost payments on July 15, 2010, and January 12, 2011.

In addition to the Public Staff-North Carolina Utilities Commission (Public Staff), the following parties filed timely petitions to intervene that were granted: the Public Works Commission of Fayetteville (Fayetteville), the North Carolina Sustainable Energy Association (NCSEA), the Carolina Industrial Group for Fair Utility Rates I, II, and III (CIGFUR), Carolina Utility Customers Association, Inc. (CUCA), and Charles B. Mierek.

The hearing scheduled for January 25, 2011, for the purpose of taking non-expert public witness testimony was held as scheduled. No witnesses appeared at this hearing.

On March 1, 2011, pursuant to a further extension of time, the Public Staff filed its initial statement. On March 2, 2011, New River Light and Power Company (New River) filed its comments and avoided cost rates. On March 16, 2011, WCU filed a clarification of its exhibits. Pursuant to a further extension of time, PEC, Duke, and NC Power filed reply comments on April 4, 2011. On April 20, 2011, New River submitted a revised avoided cost filing. Proposed orders were filed by NC Power, PEC, Duke, and the Public Staff on April 29, 2011.

GENERAL ORDERS – ELECTRIC

Various filings were made and orders issued which are not discussed in this order but are included in the record of this proceeding.

Based on the entire record in this proceeding, the Commission now makes the following

FINDINGS OF FACT

1. PEC should be required to offer long-term levelized capacity payments and energy payments for five-year, ten-year and 15-year periods as standard options to (a) hydroelectric qualifying facilities owned or operated by small power producers as defined in G.S. 62-3(27a) contracting to sell five megawatts (MW) or less capacity and (b) non-hydroelectric qualifying facilities fueled by trash or methane derived from landfills, hog waste, poultry waste, solar, wind, and non-animal forms of biomass contracting to sell 5 MW or less capacity. The standard levelized rate options of ten and 15 years should include a condition making contracts under those options renewable for subsequent terms at the option of the utility on substantially the same terms and provisions and at a rate either (1) mutually agreed upon by the parties negotiating in good faith and taking into consideration the utility's then avoided cost rates and other relevant factors or (2) set by arbitration. PEC should offer its standard five-year levelized rate option to all other qualifying facilities contracting to sell 3 MW or less capacity.

2. Duke should be required to offer long-term levelized capacity payments and energy payments for five-year, ten-year and 15-year periods as standard options to (a) hydroelectric qualifying facilities owned or operated by small power producers as defined in G.S. 62-3(27a) contracting to sell 5 MW or less capacity and (b) non-hydroelectric qualifying facilities fueled by trash or methane derived from landfills, hog waste, poultry waste, solar, wind, and non-animal forms of biomass contracting to sell 5 MW or less capacity. The standard levelized rate options of ten and 15 years should include a condition making contracts under those options renewable for subsequent terms at the option of the utility on substantially the same terms and provisions and at a rate either (1) mutually agreed upon by the parties negotiating in good faith and taking into consideration the utility's then avoided cost rates and other relevant factors or (2) set by arbitration. Duke should offer its standard five-year levelized rate option to all other qualifying facilities contracting to sell 3 MW or less capacity.

3. NC Power should be required to offer long-term levelized capacity payments and energy payments calculated pursuant to the differential revenue requirement (DRR) method based on long-term levelized generation mixes with adjustable fuel prices for five-year, ten-year and 15-year periods as standard options to (a) hydroelectric qualifying facilities owned or operated by small power producers as defined in G.S. 62-3(27a) contracting to sell 5 MW or less capacity and (b) non-hydroelectric qualifying facilities fueled by trash or methane derived from landfills, hog waste, poultry waste, solar, wind, and non-animal forms of biomass contracting to sell 5 MW or less capacity. The standard levelized rate options of ten and 15 years should include a condition making contracts under those options renewable for subsequent terms at the option of the utility on substantially the same terms and provisions and at a rate either (1) mutually agreed upon by the parties negotiating in good faith and taking into consideration the utility's then avoided cost rates and other relevant factors or (2) set by arbitration. The standard five-year levelized rate option should be offered to all other qualifying facilities

contracting to sell 3 MW or less capacity. Long-term levelized energy payments should be offered as an additional option for small qualifying facilities rated at 100 kW or less capacity.

4. NC Power should be required to file in the next avoided cost proceeding proposed fixed long-term, levelized avoided energy rates for five-year, ten-year and 15-year periods for QFs entitled to standard contracts.

5. It is appropriate for NC Power to offer, as an alternative to avoided cost rates derived using the DRR method, avoided cost rates based upon market clearing prices derived from the markets operated by PJM Interconnection, LLC (PJM), subject to the same conditions as approved in the 2006 biennial avoided cost proceeding (Docket No. E-100, Sub 106).

6. PEC, Duke, and NC Power should offer QFs not eligible for the standard long-term levelized rates the following three options if the utility has a Commission-recognized active solicitation underway: (1) participating in the utility's competitive bidding process, (2) negotiating a contract and rates with the utility, or (3) selling energy at the utility's Commission-established variable energy rate. If the utility does not have a Commission-recognized active solicitation underway, it should offer QFs not eligible for the standard long-term levelized rates the option of (1) contracting with the utility to sell power at the variable energy rate established by the Commission in these biennial proceedings or (2) contracting with the utility to sell power at negotiated rates. If the utility does not have a solicitation underway, any unresolved issues arising during such negotiations will be subject to arbitration by the Commission at the request of either the utility or the QF for the purpose of determining the utility's actual avoided cost, including both capacity and energy components, as appropriate; however, the Commission will conduct such an arbitration only if the QF is prepared to commit its capacity to the utility for a period of at least two years. In either case, whether there is an active solicitation underway or not, QFs not eligible for standard long-term levelized rates have the option of selling into the wholesale market. The exact points at which an active solicitation should be regarded as beginning and ending for these purposes should be determined by motion to, and order of, the Commission. Unless there is such a Commission order, it will be assumed that there is no solicitation underway. If the variable energy rate option is chosen, such rate may not be locked in by a contract term, but shall instead change as determined by the Commission in the next biennial proceeding.

7. Both the peaker method and the DRR method are generally accepted and used throughout the electric utility industry and are reasonable for use in this proceeding.

8. A performance adjustment factor (PAF) of 2.0 should be utilized by PEC and Duke in their respective avoided cost calculations for hydroelectric facilities with no storage capability and no other type of generation. PEC and Duke should use a PAF of 1.2 for all other QFs.

9. PEC's avoided energy costs should be calculated using the PROSYM Total System Cost output data, which includes start costs.

10. The contract clauses currently in place by Duke and NC Power that limit the availability of standard long-term contract rates in the time period immediately prior to the approval of new biennial rates are reasonable and should continue to be allowed.

11. PEC's proposed incorporation into the current framework of a viability prerequisite for QFs eligible for standard contracts should be rejected.

12. NC Power's inclusion of a regulatory disallowance clause in its standard contract for purchases of energy and capacity pursuant to Schedule 19-DRR is reasonable and should continue to be allowed.

13. The rate schedules and standard contract terms and conditions proposed in this proceeding by PEC, Duke, and NC Power should be approved except as otherwise discussed herein. The utilities should be required to file new versions of their rate schedules and standard contracts, in compliance with this Order, within 20 days after the date of this Order. Those rate schedules and standard contracts should be allowed to go into effect ten days after they have been filed unless specific objections as to the accuracy of the calculations and conformity to the decisions herein are filed within that ten-day period.

14. The avoided cost rates for WCU and New River, as filed, should be approved on an interim basis pending further order of the Commission.

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

No party to this proceeding proposed to change the availability of long-term levelized rate options for the specified QFs contracting to sell 5 MW or less capacity or the availability of five-year levelized rate options to all other qualifying facilities contracting to sell 3 MW or less capacity. The Commission has consistently concluded in prior avoided cost proceedings that it must reconsider the availability of long-term levelized rate options as economic circumstances change from one biennial proceeding to the next and that, in doing so, it must balance the need to encourage QF development, on the one hand, and the risks of overpayments and stranded costs on the other. The Commission continues to believe that its decisions in the most recent past avoided cost proceedings strike an appropriate balance between these concerns. The Commission, therefore, concludes that PEC and Duke should each continue to offer long-term levelized rate options of five-, ten- and 15-year terms to hydro QFs contracting to sell 5 MW or less and to QFs contracting to sell 5 MW or less that are fueled by trash or methane from landfills, hog waste, poultry waste, solar, wind, and non-animal forms of biomass, and that they should offer their five-year levelized rate options to all other qualifying facilities contracting to sell 3 MW or less capacity. With these limitations, long-term contract options serve important statewide policy interests while reducing the utilities' exposure to overpayments and should continue to be made available.

DISCUSSION AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3-5

In its filing, NC Power maintained that its proposed locational marginal pricing methodology offered several benefits, including the fact that it is transparent to all parties, it would enable QFs to make prudent decisions regarding the running of their facilities to maximize their revenues, and it more accurately reflects true avoided costs. Under this proposal, QFs would be paid for delivered energy and capacity the equivalent of what NC Power would have paid PJM if the QF generator had not been generating. The avoided energy rates to be paid to larger QFs with a design capacity of greater than 10 kW would be the PJM Dominion Zone Day-Ahead hourly locational marginal prices (LMPs) divided by ten, and multiplied by the QF's hourly generation, while smaller QFs that elect to supply energy would only be paid the average of the PJM Dominion Zone Day-Ahead hourly LMPs for the month as shown on the PJM website.

Capacity credits for Schedule 19-LMP would be paid on a cents per kWh rate for the 16 on-peak daily hours (7 a.m. to 11 p.m.) for all days. NC Power used the PJM Reliability Pricing Model (RPM) to determine its avoided capacity costs, which are the prices per MW per day from PJM's Base Residual Auction for the Dom Zone. As proposed in the last proceeding, NC Power adjusted the avoided capacity rate using a Summer Peak Performance Factor (SPPF) as an incentive for QFs to operate during PJM system peak days. The calculation of the SPPF incorporated historical operational data on five individual days during the prior year's summer peak season (defined by PJM as the period June 1 through September 30). The SPPF will vary depending upon the QF's prior year's operations.

NC Power also filed avoided energy costs using the DRR method, which is a more traditional method used to determine avoided costs. NC Power's avoided energy rates were determined using PROMOD, a production simulation model developed by Ventyx Energy, LLC, to estimate its marginal avoided fuel costs for on-peak and off-peak periods over the next 15 years. NC Power incorporated a "base" case and "with" QF capacity case with the resulting output used to determine the avoided energy rates and energy mixes. The Public Staff, in its initial statement, stated that, based upon its review, it believes the inputs into the model and the output data from the model are reasonable for the determination of NC Power's avoided energy costs.

For capacity, NC Power's Schedule 19-DRR included a payment for capacity that incorporated the PJM RPM as a proxy for avoided capacity costs for 2011 through 2013. NC Power then used forecasted capacity prices from ICF International, Inc., for 2014 through 2026. The Public Staff stated in its initial statement that it performed a comparison of these forward prices to the costs of a CT projected by Duke and PEC. While the influence of the RPM significantly lowers the five-year capacity rate, the ten-year and 15-year rates are comparable to the rates proposed by Duke and PEC that reflect the installed cost of a CT. In conclusion, the Public Staff stated that it did not object to the proposed forward capacity costs being used to determine the avoided capacity rates for NC Power in this proceeding, but that it intended to review the use of the RPM prices as a proxy in future proceedings.

In its initial statement, the Public Staff raised the issue as to whether NC Power's standard rate options are sufficiently fixed to comply with the FERC's recent interpretation of PURPA in J.D. Wind 1, LLC, 130 FERC ¶ 61,127 (2010), denying reh'g, 129 FERC ¶ 61,148 (2009) (J.D. Wind). In J.D. Wind, the FERC stated that its intention in its Order No. 69 was to enable a QF "to establish a fixed contract price for its energy and capacity at the outset of its obligation." J.D. Wind, ¶ 23 (quoting FERC Order No. 69, FERC Stats. & Regs. ¶ 30,128, at 30,880). The FERC went on to say that it has "consistently affirmed the right of QFs to long-term avoided cost contracts or other legally enforceable obligations with rates determined at the time the obligation is incurred, even if the avoided costs at the time of delivery ultimately differ from those calculated at the time the obligation is originally incurred." J.D. Wind, ¶ 23.

The Public Staff further stated that standard rate options for NC Power historically have included changes based upon long-term levelized generation mixes with adjustable fuel prices for QFs larger than 100 kW that are otherwise eligible for the standard rate options. Thus, only the first two years of a 15-year standard contract are fixed and stated in the tariff. See NC Power's filing of November 1, 2010, Schedule 19-DRR, Section VI(B). Given J.D. Wind and this Commission's interpretation of the FERC's orders, the Public Staff argued that this is not consistent with PURPA.

In its proposed order, NC Power explained that, under the Company's proposed Schedule 19-DRR, energy rates for QFs above 100 kW are fixed in two year increments over the life of NC Power's standard Purchase Power Agreement for the Sale of Electrical Output (PPA) through one of two methods. A QF may elect to (1) receive the energy payment approved by the Commission in each biennial proceeding, or (2) receive energy payments based on long-term levelized generation mixes with adjustable fuel prices.

NC Power noted that this biennial reset method for energy payments is not a recent development. The method was first approved by the Commission on an experimental basis in the 1989 avoided cost proceeding in Docket No. E-100, Sub 57. The Commission granted permanent approval to the existing Schedule 19-DRR energy rate method in the 1991 avoided cost proceeding in Docket No. E-100, Sub 59.

NC Power acknowledged that, in adopting its PURPA regulations, FERC recognized that "in order to be able to evaluate the financial feasibility of a [QF], an investor needs to be able to estimate, with reasonable certainty, the expected return on a potential investment before construction of a facility." J.D. Wind, ¶ 23 (quoting FERC Order No. 69, FERC Stats. & Regs. ¶ 30,128, at 30,868). NC Power argued that its Schedule 19-DRR energy pricing mechanism achieves this objective while at the same time protecting the interests of ratepayers.

NC Power contended that its energy mix approach reflects the different purposes of the capacity and energy rates in a typical project financed QF PPA. The capacity rate, which was and continues to be fixed over the term of the contract, is intended to cover the financing cost associated with a facility, while the energy rate is intended to recover the cost of fuel and O&M, which can vary over time. The Company's energy mix approach to energy rates under Schedule 19-DRR allows energy rates to reset according to fluctuations in commodity and O&M costs, which benefits both QFs and ratepayers. NC Power submitted that its existing energy payment mechanism, coupled with the fixed capacity payment, has and most likely will continue to provide investors with the reasonable certainty required for financing small QFs.

In addition, NC Power argued that its method protects both the QF and ratepayers from the ill effects resulting from the inherent likelihood of error in fixed energy prices based on long-term forecasts of generation mixes and fuel prices. According to the Company, predicting long-term fixed energy rates with accuracy is extremely difficult because of such factors as (1) the potential for new and more restrictive environmental regulations such as carbon legislation, (2) the increased emphasis on renewable energy at premium prices, (3) renewed interest in energy conservation and demand response programs, (4) volatile commodity market prices, and

(5) the correlations between fuels. Moreover, because estimates of avoided energy costs are dependent on a number of long-term assumptions that may not play out as anticipated, the risk of forecast error escalates as the forecast period lengthens. Under NC Power's methodology, the ratepayer or QF, as applicable, will bear the financial burden of inaccurate energy forecasts for only a relatively brief two-year period.

NC Power asserted that a formula rate is appropriate as a fixed price rate for QF avoided cost obligations. NC Power submitted that the energy price determination mechanism exemplified by Section VI of its Schedule 19-DRR is such a fixed formula rate.

Finally, NC Power argued that, should the Commission decide that fixed energy rates are required by PURPA, the Commission should not implement that decision in this proceeding. In support of this position, the Company noted that, when it prepared filings in this proceeding, it did so with the expectation that the Commission would continue its long-standing practice of allowing biennial reset of avoided energy rates. Consequently, NC Power did not prepare any long-term energy rate estimates other than rates for projects rated at 100 kW or less. Further, NC Power has not made any determination whether the DRR method would be the appropriate method to calculate long-term fixed avoided cost energy rates for QFs larger than 100 kW. Because of the risk to ratepayers and QFs discussed above, NC Power asserted that these are not decisions that should be made in haste. Moreover, NC Power argued that there is no evidence that its current method of calculating avoided energy costs has discouraged QF development in North Carolina. Accordingly, if the Commission should decide that fixed energy rates are required by PURPA, NC Power urged the Commission to implement that decision starting with the next biennial proceeding. Such a ruling would give NC Power and all other stakeholders time to make a thoroughly thought out and deliberate decision on the appropriate method for calculating long-term fixed energy rates and related issues, including the appropriate contract term given the increased risk to ratepayers.

In its proposed order, the Public Staff stated that a rate that is reset every two years clearly does not qualify as either a fixed rate or as a fixed formula rate. In addition, the Public Staff noted that the FERC's language quoted by NC Power, on page 10 of its reply comments, clearly indicates that the legally enforceable obligation option requires that avoided cost rates be established in advance of the purchase. The petitioner in the arbitration proceeding in Docket No. SP-467, Sub 1, Economic Power and Steam Generation, LLC, clearly indicated that it cannot obtain financing if only the currently approved reset for changes in fuel prices was offered. There is no reason to think that the QFs entitled to the standard contracts would not encounter the same difficulties. The Public Staff concluded that the Commission should require NC Power to file in the next avoided cost proceeding fixed avoided energy rates for five-year, ten-year and 15-year periods for QFs entitled to standard contracts.

Based upon the foregoing, the Commission concludes that NC Power should continue to be required to offer Schedule 19-DRR in addition to its proposed Schedule 19-LMP, subject to the conditions approved in the 2006 avoided cost proceeding, as detailed in the Commission's Order issued on December 19, 2007, in Docket No. E-100, Sub 106. With respect to the reset of avoided energy rates, the Commission agrees with the position of the Public Staff. The Commission also agrees that the required fixed energy rates should be implemented starting with the next biennial proceeding. Therefore, NC Power should be required to file in the next avoided cost proceeding proposed fixed long-term, levelized avoided energy rates for QFs entitled to standard contracts.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 6

No party to this proceeding recommended a change with respect to the rates to be made available to QFs not eligible for the standard long-term levelized rates. The Commission concludes that PEC, Duke, and NC Power should continue to be required to offer QFs not eligible for the standard long-term levelized rates the option of contracts and rates derived by free and open negotiations or, when explicitly approved by Commission Order, participation in the utility's competitive bidding process for obtaining additional capacity. The QF also has the right to sell its energy on an "as available" basis pursuant to the methodology approved by the Commission. Under PURPA, a larger QF is just as entitled to full avoided costs as a smaller QF. The exclusion of larger QFs from the long-term levelized rates in the standard rate schedules was never intended to suggest otherwise.

The Commission has previously ruled that, absent an approved, active solicitation, negotiations between a utility and a larger QF are subject to arbitration by the Commission at the request of either the utility or the QF to determine the utility's actual avoided cost, including both capacity and energy components, as appropriate, as long as the QF is willing to commit its capacity for a period of at least two years. Such arbitration would be less time consuming and expensive for the QF than the previously available complaint process. The Commission concludes that the arbitration option should be preserved.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The Commission has repeatedly affirmed that the peaker method is appropriate for calculating Duke's and PEC's avoided cost rates and the DRR method is appropriate for calculating NC Power's avoided cost rates. No party to this proceeding challenged the appropriateness of these methodologies. For purposes of this proceeding, the Commission concludes that the peaker method and the DRR method are generally accepted and used by the electric utility industry and are reasonable for use in this proceeding. As is its practice, the Commission will address alternative methodologies if and when they are proposed in future avoided cost proceedings.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The Commission has traditionally used a PAF in calculating avoided capacity cost rates for utilities that use the peaker methodology. This adjustment takes into account the fact that a generating facility cannot be in operation at all times. A wholesale power contract typically includes a capacity charge that is calculated on a per-kW basis and is payable regardless of the number of kWh the seller provides. In contrast, the standardized capacity rates for purchases from QFs in North Carolina are calculated on a per-kWh basis. As a result, if rates were set at a level equal to a utility's avoided capacity costs without a PAF, a QF would not receive the full capacity payment to which it is entitled unless it operated 100% of the on-peak hours throughout the year. The PAF is used to increase the capacity rates and, thus, allow a QF to experience a reasonable number of outages and still receive payments equal to the utility's avoided capacity costs. Until the 1996 avoided cost proceeding in Docket No. E-100, Sub 79, the Commission approved a PAF of 1.2 for the calculation of avoided cost rates for all QFs. In its Order approving avoided cost rates in that docket, the Commission approved a PAF of 2.0 for hydro QFs with no storage capability and no other type of generation, which allows such QFs to recover their full capacity payments if they operate 50% of the on-peak hours. The 1.2 PAF used by the Commission in previous cases (for QFs other than run-of-the-river hydro facilities) reflected the Commission's judgment that, if a unit is available 83% of the time, it is operating in a reasonable manner and should be allowed to recover the utility's full avoided costs.

No party to this proceeding proposed any changes to the approved PAFs. Accordingly, the Commission concludes that a PAF of 2.0 should be utilized by PEC and Duke in their respective avoided capacity cost calculations for hydroelectric facilities with no storage capability and no other type of generation and that a PAF of 1.2 should be used for all other QFs.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The Public Staff, in its initial statement, discussed its position that PEC's exclusion of start costs in the calculation of its avoided energy costs and rates was not consistent with PURPA. Noting its discussion of this issue in its filings in the EPCOR/PEC arbitration case in Docket No. E-2, Sub 966, the Public Staff argued that PURPA requires the inclusion of the start costs included in the Total System Cost output from PROSYM in the calculation of on-peak and off-peak marginal energy costs. In this regard, the Public Staff requested the Commission to order PEC to refile its avoided energy rates calculated in this manner. In its reply comments, PEC stated that, after a careful review of the Public Staff's recommendation, it agreed to refile its avoided energy costs using the PROSYM Total System Cost output, which includes start costs. PEC filed Revised Attachments 1 and 2 and Revised Exhibits 2 and 3 and requested that the Commission approve the revised avoided energy rates contained in its revised Rate Schedule CSP-27. The Commission concludes that PEC's avoided energy costs should be calculated using the PROSYM Total System Cost output data, which includes start costs.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 10

In its initial statement, the Public Staff discussed its concerns about the fact that both Duke and NC Power have provisions that make the currently approved avoided cost rates unavailable as of the expected due date for the utilities' filing of proposed new rates in the next biennial avoided cost proceeding. This mechanism replaced the Commission's previous practice of allowing a utility to file a motion to suspend the availability of the currently approved avoided cost rates and tariff, with QFs that had their certificates of public convenience and necessity (CPCNs) as of the date of the motion being entitled to the existing rates. QFs that did not yet have their CPCNs and signed contracts at the new, proposed rates were entitled to have their payments increased if the Commission approved avoided cost rates higher than the rates proposed by the utilities (without being subject to such rates being decreased if lower rates were approved). Given the Commission's recent interpretation of the FERC's regulations in two arbitration proceedings, <u>EPCOR USA North Carolina LLC v. Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc.</u>, in Docket No. E-2, Sub 966 (EPCOR), and <u>Economic Power & Steam Generation, LLC v. Virginia Electric and Power Company, d/b/a Dominion North Carolina Power</u>, in Docket No. SP-467 (EP&S), Sub 1, the Public Staff questioned whether it is consistent with PURPA to end the availability of approved avoided cost rates as of the date new proposed avoided costs rates are expected to be filed.

In its proposed order, the Public Staff stated that it was not sufficient for only variable rates to be made available during the interim between filing and approval of new avoided cost rates given the Commission's interpretation of PURPA in the arbitration proceedings. Because the Commission has decided that QFs that meet certain eligibility requirements are entitled to long-term, levelized avoided cost rates, those QFs cannot be deprived of such options during the pendency of the avoided cost proceeding. The Public Staff concluded that the Commission should return to its previously established policy of the proposed avoided cost rates being available, subject to being increased if the Commission approved higher avoided costs, to QFs that are otherwise eligible to enter into standard contracts between the filing of (not the pre-established due date for) proposed new avoided cost rates and the Commission's approval of new avoided cost rates.

NC Power

According to NC Power, its proposed Schedule 19-DRR is available to any size-eligible QF with a CPCN, if a CPCN is required by the Commission, that enters into a contract and begins deliveries of power on or prior to December 31, 2012 (the Availability Deadline). The Company explained that December 31, 2012, is the Availability Deadline because that is the end of the two-year period forming the basis for the estimated avoided cost rates contained in Schedule 19-DRR (Biennial Period). Thus, a QF that will not begin delivery of power during the Biennial Period (a Non-Period QF) is not eligible for the Schedule 19-DRR rates approved during this proceeding.

NC Power's existing policy with respect to Non-Period QFs is to enter into contracts with such QFs at the rates, terms, and conditions contained in the then-proposed Schedule 19-DRR that covers the applicable Biennial Period, subject to true-up based on the Commission's final order in such biennial proceeding. Applying this policy to the currently proposed Schedule 19-DRR, during the interval between January 1, 2011, and the Commission's order in this proceeding, the Company will enter into contracts with QFs that can meet the Availability Deadline at the rates, terms, and conditions contained in its proposed Schedule 19-DRR. The rates and contract terms would be trued-up to reflect any increase in the rates approved in the Commission's final order in this proceeding. The Company will enter into contracts with Non-Period QFs that cannot meet the Availability Deadline in this proceeding at the rates, terms, and conditions contained in the Schedule 19-DRR as proposed in the biennial proceeding for the future applicable period. NC Power is willing to memorialize its existing policy in Schedule 19-DRR if desired by the Commission.

In its initial statement, the Public Staff questioned whether Schedule 19-DRR's availability limitation was consistent with PURPA in light of recent Commission orders in Docket Nos. E-2, Sub 966 and SP-467, Sub 1. In those orders, which involved QFs that were not eligible for standard rates, the Commission interpreted Section 292.304(d) of FERC's regulations implementing PURPA and held that this regulation gives a QF two options: (a) to sell power "as available," or (b) to sell pursuant to a legally enforceable obligation (LEO) over a specified term. If the QF chooses the LEO option, the QF has the further option of choosing rates based upon avoided costs calculated at the time the LEO is incurred or at the time the power is delivered. Based on its interpretation of these Commission orders, the Public Staff asserted, in effect, that the application of the Availability Deadline to Non-Period QFs is inconsistent with PURPA "when that QF has its CPCN, is eligible for the standard rates, and has indicated that it intends to commit itself." According to NC Power, the Public Staff suggested that if the Commission concludes otherwise, then "at a minimum, the QF qualifying for the standard rates should be entitled to the proposed avoided cost rates, subject to those rates being trued-up if the Commission approved higher rates."

NC Power agreed, as discussed above, that that Non-Period QFs should be entitled to the then-proposed avoided cost rates, subject to being trued-up based on the Commission's final order in a biennial proceeding. NC Power disagrees that the Availability Deadline is inconsistent with PURPA and that Section 292.304(d) should apply in a standard rate context.

NC Power noted that avoided costs determined in the Commission's biennial proceedings are necessarily based on the assumption that QFs will begin power deliveries during the Biennial Period. For example, in this proceeding, NC Power's Schedule 19-DRR rates are all based on the assumption that a QF will start delivering power to the utility in either 2011 or 2012. Accordingly, the avoided capacity rates start in 2011 or 2012, as applicable, and run for five, ten, or 15 years from 2011 or 2012, as applicable. Similarly, with respect to 100 kW or smaller QFs, for which fixed avoided cost energy rates are required, avoided cost energy rates start in 2011 or 2012, as applicable, and run for five, ten, or 15 years from 2011 or 2012, as applicable. There will be no avoided cost rate estimates developed or approved in this proceeding for QFs that begin operating in 2013, 2014, and beyond. Thus, new avoided cost estimates would need to be calculated for the Non-Period QF for years not covered by the Schedule 19-DRR approved in this proceeding using different data and assumptions from those used in the Schedule 19-DRR approved in this proceeding.

NC Power also argued that Section 292.304(d) of the FERC's regulations does not apply in the standard rate context. The Company noted that Schedule 19-DRR is a standard rate approved by the Commission pursuant to its obligation under 18 C.F.R. 292.204(c)(1) to put standard rates into effect for QFs with a design capacity of 100 kW or less. As permitted by 18 C.F.R. 292.304(c)(2), the Commission has expanded standard rates to apply to QFs of 5 MW or less. Standard rates adopted by the Commission are required to be "consistent with paragraphs (a) and (e) of 18 C.F.R. 292.304." In short, according to the Company, Section 292.304(d) is not applicable to Commission-approved standard rates. Moreover, the Company asserted that, even if the Commission were to find Section 292.304(d) applicable in a standard rate context, such a holding would not achieve the result advocated by the Public Staff (i.e., entitling Non-Period QFs to currently-effective Schedule 19-DRR rates).

NC Power noted that Section 292.304(d) provides a QF with the right:

> (1) To provide energy as the qualifying facility determines such energy to be available for such purchases, in which case the rates for such purchases shall be based on the purchasing utility's avoided costs calculated at the time of delivery; or

(2) To provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case the rates for such purchases shall, at the option of the qualifying facility exercised prior to the beginning of the specified term, be based on either:

(i) The avoided costs calculated at the time of delivery; or
(ii) The avoided costs calculated at the time the obligation is incurred.

NC Power stated that the meaning of subsection (d)(2) was at issue in the EPCOR[1] and EP&S proceedings. In its January 26, 2011 Order on Arbitration regarding EP&S (EP&S Order), the Commission held that, under the specific facts of that case, a QF established an LEO in November 2009 because at that time the QF had (1) obtained a CPCN, and (2) made clear to the purchasing utility that it wanted to sell its output. Having established an LEO, the Commission further held that the QF was entitled to avoided cost payments "based upon forecasts using data as of the time the LEO is incurred" (i.e., November 2009).

Thus, under the plain language of 18 C.F.R. 292.304(d)(2)(ii) and consistent with the Commission's rulings in the EP&S proceeding, argued NC Power, a Non-Period QF invoking 18 C.F.R. 292.304(d)(2) would not be entitled to the currently effective Schedule 19-DRR. Instead, that QF would be entitled to avoided costs calculated at the time the obligation is incurred and based upon forecasts using data as of the time the LEO is incurred. For example, a Non-Period QF that established an LEO in October 2012 for a facility that would begin delivering power in December 2014 would not be entitled to avoided cost rates approved in this proceeding, but rather avoided cost calculated at the time of the LEO. Further, such avoided cost estimates would be based upon forecasts using data available in October 2012, not forecasts based on the data used in this proceeding. NC Power argued that, in short, there would be potentially endless rounds of calculations of avoided costs as of each QF's LEO, which would defeat the whole purpose of establishing standard rates. In sum, NC Power argued that artificially grafting 18 C.F.R. 292.304(d) onto the standard rate context would not entitle a QF to the currently-approved standard rates, and would embroil the Commission and the relevant utility into myriad individual rate setting proceedings. This result would entirely contradict the rationale for standard rate options, which is to allow small QFs, and utilities, to avoid the transactional cost of individual rate estimates and contract negotiations.

Based on the record in this proceeding, the Commission agrees with NC Power that limiting the availability of Schedule 19-DRR rates to QFs that can deliver power during the Biennial Period is reasonable, consistent with PURPA and Commission orders implementing PURPA, and should continue to be approved. In addition, the Commission concludes that NC Power's policy with respect to Non-Period QFs is reasonable.

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[1] NC Power's analysis focused on the EP&S proceeding because it involved an unconstructed QF. The EPCOR proceeding involved two already-constructed and operating QFs. It is entirely within the control of already-operating QFs that meet the other eligibility requirements for Schedule 19-DRR to meet the Availability Deadline.

Duke

In its initial and revised initial statements, Duke stated that its proposed Schedules PP(H) and PP(N) update the Capacity Credits and Energy Credits to reflect the most recent projections of Duke's avoided capacity and energy costs. To make standard rates available to QFs during the time that the next proceeding is pending, while still recognizing that new rates will be based on more current avoided cost projections, Schedules PP(N) and PP(H) reflect that the fixed long-term rates will be available only to customers under contract with the Company on or before November 1, 2012, and the variable rates will remain available until new fixed long-term rates are approved. Citing the Commission's 2007 avoided cost Order, Duke noted that the Commission had previously approved inclusion of this provision in that biennial cost proceeding.

In its reply comments, Duke recounted the procedural history of its proposal in Schedules PP(H) and PP(N). In the 1994 avoided cost proceeding, Docket No. E-100, Sub 74, the Commission allowed a utility to file a motion to suspend the availability of its currently approved cost rates and tariff. QFs that had their CPCNs as of the date of the motion were entitled, however, to the existing rates. QFs without CPCNs that signed contracts at the new, proposed rates were entitled to have their payments increased if the Commission approved avoided cost rates higher than the rates proposed by the utilities. If the Commission approved lower rates, however, the Commission would not permit the utilities to decrease the payments to the QFs.

In the 1996 avoided cost proceeding, Docket No. E-100, Sub 79, the Company requested that the Schedule PP rates be available only to QFs entering contracts on or before the 1998 due date for the next biennial proceeding, for delivery on or before May 4, 2001. The Company argued that allowing its request would better ensure that the avoided costs rates reflect current avoided costs, noting that even with that time limitation, nearly four years could elapse from the time that avoided costs were estimated until delivery begins. The Commission approved the Company's request by Order issued June 19, 1997. Therefore, until 2007, the availability of Schedule PP expired upon the filing of new proposed avoided cost rates in the next biennial proceedings.

In the 2006 avoided cost proceeding, Docket No. E-100, Sub 106, however, the Company requested to modify the expiration of Schedule PP. To make standard rates available to QFs during the time the next biennial proceeding was pending, while recognizing that the new rates would be based upon more current avoided cost projections, Duke proposed that the fixed long-term rates be available only to customers under contract with the Company on or before November 1, 2008, and that the variable rates remain available until new fixed long-term rates were approved.

The Company proposes to do the same for the next biennial proceeding. The proposed provision reads as follows:

> The Fixed Long-Term Rates on this Schedule are available only to Customers under contract with the Company on or before November 1, 2012 for delivery of power beginning on or before the earlier of thirty (30) months from the date of execution of the contract or May 1, 2015.

According to Duke, this provision makes standard rates available to QFs during the time the next proceeding is pending, while recognizing that the new rates will be based upon more current avoided cost projections. In other words, Duke proposes to continue its currently approved procedure of making its variable rates that are approved by the Commission in this proceeding available to QFs until the Commission approves new fixed long-term rates in the next biennial proceeding. Furthermore, customers that execute contracts containing the variable rates after expiration of the long-term rates on Schedules PP(N) and PP(H) may then amend their contracts to select one of the long-term rates for which they are eligible, once new avoided cost rates are approved by the Commission.

Duke noted that its experience has shown that a utility's filing to lower its avoided cost rates sometimes prompts QFs to try to "lock in" at the current higher rates before the Commission acts. Duke's provision, however, allows for long-term avoided costs rates offered to the QFs to more closely align to actual avoided costs, instead of simply providing a potential for QFs seeking to enter into contracts after November 1, 2012, to "game" the system.

According to Duke, the Commission's conclusions in the recent arbitrations do not require Duke to make available its fixed long-term rates that were calculated prior to November 2010 to QFs seeking a contract after November 1, 2012. Instead, PURPA and the regulations promulgated from it require the avoided costs rates for purchases by electric utilities "shall be just and reasonable to the electric consumers of the electric utility and in the public interest" and shall not exceed the utilities' avoided costs. PURPA 210(b); 18 C.F.R. 292.304(a). Duke stated that, if a QF seeks a contract with Duke after November 1, 2012, the QF may obtain the variable rates approved in this docket that will be in effect until the Commission approves the Company's proposed, calculated avoided cost rates, including fixed long-term rates, in the next biennial proceeding. After that determination is made, the QF may amend its contract to opt into the approved, long-term rates for which it is eligible. Duke argued that this prevents exposing the utility and the ratepayers to paying for longer periods of time avoided costs rates that are in excess of the utility's actual avoided costs. According to Duke, Exhibit 6 to Duke's initial statement shows that most of the Company's PPAs with QFs are at variable rates, and, therefore, the Company's provision also better reflects its experience with QFs in this respect.

The Commission notes that in its Order in the 2006 avoided cost proceeding, it offered the following discussion and conclusions regarding this issue:

> In Docket No. E-100, Sub 79, and subsequent avoided cost proceedings, the Commission has authorized Duke to include in Rate Schedules PP(H) and PP(N) language under which the rates provided therein will be available only to customers under contract with the company on the date of its next biennial avoided cost filing. (In the existing schedules approved for Duke by the Commission in 2005, that date is November 1, 2006.) This language was added to prevent QFs from gaming the system by taking advantage of differences between the existing rates and the proposed rates for the following biennium. The result is that, during the period between the filing of proposed new avoided cost rates and the Commission's order ruling on those rates, Duke is unable to enter into long-term contracts with QFs at standard rates and is also unable to purchase energy from QFs at variable rates. In its initial statement in this proceeding, Duke

proposed to modify Rate Schedules PP(H) and PP(N) so that the long-term rates provided in the schedules will still be available only to QFs under contract with the company on November 1, 2008 (the date of the next avoided cost filing), but variable rates for energy purchases will remain available until new variable rates are approved. If a QF enters into a contract for sales under variable rates during the period between November 1, 2008 and the issuance of the Commission's order ruling on the proposed rates, the QF will have the option of converting to any of the newly approved long-term rates once the Commission's order is issued or, if the QF elects to remain on variable rates, the previously existing variable rates will be superseded by the newly approved ones. Neither the Public Staff nor any other party objected to this modification to Rate Schedules PP(H) and PP(N) and the Commission finds that is it reasonable and should be approved.

The Commission continues to agree with the arguments put forth by Duke and the reasoning stated in the Commission's decision in the 2006 avoided cost proceeding and concludes that Duke's current treatment of this issue remains reasonable.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 11

PEC argued that the applicable federal laws and regulations require the Commission to balance the dual and competing interests of encouraging QFs and its duty to ensure that a utility's avoided cost rates are just and reasonable to the electric utility's customers and are in the public interest. 18 C.F.R. 292.304(a). To achieve such a balance, PEC recommended that the Commission establish a viability prerequisite as a condition for determining the date of an LEO. The viability prerequisite would require that a QF be ready, willing, and able to enter into a contract within 12 months of any LEO. PEC claimed that this would ensure that QFs are not allowed to unfairly lock in higher rates to the detriment of the utility's customers.

According to the Public Staff, this would require a QF to make a very substantial showing that could include, among other things, its net worth, the number of its employees, whether all necessary permits and approvals had been obtained, whether the QF had engaged consultants, and whether the QF had consulted with lending institutions. In its proposed order, the Public Staff argued that the Commission had previously rejected requiring more information than required by the CPCN application process and should continue to reject such requirements in the context of when an LEO has occurred.

PEC explained that, while the determination of the LEO is up to the states, the FERC has stressed that the states are still confined to the requirements of PURPA, which require that "the rates for qualifying facilities shall: (1) be just and reasonable to the electric utility's consumers and in the public interest; and (2) not discriminate against qualifying cogenerators or small power producers." PURPA 210(b); 18 C.F.R. 292.304(a). In considering this provision of PURPA in a case on appeal from the Idaho Public Utilities Commission involving the avoided cost rate to be paid by PacifiCorp to the owner of a 40-MW QF, the Supreme Court of Idaho stated that "a balance must be struck between the local public interest of a utility's electric consumers and the national public interest in development of alternative energy sources." Rosebud Enter., Inc. v. Idaho Pub. Utils. Comm'n, 917 P.2d 766, 770-71 (1996). PEC noted that, in pursuit of this balance, the interpretation of the "just and reasonable" language has spawned brisk debate in many jurisdictions.

PEC explained in its reply comments that, when determining whether an LEO exists in North Carolina, the Commission relies upon (1) the date when the QF committed to sell its generation and (2) the date when the QF had a CPCN. In the EP&S Order, the "commitment to sell" criteria was addressed by the Commission by stating that "[a] 'legally enforceable obligation' does not require a signed contract, but the QF must be ready, willing and able to sign a contract." However, the Commission did not clarify what factors contribute to the determination that a QF is "ready willing and able to sign a contract," or specify any limitation on the pendency of such determination once it is established.

PEC then concluded that, in order to prevent post hoc justifications of when a "commitment to sell" is made, it is appropriate to incorporate a viability criterion into the determination of the date of the LEO to prevent a QF from unfairly locking in avoided cost rates that do not accurately reflect the costs the utility expects to avoid during the period the QF supplies electricity to the utility. According to PEC, this will, in turn, ensure that a "just and reasonable" rate is established consistent with PURPA regulations.

According to PEC, incorporating a viability prerequisite standard will ensure that a utility and its customers will be in the same or similar positions as they would have been were they not required to purchase from the QFs, which is entirely consistent with the Supreme Court's interpretation of the "just and reasonable" standard. Specifically, for purposes of establishing an LEO and the corresponding avoided cost rates, the QF must be ready, willing, and able to enter into a contract within twelve months.

The Public Staff argued that the Commission should not reverse its prior decisions with respect to when an LEO has occurred based upon reply comments by one party.

The Commission concludes that it would be inappropriate to revisit in this proceeding the Commission's prior decisions as to when an LEO has occurred. The issue in this proceeding is the availability of standard contracts and long-term levelized rates to specified QFs contracting to sell 5 MW or less. It would be entirely inappropriate to require such small QFs to meet the higher standard proposed by PEC, and they certainly should not be required to meet a higher standard than the larger QFs in the arbitration proceedings were required to meet. Accordingly, PEC's proposed incorporation of a viability prerequisite for QFs into the current framework is rejected.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The fifth paragraph of NC Power's Schedule 19-DRR PPA deals with a situation in which a regulatory body with jurisdiction, such as this Commission, the Virginia State Corporation Commission (VSCC), or FERC issues an order (a Regulatory Order) that (1) prohibits rate recovery of payments made to a QF, and/or (2) requires NC Power to refund to its ratepayers payments already made to a QF (the Regulatory Disallowance Clause). In the event of such a Regulatory Order, the Regulatory Disallowance Clause provides that rates under the PPA will be reset on a prospective basis at the levels that NC Power is allowed to recover in rates. Further, if a

Regulatory Order requires NC Power to refund to ratepayers previous payments to a QF, then the QF is similarly required to refund to NC Power those amounts. The Commission has approved standard Schedule 19-DRR PPAs containing clauses similar to the Regulatory Disallowance Clause at least since the 1996 avoided cost proceeding in Docket No. E-100, Sub 79.

The Public Staff, in its initial statement, stated that, given that a standard agreement for renewable QFs contracting to sell 5 MW or less is all that is involved, such a provision seemed unwarranted and likely to discourage QF development. In addition, the Public Staff argued that this requirement has the effect of changing the rate paid to the QF because of subsequent regulatory action, which was rejected in 1983 in Docket No. E-100, Sub 41 when language was proposed that would have allowed existing standard contracts to be amended as the result of subsequent governmental or judicial action.

NC Power's position is that the Regulatory Disallowance Clause is warranted and that there is no evidence that the clause has discouraged QF development. NC Power noted that its purchase of energy and capacity from QFs is not optional. Currently, pursuant to PURPA, and the rules, regulations, and orders of this Commission, the VSCC and FERC, NC Power has a mandatory obligation to purchase energy and capacity from QFs of 20 MW or less at the Company's avoided cost, on the theory that the development of QFs provides a societal benefit.

Because NC Power is legally required to purchase energy and capacity from QFs, there should never be, according to NC Power, an order disallowing rate recovery of those QF payments. While the risk of such a disallowance is remote, NC Power noted that the risk is real, and offers as evidence two instances where either this Commission or the VSCC did in fact disallow rate recovery of QF payments. NC Power asserted that there is no principled reason for this remote but real risk to be borne solely by itself or to force it and its shareholders to continue to make uncompensated payments to the QF following a Regulatory Order.

With respect to the Public Staff's assertion that the Regulatory Disallowance Clause is "likely to discourage QF development," NC Power noted that nothing in the record of this proceeding supports that assertion. NC Power also noted, citing, for example, Freehold Cogeneration Assocs. v. Board Of Regulatory Comm'rs of New Jersey, 44 F.3d 1178 (3d. Cir. 1995), that QFs and their lenders know, as does NC Power, that a regulatory disallowance is a remote possibility under existing law and precedent.

Finally, NC Power noted that the Commission has approved standard Schedule 19-DRR PPAs containing a clause similar to the Regulatory Disallowance Clause since at least 1997, which was well after its April 1, 1983 order in Docket No. E-100, Sub 41 raised by the Public Staff.

Based on the record in this proceeding, the Commission finds that NC Power's inclusion of a regulatory disallowance clause in its Schedule 19-DRR is reasonable and should be allowed.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 13

Except as discussed otherwise herein, the rate schedules and standard contract terms and conditions proposed in this proceeding by PEC, Duke, and NC Power were not opposed. They should be approved except as otherwise discussed herein. The utilities should be required to file new versions of their rate schedules and standard contracts, in compliance with this Order, within 20 days after the date of this Order. They should be allowed to go into effect ten days after they have been filed. The utilities' filings should stand unless specific objections as to the accuracy of the calculations and conformity to the decisions herein are filed within that ten-day period.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 14

In the cover letter to its proposed order, the Public Staff indicated that it had begun its investigation of New River's proposed avoided cost rates, as revised, but that the rates as filed presented a number of difficult issues. Given J.D. Wind and the Commission's recent interpretations of PURPA with the FERC cases in mind, the Public Staff indicated that issues also were raised about the appropriateness of WCU's proposed formula rates and lack of long-term rate options. The Public Staff proposed to make a separate filing with respect to the appropriate avoided cost rates and standard contracts for both WCU and New River.

On May 12, 2011, the Public Staff filed a letter in this docket stating that, since filing its proposed order, it has been in communication with counsel for New River, with the consultant for New River and WCU, and with counsel for Duke, which is the requirements supplier at wholesale to Blue Ridge Electric Membership Corporation (Blue Ridge). The Duke/Blue Ridge PPA treats New River's native load as if it were Blue Ridge's native load for purposes of Duke's obligations vis-a-vis Blue Ridge, thus involving Duke and the terms of the Blue Ridge PPA in the discussion.

A complicating factor in the process was the existence of a QF waiting to sign a PPA with New River. New River has since informed the Public Staff that the QF, which is participating in the NC GreenPower program, is willing to proceed under the formula rates as filed. As a result, more time can be taken to resolve the outstanding issues. In its May 12 letter to the Commission, the Public Staff proposed to continue working with the relevant parties and then to make a filing in several months with respect to the appropriate avoided cost rates and standard contracts for both WCU and New River. In the meantime, the Public Staff recommended that the Commission approve WCU's and New River's avoided cost rate schedules, as filed, on an interim basis pending further resolution of the issues described in the Public Staff's proposed order transmittal letter filed April 29, 2011, and further order of the Commission.

Based upon the foregoing, the Commission concludes that the avoided cost rates for WCU and New River, as filed, should be approved on an interim basis pending further order of the Commission.

IT IS, THEREFORE, ORDERED as follows:

1. That PEC shall offer long-term levelized capacity payments and energy payments for five-year, ten-year and 15-year periods as standard options to (a) hydroelectric qualifying facilities owned or operated by small power producers as defined in G.S. 62-3(27a) contracting to sell 5 MW or less capacity and (b) non-hydroelectric qualifying facilities fueled by trash or methane derived from landfills, hog waste, poultry waste, solar, wind, and non-animal forms of biomass contracting to sell 5 MW or less capacity. The standard levelized rate options of ten and

15 years shall include a condition making contracts under those options renewable for subsequent terms at the option of the utility on substantially the same terms and provisions and at a rate either (1) mutually agreed upon by the parties negotiating in good faith and taking into consideration the utility's then avoided cost rates and other relevant factors or (2) set by arbitration. PEC shall offer its standard five-year levelized rate option to all other qualifying facilities contracting to sell 3 MW or less capacity.

2. That Duke shall offer long-term levelized capacity payments and energy payments for five-year, ten-year and 15-year periods as standard options to (a) hydroelectric qualifying facilities owned or operated by small power producers as defined in G.S. 62-3(27a) contracting to sell 5 MW or less capacity and (b) non-hydroelectric qualifying facilities fueled by trash or methane derived from landfills, hog waste, poultry waste, solar, wind, and non-animal forms of biomass contracting to sell 5 MW or less capacity. The standard levelized rate options of ten and 15 years shall include a condition making contracts under those options renewable for subsequent terms at the option of the utility on substantially the same terms and provisions and at a rate either (1) mutually agreed upon by the parties negotiating in good faith and taking into consideration the utility's then avoided cost rates and other relevant factors or (2) set by arbitration. Duke shall offer its standard five-year levelized rate option to all other qualifying facilities contracting to sell 3 MW or less capacity.

3. That NC Power shall offer long-term levelized capacity payments and energy payments calculated pursuant to the DRR method based on long-term levelized generation mixes with adjustable fuel prices for five-year, ten-year and 15-year periods as standard options to (a) hydroelectric qualifying facilities owned or operated by small power producers as defined in G.S. 62-3(27a) contracting to sell 5 MW or less capacity and (b) non-hydroelectric qualifying facilities fueled by trash or methane derived from landfills, hog waste, poultry waste, solar, wind, and non-animal forms of biomass contracting to sell 5 MW or less capacity. The standard levelized rate options of ten and 15 years shall include a condition making contracts under those options renewable for subsequent terms at the option of the utility on substantially the same terms and provisions and at a rate either (1) mutually agreed upon by the parties negotiating in good faith and taking into consideration the utility's then avoided cost rates and other relevant factors or (2) set by arbitration. The standard five-year levelized rate option shall be offered to all other qualifying facilities contracting to sell 3 MW or less capacity. Long-term levelized energy payments should be offered as an additional option for small qualifying facilities rated at 100 kW or less capacity.

4. That NC Power may offer, as an alternative to avoided cost rates derived using the DRR method, avoided cost rates based upon market clearing prices derived from the markets operated by PJM, subject to the following conditions: (a) any QF choosing to enter into a contract using the PJM market pricing method shall be allowed to terminate its existing Schedule 19-LMP contract without paying termination charges after the first year upon 90 days prior written notice, and, after doing so, enter into a new two-, five-, ten-, or 15-year Schedule 19-DRR contract, at its option, and (b) NC Power shall calculate avoided cost payments using each method on a monthly basis for the next two years and provide the comparison to each QF in North Carolina that is receiving payment under either of the two rate schedules approved in this Order at least once every six months, with the first report due no later than eight months from the

QF's contract date. NC Power shall file these comparisons with the Commission in this docket at the time they are provided to the QFs.

5. That NC Power shall provide a comparison of the DRR method and the PJM market pricing method in the next biennial avoided cost proceeding. As part of this comparison, NC Power shall (a) file PJM prices during each relevant summer season; (b) identify the five peak hours that were used in the SPPF; (c) file the PJM input data for each of the five coincident peak hours; and (d) file a comparison of the payments a QF would have received for one year, including the first full summer following the date of this Order, under the DRR method and under the PJM market pricing method; assuming various levels of hypothetical outages during the five coincident peak hours during the preceding summer.

6. That PEC, Duke, and NC Power shall offer QFs not eligible for the standard long-term levelized rates the following three options if the utility has a Commission-recognized active solicitation underway: (1) participating in the utility's competitive bidding process, (2) negotiating a contract and rates with the utility, or (3) selling energy at the utility's Commission-established variable energy rate. If the utility does not have a Commission-recognized active solicitation underway, it shall offer QFs not eligible for the standard long-term levelized rates the options of (1) contracting with the utility to sell power at the variable energy rate established by the Commission in these biennial proceedings or (2) contracting with the utility to sell power at negotiated rates. If the utility does not have a solicitation underway, any unresolved issues arising from such negotiations will be subject to arbitration by the Commission at the request of either the utility or the QF in order to determine the utility's actual avoided cost, including both capacity and energy components, as appropriate; however, the Commission will only arbitrate disputed issues if the QF is prepared to commit its capacity to the utility for a period of at least two years. In either case, whether there is an active solicitation underway or not, QFs not eligible for the standard long-term levelized rates have the option of selling into the wholesale market. The exact points at which an active solicitation should be regarded as beginning and ending for these purposes shall be determined by motion to, and order of, the Commission. Unless there is such a Commission order, it will be assumed that there is no solicitation underway. If the variable energy rate option is chosen, such rate may not be locked in by a contract term, but shall instead change as determined by the Commission in the next biennial proceeding.

7. That a PAF of 2.0 shall be utilized by both PEC and Duke in their respective avoided cost calculations for hydroelectric facilities with no storage capability and no other type of generation.

8. That a PAF of 1.2 shall be utilized by both PEC and Duke for all QFs that do not qualify for a PAF of 2.0 as set forth above.

9. That PEC's avoided energy costs shall be calculated using the PROSYM Total System Cost output data, which includes start costs.

10. That NC Power's inclusion of a regulatory disallowance clause in its standard contract for purchases of energy and capacity pursuant to Schedule 19-DRR is reasonable and shall continue to be allowed.

11. That contract clauses currently in place by Duke and NC Power that limit the availability of standard long-term contract rates in the time period immediately prior to the approval of new biennial rates are reasonable and shall continue to be allowed.

12. That PEC's proposed incorporation into the current framework of a viability prerequisite for QFs is hereby rejected.

13. That NC Power shall file in the next avoided cost proceeding proposed fixed long-term, levelized avoided energy rates for QFs entitled to standard contracts.

14. That the rate schedules and standard contract terms and conditions proposed in this proceeding by PEC, Duke, and NC Power are hereby approved except as otherwise discussed herein. The utilities shall file new versions of their rate schedules and standard contracts, in compliance with this Order, within 20 days after the date of this Order. Such rate schedules and standard contracts shall go into effect ten days after they have been filed unless specific objections as to the accuracy of the calculations and conformity to the decisions herein are filed within that ten-day period.

15. That the avoided cost rates for WCU and New River, as filed, are approved on an interim basis pending further order of the Commission.

ISSUED BY ORDER OF THE COMMISSION.
This the __27th__ day of July, 2011.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

kh072611.01

DOCKET NO. E-100, SUB 128

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Investigation of Integrated Resource Planning in North Carolina - 2010	) ORDER APPROVING 2010 BIENNIAL) INTEGRATED RESOURCE PLANS AND) 2010 REPS COMPLIANCE PLANS

HEARD: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on Monday, January 24, 2011, at 7 p.m.

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

APPEARANCES:

For Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc.:

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For Duke Energy Carolinas, LLC:

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BY THE COMMISSION: Integrated Resource Planning (IRP) is intended to identify those electric resource options that can be obtained at least cost to the ratepayers consistent with 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.

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). G.S. 62-110.1 further requires the Commission to consider this analysis in acting upon any petition for construction. 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: (1) a report of the Commission's analysis and plan; (2) the progress to date in carrying out such plan; and (3) the program of the Commission for the ensuing year in connection with such plan. G.S. 62-15(d) requires the Public Staff to assist the Commission in this analysis and plan.

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....

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' IRP. Commission Rule R8-60 requires that each of the investor-owned utilities, the North Carolina Electric Membership Corporation, and any individual electric membership corporation to the extent that it is responsible for procurement of any or all of its individual power supply resources (hereinafter, collectively, the electric utilities) 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 Renewable Energy and Energy Efficiency Portfolio Standard (REPS) compliance plan as part of its IRP report. Within 150 days after the filing of each electric utility's biennial report, and within 60 days after the filing of each electric utility's annual report, the Public Staff or any other intervenor may file its own plan or an evaluation of, or comments on, the electric utilities' IRP 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 2010 biennial integrated resource plans (IRPs) were filed by the following investor-owned utilities (IOUs): Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc. (PEC); Duke Energy Carolinas, LLC (Duke); Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (DNCP); and the electric membership corporations (EMCs): North Carolina Electric Membership Corporation (NCEMC); Rutherford EMC (Rutherford), Piedmont EMC (Piedmont), Haywood EMC (Haywood), and EnergyUnited EMC (EU). In addition, REPS compliance plans were submitted by the IOUs, GreenCo Solutions, Inc. (GreenCo),[1] Halifax EMC (Halifax), and EU.

In addition to the Public Staff, the following parties have intervened in this docket: the Carolina Industrial Group for Fair Utility Rates I, II, and III (CIGFUR); the North Carolina Sustainable Energy Association (NCSEA); the Public Works Commission of the City of Fayetteville (Fayetteville); Nucor Steel-Hertford (Nucor); the North Carolina Waste Awareness & Reduction Network (NC WARN); the Southern Alliance for Clean Energy (SACE); and the Carolina Utility Customers Association, Inc. (CUCA). The intervention of the Attorney General is recognized pursuant to G.S. 62-20.

Procedural History

On August 20, 2010, Rutherford filed a letter indicating that it had a long-term power supply agreement with Duke, its load would be reported for filing purposes within Duke's IRP, its renewable energy requirements under the REPS would be provided by Duke, and its REPS requirements would be reflected in Duke's 2010 REPS compliance plan. Also on August 20, 2010, PEC moved to extend the filing date for its IRP to September 12, 2010. This motion was granted by the Commission on September 1, 2010. On August 27, 2010, EU filed its 2010 IRP and its 2010 REPS compliance plan. On August 31, 2010, Halifax filed for an extension of time to file its 2010 REPS compliance plan. The Commission by Order issued on September 14, 2010, granted Halifax an extension up to and including October 15, 2010. On August 31, 2010, Haywood filed its 2010 IRP. On September 1, 2010, Duke and DNCP filed their 2010 IRPs and REPS compliance plans; GreenCo filed a compliance plan on behalf of its members; and Piedmont, NCEMC, and Rutherford filed their 2010 IRPs. On September 13, 2010, PEC filed its 2010 IRP and REPS compliance plan. On October 15, 2010, Halifax filed its 2010 REPS compliance plan.

By Order dated December 3, 2010, the Commission scheduled a public hearing for January 24, 2011, on the filed IRPs and REPS compliance plans. On December 13, 2010, SACE

[1] GreenCo filed a consolidated 2010 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.

requested an evidentiary hearing on issues to be identified by the Commission. On December 17, 2010, NC WARN made a filing in support of SACE's request for an evidentiary hearing. On December 28, 2010, PEC moved that the Commission delay ruling on SACE's request until SACE and NC WARN had identified elements of the electric utilities' IRPs with which they disagree and allow parties to respond to the identification of issues. On January 13, 2011, the Public Staff moved that the deadline for the filing of comments on IRPs be extended to February 10, 2011. The Commission granted this Motion on January 19, 2011.

The public hearing was held as scheduled on January 24, 2011. The public witnesses in attendance testified in support of energy efficiency (EE) and renewable energy technologies, in opposition to coal and nuclear generation, and against rate increases.

On February 9, 2011, DNCP filed an updated 2010 REPS compliance plan. On February 10, 2011, comments were filed by the Public Staff and SACE. On February 11, 2011, comments were filed by NC WARN. Both SACE and NC WARN requested that the Commission hold an evidentiary hearing on the IRPs of Duke and PEC.

On February 23, 2011 Duke moved that the deadline for filing reply comments be extended until March 1, 2011. The Commission granted the motion on February 24, 2011.

On March 1, 2011, reply comments were filed by Blue Ridge EMC (Blue Ridge), PEC, Duke, and DNCP addressing the comments of the Public Staff, SACE, and NC WARN. On March 3, 2011, Blue Ridge submitted a corrected version of its reply comments. On March 10, 2011, the Public Staff clarified two items in its February 10, 2011 comments.

On April 14, 2011, the Commission issued an Order Denying Request for Evidentiary Hearing. On April 29, 2011, NC WARN filed a Motion for Reconsideration of that order, to the limited extent of allowing parties to file proposed orders or briefs before the Commission issues its final order in this proceeding. On May 2, 2011, Duke filed a supplemental response to the Public Staff's initial comments. On May 5, 2011, the Commission issued an Order allowing parties to file proposed orders or briefs.

On June 6, 2011, the following parties submitted briefs or proposed orders: PEC, Duke, DNCP, NC WARN, and SACE. Also on June 6, 2011, NCSEA submitted comments. The Public Staff did not submit a brief or proposed order in this proceeding.

On June 14, 2011, Duke filed an Objection to NCSEA's Comments Filing. In Duke's objection, it requested that the Commission reject NCSEA's filing as grossly out of time. On June 17, 2011, NCSEA submitted a Reply to Duke's Objection to NCSEA's Comment Filing. According to NCSEA, its comments were firmly grounded in the record and, like a brief, consisted of contentions based on the record evidence. Upon review of these filings, the Presiding Commissioner concluded that NCSEA's comments should be treated as a brief. As such, NCSEA could not raise new issues in its filing because they should have been filed within the time allowed for comments on the utilities' IRPs. Therefore, only arguments asserted by NCSEA regarding issues previously raised in comments submitted by the Public Staff and the other intervenors were allowed and taken into consideration by the Commission in reaching its decision in this docket.

Based upon the foregoing, the information contained in the 2010 biennial IRPs, the 2010 REPS compliance plans, the comments and reply comments, and the Commission's entire record of this proceeding, the Commission makes the following:

FINDINGS OF FACT

1. 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 thus produced are reasonable for purposes of this proceeding and should be approved.

2. The IOUs' 2010 biennial IRP reports are reasonable and should be approved.

3. The IOUs' 2010 REPS compliance plans are reasonable and should be approved.

4. The 2010 biennial IRP reports and 2010 REPS compliance plans submitted by NCEMC, Piedmont, Rutherford, EU, Haywood, GreenCo, and Halifax are reasonable and should be approved.

5. PEC and Duke have adequately addressed the issues raised by SACE and NC WARN in this proceeding including the proper evaluation of EE and demand-side management (DSM) resources, least cost portfolio selection, peak demand and energy growth projections, baseload requirements, the cost of new nuclear generation, greenhouse gas (GHG) emissions, and the potential economic viability of existing scrubbed coal units.

6. PEC has provided adequate information in this proceeding related to the planned retirements of its coal-fired generating units.

7. PEC and Duke have provided adequate information in this proceeding regarding their reserve margins, as required by Rule R8-60(i)(3).

8. Duke should file in the respective dockets of each affected DSM program and pilot a calculation showing the difference between the avoided cost capacity and energy benefits, as originally filed, and the avoided cost benefits recalculated using the correct DSMore model calculation methodology.

9. The loads of French Broad EMC (French Broad) and Blue Ridge are reflected in the IRPs filed by NCEMC and Duke, respectively, and French Broad and Blue Ridge are not required to file individual IRPs.

10. All EMCs should include a full discussion in future biennial IRPs of their DSM programs and their use of these resources as required by Rule R8-60(i)(6).

11. If Piedmont determines that its smart meter program is an EE program, it should file for Commission approval of the program pursuant to Rule R8-68.

12. In future biennial IRPs, EU should provide a more detailed description of the participation and savings related to specific DSM and EE programs, particularly those its proposes to use to meet its REPS obligations.

13. PEC and Duke should each prepare a comprehensive reserve margin requirements study and include these as part of their 2012 biennial IRP reports. PEC and Duke should keep the Public Staff updated as they develop the parameters of the studies.

14. Each IOU and EMC should investigate the value of activating 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. This issue should be addressed as a specific item in their 2012 biennial IRP reports.

15. Each electric utility should use appropriately updated DSM/EE market potential studies.

16. The current scenarios relating to carbon emissions, as provided in the IRPs, are responsive and appropriate for purposes of this proceeding.

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

Peak and Energy Forecasts

In the Public Staff's comments, it stated that all of the electric utilities use accepted econometric and end-use analytical models to forecast their peak and energy needs. 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 has reviewed the electric utilities' 15-year peak and energy forecasts (2011–2025). The compound annual growth rates (CAGRs) for the forecasts of PEC, Duke, and DNCP are within the range of 1.2% to 1.8%. The CAGRs for NCEMC and the four independent EMCs that filed IRPs (EU, Haywood, Piedmont, and Rutherford) are within the range of 1.2% to 2.2%.

PEC

The Public Staff's one-year review of PEC's peak load accuracy shows that the predictions in the 2009 IRP represent a forecast with less than a 1% error.[1] The low forecast error rate was, in part, due to the system-wide average temperature of 96 degrees Fahrenheit, which was approximately equal to PEC's normal peak-day temperature. The Public Staff's five-year

[1] The Mean Absolute Error is used to calculate the forecast error.

review of PEC's peak load and energy sales forecasting accuracy shows that the predictions in the 2005 IRP were reasonably accurate with less than a 5% forecast error.

The Public Staff believes that the economic, weather, and demographic assumptions that underlie PEC's peak and energy forecasts are reasonable and that PEC has employed accepted statistical and econometric forecasting practices. In conclusion, the Public Staff believes that PEC's peak load and energy sales forecasts are reasonable for planning purposes.

Duke

The Public Staff's one-year review of Duke's peak load accuracy shows that the predictions in the 2009 IRP represent a forecast with less than a 2% error. The system-wide average temperature was 93 degrees Fahrenheit, which was approximately one degree cooler than the normal peak-day temperature. The Public Staff's five-year review of Duke's energy sales forecasting accuracy shows that the predictions in Duke's 2005 IRP were reasonably accurate with less than a 5% forecast error. However, the forecast accuracy of Duke's peak loads reflected a 5.7% forecast error. The above-average forecast error for the five-year period results from the relatively low actual peak loads reported in 2009 and 2010, which were more than 8% below the predicted peak loads. These two forecast errors were mainly due to a reduction in new customers in 2010 and an even larger reduction in new customers in 2009. Duke's 2010 forecast more accurately reflects the current economic environment.

The Public Staff believes that the economic, weather, and demographic assumptions that underlie Duke's peak and energy forecasts are reasonable, and that Duke has employed accepted statistical and econometric forecasting practices. In conclusion, the Public Staff believes Duke's forecasts are reasonable for planning purposes.

DNCP

The Public Staff's one-year review of DNCP's peak load accuracy shows that the predictions in the 2009 IRP represent a forecast with less than a 1% error. The Public Staff's five-year review of DNCP's peak load and energy sales forecasting accuracy shows that the predictions in the 2005 IRP were reasonably accurate with less than a 5% forecast error.

The Public Staff believes that the economic, weather, and demographic assumptions that underlie DNCP's peak and energy forecasts are reasonable, and that DNCP has employed accepted statistical and econometric forecasting practices. In conclusion, the Public Staff believes that DNCP's peak load and energy sales forecasts are reasonable for planning purposes.

NCEMC

The Public Staff's analysis of NCEMC's peak load forecasting accuracy over the past five years indicates that the forecasts in its 2005 annual report were on average 247 MW lower than its actual system load, which equates to a 8% forecast error. Its energy sales forecast has been reasonably accurate with less than a 5% error rate. In response to the Commission's Order in Docket No. E-100, Sub 124, NCEMC reworked its load forecasting method by partnering with

SAS Institute, Inc., to develop new state-of-the-art statistical models. The new peak demand models implemented by NCEMC are based on usage per customer and allow for the quantification of changes in peak demand among each of its member cooperatives that are attributable to changes in weather conditions and other factors. The Public Staff is cautiously optimistic that its concerns expressed in prior IRP dockets about the accuracy of NCEMC's forecasting methods will be resolved by this new forecasting process; however, it will still be necessary to review the forecasts for several years, contrasted with actual peak loads realized, before the impact of the changes in forecasting methodology can be fully assessed. The Public Staff believes that the current forecasts by NCEMC are reasonable for planning purposes.

EU

EU's 15-year forecast predicts that its winter peak, which is considered 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 1.2%. The average annual growth of the annual peak is 6 MW over the 15-year forecast. The Public Staff believes that the forecasts by EU are reasonable for planning purposes.

Haywood

Haywood's 15-year forecast predicts that its winter peak, which is considered its system peak, will grow at an average annual rate of 2.1%. Its energy sales are predicted to grow at an average annual rate of 2.0%. The average annual growth of the annual peak is 2 MW over the 15-year period. The Public Staff believes that the forecasts by Haywood are reasonable for planning purposes.

Piedmont

Piedmont's 15-year forecast predicts that its winter peak, which is considered its system peak, will grow at an average annual rate of 2.1%. The average annual growth of its summer peak is 3 MW over the 15-year period. Piedmont's energy sales are predicted to grow at an average annual rate of 2.1%. The Public Staff believes that the forecasts by Piedmont are reasonable for planning purposes.

Rutherford

Rutherford's 15-year forecast predicts that its winter peak, which is considered its system peak, will grow at an average annual rate of 1.4%. Its energy sales are predicted to grow at an average annual rate of 1.2%. The average annual growth of Rutherford's winter peak is 5 MW over the 15-year period. The Public Staff believes that the forecasts by Rutherford are reasonable for planning purposes.

Summary of Load Forecasts

The following table summarizes the growth rates for the electric utilities' system peaks and energy sales forecasts.

2011-2025 Growth Rates
(After EE and DSM)

	Summer Peak	Winter Peak	Energy Sales	Annual MW Growth
PEC	1.6%	1.8%	1.2%	213
Duke	1.6%	1.6%	1.8%	322
DNCP	1.7%	1.8%	1.8%	342
NCEMC	1.8%	1.7%	1.7%	58
EnergyUnited	1.0%	0.9%	1.2%	6
Haywood	2.2%	2.1%	2.0%	2
Piedmont	2.1%	2.1%	2.1%	3
Rutherford	1.4%	1.4%	1.2%	5

Reserve Margins

PEC

A capacity margin is calculated by dividing reserves by the total supply resources, while a reserve margin is calculated by dividing reserves by the system firm load after the impact of DSM. PEC stated that a minimum capacity margin target range of approximately 11%-13% satisfies the one day in ten year Loss of Load Expectation (LOLE) criterion and provides an adequate level of reliability. PEC further stated that it considers 11% to be the minimum and acceptable capacity margin in the near term, but that 12-13% is appropriate to be used in the longer term due to forecast uncertainty. The projected capacity margins range from 12% to 20% over the planning period. PEC stated that these capacity margin values are the equivalent of 14% to 25% reserve margins, which were validated by the Public Staff. This implies a reserve margin target of 14% to 15% over the long term planning period. As shown in PEC's IRP, projected reserve margins exceed this targeted level significantly during the planning period and particularly during the 2011 to 2014 period. While PEC's plan details the addition of 635 MW of generation (Richmond County) in 2011 and 920 MW of generation (Wayne County) in 2013, it does not provide for a corresponding rate of retirement of other facilities. PEC noted that additional resources cannot be brought online in the exact amount needed to match load growth.

Duke

Duke stated that its own historical experience has shown that a 17% target planning reserve margin is sufficient and necessary to provide reliable power supplies for its North and South Carolina service areas. Duke also stated that from July 2005 through July 2009, generating reserves never dropped below 450 MW, but noted that there are increased risks associated with reserve margins, which include (1) increasing age of units, (2) inclusion of a significant amount of renewable energy (which is generally less available than traditional supply side resources), (3) uncertainty related to increases in the Company's EE and DSM programs, (4) longer lead times for constructing base load units, (5) increasing environmental pressures, and (6) increases in derates of units due to hot weather and drought.

GENERAL ORDERS – ELECTRIC

DNCP

PJM conducts an annual reliability assessment to determine an adequate level of capacity in its footprint to meet the target level of reliability measured with a LOLE that is equivalent to one day of outage in ten years. PJM's 2009 assessment recommended using a reserve margin of 15.3% for the entire PJM footprint. DNCP uses the PJM reserve margin guidelines in conjunction with its own load forecast to determine its long-term need for capacity. The reserve margins for the first three years of the planning period are 16.1% (2011), 16.7% (2012), and 13% (2013). Because DNCP is only obligated to maintain a reserve margin for its portion of the PJM coincidental peak load, it used a coincidence factor of 96.3% to derive an effective reserve margin of 11% for 2014 through 2025.

DSM and EE

The Public Staff's review of the DSM/EE portions of the 2010 IRPs indicates that there is little difference from those filed in 2009. Duke, DNCP, NCEMC, and the independent EMCs, Haywood, Piedmont, Rutherford, and EU, generally forecast fewer DSM/EE resources (in terms of MW and megawatt-hours (MWh)) over the planning horizon. PEC indicated a small increase in its forecast of DSM resources. All of the electric utilities rely almost exclusively on the portfolio of DSM/EE programs they have designed and adopted over the last couple of years to meet their forecasted DSM/EE resources over the planning horizon, with only a few programs recently implemented or still under consideration.

Evaluation of Resource Options

PEC, Duke, and DNCP provided information describing their analysis and evaluation of resource options as required by Rule R8-60(i)(8). The IOUs use accepted production cost simulation models that have the ability to perform optimization analysis to select between different competing resource portfolios that potentially could be added in various combinations to satisfy the utility's future load requirements. The objective of these models is an identification of the least cost combination of resources as determined by an evaluation of the present value of revenue requirements for the various portfolios, while maintaining the target reserve margin. In addition to the review of the IOUs' load forecasts, future DSM and EE programs, and renewable resources, the Public Staff also reviewed forecasts of fuel prices, existing generation characteristics, and the projected capital costs associated with new generation facilities used in the resource optimization models. The investigation by the Public Staff indicates that the projected operating and capital costs used in the production models and the evaluation of resource options were conducted in a reasonable manner for purposes of this proceeding.

REPS Compliance Plan Review

G.S. 62-133.8 requires all electric power suppliers to provide specified percentages of their retail sales using renewable energy resources or reduced energy consumption through implementation of EE measures. Commission Rule R8-67(b) requires electric power suppliers to file a plan on or before September 1 of each year explaining how they will meet the requirements of G.S. 62-133.8(b), (c), (d), (e), and (f). The plans must cover the current year and the next two calendar years, or in this case 2010, 2011, and 2012.

Duke, PEC, and DNCP provided an assessment of alternative supply-side energy resources as part of their REPS compliance plans. All EMCs in North Carolina also provided plans.

The Public Staff noted that the electric power suppliers have had some difficulty obtaining sufficient resources from swine waste and poultry waste to meet the requirements of G.S. 62-133.8(e) and (f). The filings regarding the efforts of the electric power suppliers to meet these requirements are in Docket No. E-100, Sub 113.

Conclusions

Based upon the foregoing, the Commission finds 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 thus produced are reasonable for purposes of this proceeding and should be approved. The 2010 biennial IRP reports and 2010 REPS compliance plans submitted by the IOUs are reasonable and should be approved.

The Commission also finds that the 2010 biennial IRP reports and 2010 REPS compliance plans submitted by NCEMC, Piedmont, Rutherford, EU, Haywood, GreenCo, and Halifax are reasonable and should be approved.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 5

Least Cost Resource Portfolio Selection

In its comments, SACE stated that Duke modeled several resource portfolios in its IRP analysis. Some of these portfolios used a "High Energy Efficiency" or "High DSM" case, which includes the full target impacts of the save-a-watt bundle of programs for the first five years and then increases the load impacts at 1% of retail sales each subsequent year until the load impacts reach the economic potential identified by Duke's 2007 market potential study, i.e., a 13% decrease in retail sales. Duke did not select a portfolio with the High DSM case, however, despite the fact that the portfolios incorporating Duke's High DSM case cost less, have lower risk, and appear to result in lower average electricity rates than does the optimal plan. As a result, Duke's plan does not result in the least cost mix of resources.

SACE argued that, in contrast to Duke's failure to select an identified resource portfolio with a High EE case, PEC failed to even model a high efficiency case. In its IRP, PEC identifies three alternative resource plans that it considered for scenario analysis. However, PEC did not identify any scenario that included a portfolio with additional investments in EE (or renewable resources). Rather, these three alternative plans differed only in terms of the amount of gas-fired and nuclear capacity contained in each and in the timing for new additions of units with these technologies. SACE maintained that PEC's failure to model different levels of EE reveals a critical flaw in the Company's analysis. PEC did not conduct a similar sensitivity analysis even though the Commission's 2010 order called for "full and robust analyses and sensitivities."

In its reply comments, Duke stated that, as to the substantive aspects of Duke's IRP, SACE initially criticized the Company's portfolio analysis for not prioritizing its High DSM case in all of its portfolios. It noted that SACE alleged that the High DSM case, when applied to all of the Company's potential portfolios, is lower cost to customers, lower risk to customers, and will result in lower rates to customers than Duke's Optimal Plan, which is its selected portfolio of 2 Nuclear Units (2021/2023) and incorporates the Company's Base Case. SACE also included confidential Attachment 1 to demonstrate the comparison of certain High DSM case portfolios to the Optimal Plan portfolio on a net present value basis. Duke submitted that it is notable that SACE did not include the cost comparison information for the High DSM case as applied to the 2 Nuclear Units (2021/2023) timeframe in Attachment 1. Duke argued that SACE's comparison of the Company's High DSM sensitivity cases to its Base Case portfolios is misleading and presents an "apples to oranges" comparison. Duke argued further that, SACE's analysis disingenuously fails to acknowledge that the Company's 2 Nuclear Units (2021/2023) timeframe is the most cost-effective portfolio under the High DSM sensitivity.

Duke explained that it is unreasonable to compare the Company's model portfolios that incorporate Base Case impacts for EE and DSM with those portfolios that incorporate High DSM impacts. SACE's analysis is fundamentally flawed in that its analysis compares model portfolios with different load profiles and is useless for the purpose of making any meaningful comparisons for resource planning purposes. This rings true for comparisons of Clean Energy portfolios, High Fuel Cost portfolios, and any other sensitivity portfolios to Base Case portfolios. According to Duke, the basic fact underlying this assertion is that each of the model portfolios includes the same load, and the production simulation model will dispatch the model to meet that load with the selected resource mix. When sensitivities are applied to a certain aspect of the model portfolios, such as to EE and DSM impacts, fuel costs or load variations, it must be applied to each model portfolio so that the selected aspect of each portfolio will be impacted similarly and the production simulation model will run each portfolio under the same constraints.

Duke maintained that SACE conveniently failed to address that when Duke's model portfolios are properly compared to each other, such that each portfolio includes the High DSM sensitivity impacts, the portfolio with 2 Nuclear Units (2021/2023) is the least cost to customers on a net present value basis. SACE's Attachment 1 to its comments includes all of the other evaluated portfolios with the High DSM sensitivity except the 2 Nuclear Units (2021/2023). However, one need only look to Table A2 of the 2010 IRP to discover that the 2 Nuclear Units (2021/2023) is $1.6 billion lower in cost on a net present value basis than the Natural Gas portfolio under the High DSM sensitivity. Applying that information to the chart set forth in Attachment 1, which includes the Natural Gas portfolio, clearly demonstrates the cost-effectiveness of the 2 Nuclear Units (2021/2023) portfolio as compared to the other portfolios under the High DSM sensitivity. Duke concluded that, even under SACE's misleading analysis, one can still objectively understand that the selected portfolio within Duke's 2010 IRP supports the development of a clean, reliable and cost-effective resource plan to meet its customer's need over the planning horizon.

According to PEC in its proposed order, its comprehensive analysis of achievable energy efficiency potential was described in the rebuttal testimony of PEC witness Chris Edge in Docket No. E-100, Sub 124. He stated that PEC contracted with ICF International, an industry leader in the design, implementation, market assessment and evaluation of DSM and EE programs, to perform a comprehensive analysis of the cost-effective, achievable potential across PEC's service territory. Mr. Edge testified that the ICF study considered the PEC-specific factors that impact potential savings from utility administered DSM and EE programs including: demographic and customer composition; PEC electric rates and avoided costs; known regulatory factors (i.e., the significant effect of customer opt-out provisions); and other assumptions specific to PEC's service territory. Mr. Edge explained that the study was intended to identify the approximate amount of cost-effective savings that can realistically be achieved through utility DSM and EE programs within the PEC service area over an extended period of time (and under a stated set of assumptions). He further explained that it serves as the foundation for identifying general areas and programs that might warrant consideration in PEC's DSM and EE portfolio. PEC argued that the DSM and EE potential a utility should incorporate into its least cost resource plan should be based upon a specific set of conditions that are unique to the utility's service territory to facilitate the most accurate comparisons with alternative solutions and that the methodology for deriving demand-side reductions for resource planning purposes should be based on a detailed, investment grade analysis of achievable, cost-effective options, versus a generic, hypothetical comparative analysis.

Evaluation of EE

According to SACE, EE is the least-cost system resource. Unlike supply-side resources, EE, even at aggressive levels, reduces customer utility bills. Energy efficiency also moderates rate increases by reducing or delaying the need for new generating capacity. In fact, states with leading EE programs often have electricity rates that are comparable to, or even lower than, North Carolina.[1] In addition to lower customer bills and rate moderation, the numerous benefits of EE include environmental quality improvements, water conservation, energy market price reductions, lower portfolio risk, economic development and job growth, and assistance for low-income populations.[2]

SACE argued in its comments that, despite these benefits, Duke and PEC significantly underestimate the potential EE savings in their IRPs. The utilities failed to consider efficiency resources on an equivalent basis as supply-side resources, and therefore, their IRPs do not result in the least-cost mix of resource options. Together, PEC and Duke forecast cumulative energy savings of 5.2 percent of retail sales over the next fifteen years.

SACE stated that Duke limits its program potential to the economic potential identified by its 2007 market potential study. Duke witness Richard Stevie testified in the proceeding on

[1] John D. Wilson, Energy Efficiency Program Impacts and Policies in the Southeast (May 2009) at 4, http://www.cleanenergy.org/images/files/SACE_Energy_Efficiency_Southeast_May_20091.pdf.

[2] See, e.g., Marilyn A. Brown et al., Energy Efficiency in the South, Southeast Energy Efficiency Alliance (April, 12, 2010), http://www.seealliance.org/se_efficiency_study/full_report_efficiency_in_the_south.pdf.

the 2008 and 2009 IRPs, however, that this study is out of date and that Duke is continuing to look at additional programs that were not analyzed in the potential study. PEC limits its program potential to the cost-effective, realistically achievable potential in its updated potential study. While the scope of PEC's updated study does appear to be broader than the earlier version, it appears to suffer from the same fundamental shortcomings as the earlier study. For example:

- PEC's potential study mentions that the findings were benchmarked against other utilities, but such benchmarking, if it has been done, has not been disclosed.
- Energy savings practices, measures and entire sectors remain excluded from the scope of study.
- It is not evident from the resource plan that PEC has yet made effective use of the insights offered by its consultant in the potential study. It does not appear that PEC has adopted some highly cost-effective programs and strategies included in PEC's market potential study, such as an ENERGY STAR Appliance program and certain non-residential incentive programs.

Further, SACE argued that PEC effectively assumes no further technological progress or development of new energy-saving practices. Duke is more confident about advances in efficiency, although this confidence is not fully reflected in its long-term resource plans.

SACE alleged that PEC and Duke primarily evaluate renewable energy resources in the context of minimum compliance with the REPS. Renewable energy potential is barely varied among the strategies considered in the 2010 resource plans proposed by Duke and PEC. One exception to this limited perspective is that both utility plans discuss offshore wind development, which is likely to require more than a decade to develop. SACE noted that North Carolina's utilities are prudently evaluating this resource in order to determine the appropriate development path in light of its resource characteristics and forecast system resource needs.

Additionally, SACE maintained that Duke and PEC should conduct an analysis of the potential ancillary benefits or costs of integrating significant levels of on-system renewable energy resources, including:

- The potential benefits regarding grid stability;
- The potential efficiency gains in transmission and distribution associated with higher levels of distributed generation; and
- The reduced costs associated with greenhouse gas and air pollutant mitigation.

SACE stated that Duke and PEC assume that the benefit of renewable energy resources is limited to about 5 - 7 cents per kWh (avoided costs), which seems to be an underestimate. Moreover, these utilities spend about twice this amount to build and operate baseload, intermediate or peak power plants.

According to NC WARN, EE will play a significant role in North Carolina's energy future. In its April 29, 2010 presentation to the Energy Policy Council (EPC), the American Council for an Energy-Efficient Economy (ACEEE) presented an EE market potential study that demonstrated that an annual electricity savings of 1.2 - 1.6% is achievable over the next decade. Energy savings in the 24 - 32% range were shown to be achievable in North Carolina by 2025. Several other studies that have been presented to the Commission in recent years have shown similar potential savings. Given these savings, it is apparent from the IRPs that Duke and PEC incorporated into their IRPs only the minimal amount of EE required under the REPS, rather than what was practical. Last year NC WARN argued that the IRPs do not reflect customers who would adopt the EE measure regardless of any utility-sponsored EE program.

In its reply comments, PEC argued that NC WARN frequently comments on energy savings when discussing EE, without any real recognition of peak demand impact, implying that a 1% energy savings translates to 1% demand savings. This is a significantly flawed assumption. For example, NC WARN claims significant energy savings are realized through the replacement of incandescent light bulbs with compact fluorescents. While true that such actions produce energy savings, they have a negligible impact on summer peak demand which occurs late in the afternoon when lighting usage is insignificant.

PEC noted that SACE argued that PEC's long-term EE provisions lag significantly behind the "typical leading utility." SACE suggests that PEC should modify its IRP EE forecasts based on the arbitrary, aspirational goals of other utilities. In fact, SACE attempted to provide a comparative analysis of PEC and Duke with that of a generic "leading" utility. PEC offered that, as this is a fictional utility, SACE is unable to provide details as to where the utility is located, the composition of its customer base and its end-use load, the utility's rates, its avoided costs, etc. (all of which play a huge role in determining what DSM and EE programs it can cost-effectively offer). SACE then somehow determined the EE potential of this generic utility without any economic, technical, or market analysis. PEC then stated that, without any such supporting information, SACE concluded that PEC has significantly underestimated the potential EE savings in its IRPs and that "... Duke and PEC lag significantly behind the typical leading utility."

PEC noted that SACE also alleged that neither Duke nor PEC is using a comprehensive EE potential study in its IRP process. Regarding PEC, SACE stated: "PEC limits its program potential to the cost-effective, realistically achievable potential." PEC responded that it should only offer cost-effective, achievable DSM and EE programs. DSM and EE account for over 1,700 MW of load reduction in PEC's IRP. These projected impacts play a substantial role in PEC's ability to meet the future reliability needs of its customers. They must be real and achievable or the reliability of PEC's system will be impaired. Cost-effective, realistically achievable potential is the most prudent standard for resource planning purposes, versus a hypothetical potential derived from speculative, unsupported assumptions.

Duke argued that its projections relating to EE savings are not tied in any way to its REPS obligations. At present, the Company is statutorily limited to meeting up to 25% of its general REPS obligations under G.S. 62-133.8(b)(2)c through EE savings.[1] The Company's portfolio of programs are projected to achieve significantly more than 25% of the Company's general REPS requirements on an annual basis through the term of its 2010 REPS compliance plan. Under its REPS compliance plan, Duke stated that it intends to utilize EE to the fullest extent possible, accounting for 25% of the compliance requirement beginning in 2012, but this is not a limiting factor on the amount of EE the Company will be actively promoting. The Company's modified save-a-watt model, approved in the Commission's Order Approving Agreement and Joint Stipulation of Settlement Subject to Certain Commission-Required Modifications and Decisions on Contested Issues issued February 9, 2010, in Docket No. E-7, Sub 831, incentivizes it to attempt to achieve all cost-effective EE over the course of the pilot in order to achieve its stated savings targets.

Duke further added that, during the same meeting in which ACEEE presented its potential study to the EPC, Duke and PEC made a joint presentation which identified specific significant deficiencies in the ACEEE study. These deficiencies include:

- A lack of any adjustment for large customer statutory opt-out of utility EE and demand-side management programs, as permitted under G.S. 62-133.9;
- A lack of any adjustment for naturally occurring, customer-driven EE captured in the company load forecasts;
- Assumptions of unreasonably high participation rates that are not reflective of the current data for the utilities;
- Reliance on market potential studies completed before the passage of the Energy Independence and Security Act of 2007;
- A lack of any discussion of equipment life (also referred to as Rate of Turnover); and
- The inclusion of below efficiency standard impacts already captured in the utilities' load forecasts, thereby double-counting potential savings impacts.

Duke noted that SACE focused its criticism of the Company based on its comparison to what it deems a leading utility can achieve and alleged that Duke continues to underestimate its EE potential in its IRP. SACE also blamed the industrial opt-out provision of G.S. 62-133.9(f) for lost EE savings opportunities and criticized Duke for failing to perform a new market potential study for its IRP.

Duke argued that, like NC WARN, SACE relied upon ACEEE data to support its market potential assessment and overlooked other current, region-specific, information that informs reasonable expectations with respect to the realistic market potential for EE in Duke's service territory. The 2009 EPRI study estimated the economic potential for the Southern region to be

[1] In 2021, when the REPS obligation increases to 12.5%, this limitation on the use of EE savings increases to 40%.

4.4% over 10 years, not the 7.2% to 13.6% cited by SACE in reliance upon ACEEE's analysis. Also, due to the lower than average electric rates and monthly bills that Duke's customer enjoy, some EE programs that work well in other markets may not be as attractive to customers or even cost effective. According to Duke, the ultimate driver of EE savings achievement is customer participation and choice. The Company is striving to achieve its High DSM case, which exceeds the estimated EE market potential developed by EPRI, but cannot assume it is going to happen without a track record of real results. For purposes of the 2010 IRP, the Company's Base Case for EE/DSM achievements represents a more reasonable and prudent input to the resource portfolio.

Baseload Requirements

NC WARN offered that, while there is no North Carolina definition of a baseload power plant, the Commission requires the electric utilities to file monthly Base Load Power Plant Performance Reports pursuant to Rule R8-53.[1] That rule requires reports on plant outages and generation capacity on each plant in the utility's nuclear fleet and listed coal plants, as well as all generating plants with greater than 500 MW maximum dependable capacity (MDC) utilizing coal or nuclear fuel. The 500 MW capacity limit clearly distinguishes between the baseload units that can be operated most of the time and the peaking units that are operated only when required. According to NC WARN, a useful distinction between the two resource types is that baseload units take time, up to days, to ramp up to full operation while peaking units, such as the natural gas combustion turbines (CT), can generate electricity in a far shorter period of time after being dispatched.

NC WARN explained that another way to view baseload is to include generating units that operate a certain percentage of the year, with rule-of-thumb estimates ranging from 35% up to 65% or more.[2] The U.S. Department of Energy, in its regulation, 10 C.F.R. 500.2, defines a baseload power plant as a power plant, the electrical generation of which in kilowatt-hours exceeds, for any 12-calendar-month period, such power plant's design capacity multiplied by 3,500 hours. This includes plants that operate for more than 40% of the year (3,500 hours divided by 8,760 hours in a year). In order to reduce the costs of operating peak plants, the baseload plants should be operated at peak times.

NC WARN noted that in its February 2, 2011 Base Load Power Plant Performance Report filing in Docket E-7, Sub 935, Duke reported that it currently has 11,854 MW in baseload units.[3] These include the nuclear units, Oconee 1, 2 and 3; McGuire 1 and 2; and Catawba 1 and

[1] Duke currently is filing those reports in Docket E-7, Sub 935 and PEC in Docket E-2, Sub 971.

[2] NC WARN argued that, with increasing reliance on renewable energy sources, both the 500 MW definition and the 40% percentage definition may not hold up as combinations of solar and wind installations function as the equivalent to baseload. See Blackburn, "Matching Utility Loads with Solar and Wind Power in North Carolina: Dealing with Intermittent Electricity Sources;" Institute for Energy and Environmental Research, March 2010. www.ieer.org/reports/NC-Wind-Solar.html.

[3] In its Base Load Power Plant Performance Report, Duke included Marshall 1 and 2, each having an MDC of 380 MW. These plants are operated primarily as baseload units and are included in the Duke totals used herein.

2; and the coal units, Belews Creek 1 and 2; Marshall 1, 2, 3, and 4; and Cliffside 5. The addition of Cliffside 6, scheduled to begin operation in 2012, brings Duke's total to 12,679 MW. In its January 27, 2011 filing in Docket E-2, Sub 971, PEC reported that it currently has 6,359 MW in baseload units, including the nuclear units, Brunswick 1 and 2, Harris 1 and Robinson 2, and the coal units, Mayo 1 and Roxboro 2, 3, and 4.

According to NC WARN, these total baseload capacity figures are useful in looking at the load duration curves submitted in each of the IRPs. A load duration curve places the MW load on the system for each of the 8760 hours in the year and the resulting curve shows the annual range of load from the lowest load needed for an autumn night, as an example, to the highest peak on a summer afternoon.

NC WARN stated that Duke provided two load duration curves in its IRP, Figure 3.1 (without EE) on page 54, and Figure 3.2 (with EE) on page 57. The load range for 2010 is 4500 MW at the lowest end and almost 17,000 MW at the upper end, with the average 2010 hourly demand approximately 10,900 MW. NC WARN argued that an important factor emerges from reviewing Duke's load duration curves. When all of its baseload plants are in operation (12,679 MW), they provide more electricity than is needed for 87% of the hours in a year; in other words, not all of the existing baseload units can operate for most of the year. For most of the year, the plants are either shut down and idle or spinning (still operating but not connected to the grid).[1]

NC WARN explained that, in its load duration curves, Duke then forecasts increases in load for each of the hours for 2015, 2020 and 2025.[2] Even using the load duration curve without EE, Duke still has excessive baseload through 2025; with Duke's projected EE programs, the current baseload plants provide excessive load for more than 50% of the year. With additional EE measures or combined renewable energy sources, less and less baseload will be needed.

NC WARN stated that, from its twelve-month summary in its January 27, 2011 filing in Docket E-2, Sub 971, PEC shows a total of 6,359 MW for its 500 MW-plus baseload units. In its IRP, at pages B-1 through B-4, PEC designated 7,373 MW as baseload resource type by including several smaller coal plants, Asheville 1 and 2, Robinson 1, in its baseload total. PEC's load forecast curves in its IRP, pages 26-28, show that for approximately 60% of the hours in the year 2010, not all of the designated baseload plants were required to meet its load.

According to NC WARN, in the IRPs, the utilities continue to show a need for baseload additions in their North and South Carolina jurisdictions. In its IRP, page 81, Duke is proposing two units at the Lee Nuclear Station in Gaffney, South Carolina, forecasted to be in operation in 2021 and 2023. Taking a more realistic approach, PEC advanced three scenarios in its IRP. While it has apparently backed away from its proposal to build new reactors at the Shearon Harris site, it still continues to include new baseload units in two of its three scenarios. PEC's

[1] Duke also uses baseload power as part of its pumped storage facilities, pumping water to an upper reservoir to release in peak periods. Duke includes a portion of these baseload plants as part of its reserve margin.

[2] NC WARN noted that the load duration curves show a substantially greater increase in growth for the hours requiring the lowest load than for peak hours.

preferred scenario, Plan A, proposes two jointly owned nuclear plants with it owning approximately 25% share of each plant. Plan B is a much more prudent approach assuming a fairly aggressive control of carbon dioxide. It contains no nuclear units, and the difference in generation consists of natural gas-fired combined cycle (CC) plants. Lastly NC WARN stated that Plan C shows two units at the Shearon Harris site in Wake County, but is highly unlikely as the scenario assumes, among other things, low nuclear construction costs.

In response, PEC stated that NC WARN's comments are based upon several incorrect assumptions. The first such assumption is that baseload generation is any supply-side resource with a capacity factor greater than 40%. Using this definition, NC WARN then creates a load duration curve that purports to support its claim that PEC and Duke have excess baseload generation. NC WARN's baseload definition sweeps in many intermediate load-following plants, including CC and intermediate coal plants. PEC's baseload coal plants are described in the testimony of PEC witness Dewey Roberts in Docket No. E-2, Sub 976. He stated that these plants have capacity factors of over 70%. Mr. Roberts also testified that PEC's baseload nuclear plants had capacity factors of over 91%. Finally, Mr. Roberts explained that even PEC's intermediate load following plants have capacity factors in excess of 50%. Thus, NC WARN's unique definition of baseload is so broad as to include all of PEC's plants except its simple cycle CT peaking units.

Importantly, according to PEC, resource planning does not hinge on administrative definitions of baseload, intermediate, or peaker. Instead, PEC's resource planning considers the load and energy needs of its customers, then models the dispatch of existing resources to meet these load and energy requirements, including necessary reserves, and identifies additional resources needed to reliably meet the remaining energy and load at lowest reasonable cost. The timing and characteristics of future capacity needs are determined by sophisticated industry-accepted modeling. NC WARN appears to be trying to define the capacity factor of baseload as low as 40% to include wind and solar as baseload. However, neither can achieve even that level of operation. Solar has, at best, a 25% capacity factor, while wind can generally achieve no greater than a 35% capacity factor.

PEC explained that, furthermore, wind and solar are each more expensive than PEC's current net asset value on a $/kW basis, and since PEC would have to add 2 MW of wind and solar generation to equal 1 MW of replaced capacity, the net effect for PEC would be at least a doubling of its capital costs. Further, the REPS structure recognizes that the cost of wind and solar each exceed avoided cost as demonstrated by actual contracts to date. Therefore, even considering that wind and solar provide free energy, a combination of the capital costs of wind and solar would far exceed avoided cost, without even taking into account the embedded cost of the generation to be shut down. NC WARN's approach overlooks the many important considerations in resource planning, including availability, reliability, dispatchability and overall cost of the resource mix.

In its reply comments, Duke stated that NC WARN's arguments are primarily based on a pessimistic view of load growth in the Company's service territory, its application of two outdated planning concepts, and several fundamental errors. NC WARN devoted four pages of comments to an argument that Duke already has excessive amounts of baseload capacity. NC

WARN stated that, "[w]hen all of its baseload plants are in operation (12,679 MW) they provide more electricity than is needed for 87% of the hours in a year." NC WARN's 87% calculation results from determining the point where the 2010 Duke load duration curve, presented on pages 54 and 57 of the 2010 IRP, meets the 12,679 MW level.

Duke maintained that NC WARN's calculations and conclusion regarding Duke's alleged lack of need for baseload capacity are plainly wrong. First, NC WARN grossly miscalculated the Company's actual baseload capacity available to serve its customers. NC WARN's calculation included the full Cliffside Unit 6 capacity (825 MW), which was not available in 2010, and also included the entire capacity of Catawba Nuclear Station, of which Duke only owns 19.26%. Because the load duration curve in the 2010 IRP excluded that portion of the Catawba Owner's load for which Duke has no obligation to serve, the capacity calculation must also exclude the 1,109 MW portion of Catawba that is not retained by Duke. Correcting these two errors would remove 1,934 MW, reducing the 12,679 MW figure used by NC WARN to 10,745 MW. Instead of 87%, the corrected crossing point should result in a figure closer to 60%.

Duke argued that the use of load duration curves as a planning methodology has long been recognized as inaccurate and inadequate for determining optimal capacity mix for a generation system. The inaccuracy of this methodology is clearly illustrated through a simple examination of Duke's actual generation records for 2010. As a group, Duke's fourteen units that operate as baseload capacity for the system were in reserve shutdown (available, but shut down or idle) for 4,512 hours out of a total of 122,640 hours (14 x 8760) during the year. That represents 3.68% of the hours over an entire year when those baseload units were available, but not generating electricity for Duke's customers. When the actual data is compared to NC WARN's 87% miscalculation, as well as its patently false statement that "[f]or most of the year, the plants are either shut down and idle or spinning (still operating but not connected to the grid)," it is clear that NC WARN does not understand the facts that underpin the Company's resource planning and utilizes flawed methodology to criticize the Company's resource plan. Duke argued that these flawed conclusions presented by NC WARN are exactly why modern planning tools have replaced the use of load duration curves in determining an optimal capacity mix for resource planning purposes.

Cost of Additional Nuclear Generation

NC WARN argued that, regardless of the Commission's views on the risks and benefits from nuclear baseload units, the projected costs of this source of electricity have risen exponentially to the point they simply cannot be considered in the least cost mix. The cost of each new nuclear unit nationally is now in the $10 - 12 billion range, and very few are actively being considered.[1]

NC WARN reasoned that the IRPs, as filed with the Commission, contain little justification for the costs of the proposed nuclear units and even less discussion about the risks associated with proceeding with these large-scale projects. If the utilities continue to go ahead with the proposed plants, electricity bills will increase considerably over the next decade (or

[1] See, e.g., Wald, "New Nuclear Plant Projects Stalled by Market Forces," February 8, 2011.

longer, given likely construction delays). These large nuclear units, each more than 1050 MW, would require large reserve capacity in case they are out of operation, increasing the costs even more. The construction and operation of these new nuclear plants are risky in terms of the costs to the ratepayers and taxpayers, as well to the overall economy of North Carolina. The risk is evident in that none of the current nuclear proposals are funded by financial institutions, i.e., Wall Street, and only a limited number of direct incentives, such as loan guarantees, have been made available from taxpayer-funded federal government programs.

NC WARN explained that, while nuclear costs are projected to continue to rise, the costs of renewable energy have consistently decreased. In his July 2010 paper, Dr. John O. Blackburn reviewed the costs of solar energy and nuclear power plants and determined that in 2010 solar energy has finally become less expensive than nuclear energy.[1] The study included all subsidies for both technologies and compared the cost per kWh generated by each. An important consideration in the Commission's review of the IRPs is that the cost of solar energy and other renewable energy sources is expected to continue to decrease while projected costs of nuclear power plants have risen steadily for the past decade and are expected to increase even more over time.

NC WARN argued that Dr. Blackburn's finding is confirmed in depth by the U.S. Energy Information Administration (EIA). The EIA, in its most recent Annual Energy Outlook, AEO2011, determined that the updated overnight capital cost estimates for nuclear power plants were 37% above those in the AEO2010, while photovoltaic technologies dropped by 25% in the same year. Using the definition of "overnight capital cost" from the World Nuclear Association, a supporter of nuclear energy worldwide,

> Capital costs comprise several things: the bare plant cost (usually identified as engineering-procurement-construction - EPC - cost), the owner's costs (land, cooling infrastructure, administration and associated buildings, site works, switchyards, project management, licenses, etc), cost escalation and inflation. Owner's costs may include transmission infrastructure. The term "overnight capital cost" is often used, meaning EPC plus owners' costs and excluding financing, escalation due to increased material and labor costs, and inflation.

NC WARN noted that the last items of financing, increased material and labor costs, and inflation are the components that raise the projected costs of nuclear power dramatically, and particularly if construction does not stay on schedule.

According to SACE, neither Duke nor PEC has provided, either in its IRP or in response to a data request, any supporting evidence or documents that form the basis for the nuclear cost estimate. There are a number of factors for the great uncertainty regarding the ultimate construction cost of Duke's proposed Lee Nuclear Station or any new nuclear power plants in the region.

[1] Blackburn and Cunningham, "Solar and Nuclear Costs – The Historic Crossover: Solar Energy is Now the Better Buy," July 2010. Available at www.ncwarn.org/?p=2290.

PEC observed that, continuing with its attack on new nuclear generation, NC WARN stated, "These large nuclear units, each more than 1,050 MW, would require large reserve capacity in case they are out of operation, increasing the costs even more." PEC argued that NC WARN offered no support for this statement because it is unsupportable. These units require no more reserves than PEC's other units that are nearly 1,000 MW in size.

PEC continued, noting that NC WARN next suggested a cents/kWh comparison between EE and supply options. This is another example of a one-dimensional comparison of "apples and oranges" that may appear to support NC WARN's premise, but is meaningless and unsupportable in the context of an IRP proceeding. A CT, for instance, may cost 30 cents per kWh because it does not generate much electricity, but that does not mean PEC would never select it as the least cost resource. The only meaningful comparison for cost to customers is the final rates they pay (or as a proxy, revenue requirements when only supply-side resources are considered) based upon the total least cost resource mix proposed, including total system fuel impacts. In addition, the amount of EE reasonably and economically available must also be considered in this analysis.

PEC noted that SACE asserted that PEC did not consider nuclear construction cost uncertainty in its analysis. In response, PEC referred SACE to Appendix A of PEC's 2010 IRP, in which PEC presented sensitivities (see page A-4) that were +/- 30%; and to page A-7, where PEC used the +30% figure for 2 of the 3 scenarios. Importantly, PEC's IRP does not include the construction of a new nuclear unit. The only new nuclear generation is the potential participation in a regional project, and PEC would have to obtain Commission approval prior to participating in such a project.

According to Duke, NC WARN continues to make the assertion that the projected costs of new nuclear resources "have risen exponentially to the point they simply cannot be considered in the least cost mix." The Company's analysis of its own proprietary and the publicly available information indicates otherwise. Duke's most recent projection of the overnight cost of building two twin AP1000 units at the proposed Lee Nuclear Station site in Cherokee County, SC, is $11 billion, in 2010 dollars, exclusive of financing costs and exclusive of the impacts of inflation. This estimate was developed for Duke by Westinghouse Electric Company, LLC, and its consortium partner Shaw, Stone and Webster, Inc. (collectively WEC/SN). WEC/SN Engineering, Procurement & Construction (EPC) consortium is the EPC contractor for the two other AP1000 projects in the United States, Southern Company's Vogtle Nuclear Plant (Vogtle) and South Carolina Electric & Gas's (SCE&G) V.C. Summer Nuclear Plant (Summer), and is similarly involved in the construction of the AP1000 units in China. There are currently four AP1000 units under construction in China, and both Vogtle and Summer are ahead of Duke's Lee Nuclear Station in both licensing and construction. Duke has been following all of this activity closely, and early experience suggests that the construction work is going well as the AP1000 projects remain within schedule and budget and are moving forward as expected. On October 21, 2010, SCE&G, at an allowable ex-parte briefing, provided an update to the Public Service Commission of South Carolina (PSCSC) on the construction of the Summer Nuclear Plant. At that update, Steve Byrne, SCE&G Chief Generation Officer, told the Commission that the Summer project was moving forward as expected and that SCE&G had just completed negotiations with WEC/SN to move additional costs from the target category to the firm/fixed category. According to Mr. Byrne, approximately two-thirds of the Summer plant cost is now in the firm/fixed category. Additionally, Mr. Byrne explained that due to lower escalation rates, the new project cost projections were reduced by approximately $1 billion to $9.6 billion versus the initial estimate of $10.6 billion.[1] Additionally, SCE&G's most recently filed quarterly report, filed on February 14, 2011, in Docket No. 2008-196-E pursuant to PSCSC Order No. 2009-104(A), indicates that it is on track to complete the two units at Summer on its scheduled completion dates within the original construction cost forecast.

Duke explained that additionally, the new nuclear licensing process, involving the Nuclear Regulatory Commission's (NRC) issuance of the combined construction and operating license (COL) for the Vogtle, Summer and Lee Nuclear Station projects, will also help with the cost certainty on new nuclear projects. By the time the Lee Nuclear Station project is ready to start construction, the NRC will have reached its decision regarding the approval of the AP1000 design, and engineering and design for the AP1000 will be close to 100% complete, thereby bringing greater certainty to construction plans.

Duke recognized that the cost estimates used in its planning models are very important, and as such Duke stated that it continues to monitor all available projects and industry data to ensure that its estimates are in line with recent experience and based on the best available information at that time. Duke further stated that it believes that all recent experience in China and at the two plants in the Southeast, as well as the recent trend in industry data of lower escalation rates, supports the current level of its cost estimates used for resource planning purposes. Additionally, Duke noted that it models various project risks specifically relating to increases in capital cost and incorporates such analysis into the IRP through the +20%/-10% Nuclear Capital Cost Sensitivity used in its IRP analysis.

Duke noted that SACE, like NC WARN, also questioned Duke assumptions regarding the cost and schedule for construction of a new nuclear generating facility. SACE pointed to the history of the initial nuclear build-up in the United States and certain isolated examples of current projects developing different technologies to assert that the Company's estimates are inaccurate. As articulated above in response to NC WARN's comments, Duke stated that it believes that its current estimates for the schedule and cost of the proposed Lee Nuclear Station are reasonable and based upon the best information available at this time from the appropriate industry sources.

With respect to the schedule, Duke stated that it is important to include a full description of the construction window as well as the window for start-up and fuel load. The Lee Nuclear Station schedule currently shows deployment to the site for construction in the summer of 2014 for two years of initial site construction activities. At the end of construction is a six month window for fuel load and initial start-up testing. When defining the construction window from site deployment to commercial operation, the Lee Nuclear schedule represents an overall construction schedule duration approaching seven years for Unit 1. Duke believes this is a very realistic schedule given:

[1] The transcript of the SCE&G briefing is available on the PSCSC's website at the following web address: http://www.psc.sc.gov/exparte/epb-2010-10-21/epb-20101021 Transcript Presentation Materials.pdf.

- The AP1000 design and engineering will be substantially completed before construction starts;
- A stable NRC licensing platform avoids introduction of new requirements;
- The AP1000 design includes a simplified nuclear island design with passive safety features;
- Advanced modular construction techniques are currently being proven during construction of AP1000 reactors in China, and additional construction technique evaluation for the AP1000 in the United States will occur before the construction of Lee Nuclear Station begins;
- The extensive use of proven Pressurized Water Reactor (PWR) technologies; and
- The significant level of planning in coordination with the WEC/SN consortium that has gone into developing the current schedule.

According to Duke, a key consideration in Duke's selection of the AP1000 design was its simple passive design features and extensive use of proven PWR technologies. The passive design and use of proven technologies are strong mitigants to the asserted risks. The Company's approach is consistent with recently issued guidance from the Institute for Nuclear Power Operations (INPO), which states that "[m]odular design and construction, done correctly, can significantly reduce both overall construction cost and time. The decision to use modular construction techniques should be made at the very beginning of a project and factored into the overall design and constructability reviews. The use of modular construction can generally reduce the overall weight of steel by 20 to 40 percent."[1] Additionally, despite SACE's speculative remarks to the contrary, supply chain capacity has continued to expand while demand has reduced since the economic downturn of 2008.

Duke asserted that the NRC has recently affirmed the design certification schedule for the AP1000, which will lead to its certification of the AP1000 design, in its current revised design, in September 2011. The AP1000 reference COL for Vogtle is expected to be issued within months of the NRC certification of the AP1000 revised design. Duke stated that it continues to diligently monitor lead times for critical plant equipment, licensing activities and construction operations at all AP1000 design facilities both in the U.S. and abroad to stay current on the best available relevant information relating to the future construction of the Lee Nuclear Station. Based on its internal analysis and relevant industry information, Duke stated that it firmly believes that its current schedule for the proposed construction of Lee Nuclear Station is reasonable and prudent.

[1] INPO 11-001, February 2011, INPO/Utility Benchmarking Current Domestic Modular Construction Facilities.

Greenhouse Gas Emissions

According to SACE in its comments, Duke acknowledged the risk that federal regulation will require reductions of GHG emissions. However, Duke did not present any evidence in its 2010 IRP that it has a realistic plan for reducing its GHG emissions during the planning period.

SACE stated that Duke recognized that it is likely that Congress will adopt mandatory GHG emission legislation at some point, although the timing and details are highly uncertain at this time. Duke also recognized that the Environmental Protection Agency (EPA) is undertaking actions to regulate emissions of GHG from new and modified major stationary sources, including power plants. Moreover, the air quality permit for the new Cliffside Steam Station Unit 6 requires that Duke retire Cliffside Units 1-4, plus an additional 800 MW of coal-fired units located in North Carolina by the end of 2018. In addition, the air permit requires the company to take additional actions to render Cliffside Unit 6 carbon neutral by 2018, subject to Commission approval and "appropriate cost recovery." Nonetheless, Duke currently projects that its system carbon dioxide (CO_2) emissions will increase between 2010 and 2030, whether it adds new nuclear units or just new natural gas-fired units.

SACE explained that it is not surprising that Duke is projecting that its annual CO_2 emissions will rise between 2010 and 2030. Even though Duke is planning to retire more than 1,600 MW of existing coal capacity, emissions reductions from those retirements will be more than offset by increased emissions from the new Cliffside Unit 6 coal plant. Cliffside Unit 6 will emit approximately six million tons of CO_2 each year, or more than two million tons of CO_2 per year more than the 2008 CO_2 emissions from all of the coal units that Duke proposes to retire. In addition, Duke is planning to add more than 4,000 MW of new gas-fired CC and CT capacity over the planning period. Although they emit significantly less per MWh than coal-fired facilities, gas-fired units do emit CO_2.

SACE noted that, like Duke, PEC recognized that it is likely that Congress will adopt mandatory GHG emission legislation at some point and that EPA is undertaking actions to regulate emissions of GHG from power plants. Despite this acknowledgment, PEC provided no evidence in its 2010 IRP that its proposed resource plan (or the two alternatives it considered) actually will result in any, let alone significant, reductions in the GHG emissions from the Company's generation fleet. Unlike Duke, PEC did not even include a figure in its IRP showing the trajectory of future annual CO_2 emissions under its proposed and alternative resource plans.

SACE observed that PEC is proposing to retire 1,500 MW of its existing coal-fired units and to replace those retired units with 1,500 MW of state-of-the-art gas-fired generation. Although natural gas-fired generation emits only about 60 percent as much CO_2 per MWh as coal-fired units, the new state-of-the-art gas units being added by PEC can be expected to operate more often than the coal units slated for retirement have operated in recent years, especially given projected low natural gas prices. This means that it is possible that the Company's replacement of existing coal by new gas CC units may not result in any significant reduction in PEC's system CO_2 emissions. At the same time, the Company's proposed resource plan will add thousands of MW of additional CC and CT capacity during the 2010 to 2030 planning period.

SACE argued that, as a result, it is reasonable to expect that the Company's annual system CO_2 emissions will not go down much, if at all, during the planning period.

In its reply comments, PEC responded that, while SACE claimed neither Duke nor PEC has shown in its 2010 IRP that it has a realistic plan for reducing GHG emissions, this is incorrect. Appendix A to PEC's 2010 IRP explicitly shows that PEC considered the potential impact of carbon regulation in performing its scenario analyses. Implicit in the high and low carbon regulation scenarios is the reduction of GHG emissions.

Regarding natural gas-fired generation, PEC stated that it is retiring 1,500 MW of coal generation and replacing it with new natural gas-fired generation. PEC noted that SACE did not object to PEC being awarded the certificates of public convenience and necessity to construct the new natural gas-fired generation, and supports PEC retiring the coal generation. Yet now, SACE in this proceeding argued that even though natural gas-fired generation emits only about 60 percent as much CO_2 per MWh as coal-fired units, PEC can be expected to operate the new natural gas-fired generation more often than the coal units it is replacing and, therefore, emit the same amount of greenhouse gases. PEC reasoned that one must first wonder, if a utility is not to use nuclear, coal, or natural gas, how can it possibly be expected to meet the electricity needs of its customers? But more to the point, in the certificate proceedings in which the Commission approved PEC constructing the new Wayne County and Sutton natural gas facilities, one of the key cost justifications was these new units would allow PEC to better comply with new or future GHG emissions requirements due to their reduced emissions.

According to Duke in its reply comments, SACE further criticized Duke for allegedly failing to have a realistic plan to reduce GHG emissions over the planning horizon and for failing to evaluate the economics of the continued operation of its coal generating facilities with environmental controls already installed. The Company disputed this contention. Duke's IRP has been designed and modeled to provide affordable, reliable, and clean resources to meet future customer needs in a carbon-constrained environment. From the time the Company began to incorporate potential GHG regulation into its resource planning process in 2006, Duke has assumed a cap-and-trade program would be enacted. Even now, with the change in leadership in Congress, many believe that GHG constraints in the form of regulation from the EPA are likely to be implemented. Under this assumption, the Company has sought to develop a cost-effective portfolio of resources that meets customer energy needs while complying with the assumed GHG regulation. Duke stated that its results consistently demonstrate that this is best achieved through a balanced portfolio that includes nuclear, coal, gas, hydro and renewable energy generation, end-use EE, and the purchase of GHG emission allowances. As the proposed emissions cap declines over time, the price of GHG allowances will likely increase. As the prices of GHG allowances increase, additional end-use EE, nuclear, natural gas, and renewable generation will likely be more cost-effective and, over time, will lead the Company to replace coal-fired generation resources as those resources near or reach the end of their economic lives.

Duke explained that coal-fired generation resources, particularly those with environmental controls, will continue to be an important part of the portfolio through at least 2030 over a range of potential GHG allowance prices. To the extent such resources become less economic to operate as part of the Company's portfolio in the future, Duke will make all necessary adjustments to ensure that its generation system is being planned, constructed, and operated at the least reasonable cost to its customers. The Company's current coal fleet includes some of the most economic units on the system, as evidenced by the high capacity factor projections in the 2010 IRP. As Cliffside Unit 6 comes online, the efficiency of Duke's coal fleet will improve even more as the older, less efficient units move even further up the dispatch stack and will ultimately be retired by 2015. Duke will continue to evaluate new GHG regulations as they develop and analyze their ultimate impact on its current generating system. At the present time, the Company believes the selected portfolio within the 2010 IRP, which includes a combination of new nuclear, natural gas, and renewable resources, as well as additional EE and the retirement of all coal generating units without environmental controls, represents the best plan to meet its customers energy needs in the most clean, affordable and reliable way possible over the planning horizon.

Existing Scrubbed Coal Units

According to SACE, neither Duke nor PEC presented in its 2010 IRP any specific analysis of the risks faced by its existing scrubbed coal plants, any assessment of what controls will be needed to be added at each of these units, or whether it will be more economic to add such needed controls than to retire the unit(s). SACE asserted in its comments that this is a serious flaw. Duke's responses to a SACE data request reveal that the Company has prepared some analyses of the costs of adding controls to some of its coal units with SO_2 scrubbers that it does not currently plan to retire. PEC also provided in response to a data request several studies of the cost and economics of retiring some of its older coal units. In addition to showing that retirement of the units at Cape Fear and Weatherspoon is the more economic option, these studies also showed that retirement of the Robinson coal plant by 2014 is the more economic option in almost all of the scenarios studied. SACE argued that the analyses prepared by Duke and PEC should be presented to the Commission in the companies' IRPs to allow the Commission and other parties a full opportunity to review and critique them. In addition, PEC should analyze the economics of the retirement versus continued operation of each of the existing coal units that the Company is not currently planning to retire in the near future.

In its reply comments, Duke explained that coal-fired generation resources, particularly those with environmental controls, will continue to be an important part of its portfolio through at least 2030, over a range of potential GHG allowance prices. To the extent such resources become less economic to operate as part of the Company's portfolio in the future, Duke stated that it would make all necessary adjustments to ensure that its generation system is being planned, constructed and operated at the least reasonable cost to its customers. According to Duke, the Company's current coal fleet includes some of the most economic units on the system as evidenced by the high capacity factor projections in the 2010 IRP.

In its reply comments, PEC stated that its analysis of retiring unscrubbed coal units in its Lee/Wayne and Sutton filings Docket No. E-2, Subs 960 and 968, demonstrated that a significant part of the cost of continued operation was the addition of scrubbers and Selective Catalytic Reduction (SCR) to those units. Scrubbed units would not face these costs, and the existing scrubbers do address, in part, future environmental requirements, including mercury.

Overly Optimistic Growth Projections

According to NC WARN, a review of past IRPs shows that both PEC and Duke have consistently lowered most of their successive projections of increased electricity demand. In comparing its 2005 and 2010 IRPs, Duke's forecasts for peak demand in 2015 decreased by 20.4%. During the same time, the projections for 2025 decreased by 2.0%. In comparing PEC's 2005 and 2010 IRPs, the utility showed no change in peak demand forecast for 2015, but it showed a 9.3% decrease in total sales in 2015. As the IRPs show, both Duke and PEC have experienced nearly flat growth in electricity demand for several years. PEC's actual retail sales grew only 0.3% annually from 2000-2009, and Duke's grew only 0.7% annually from 1994-2009. PEC expects its retail sales of electricity to increase by 1.4% annually through its 15-year planning period. Duke is optimistically projecting 1.5% through its 20-year planning horizon.

According to NC WARN, in its 2009 rate case, Docket E-7, Sub 909, Duke adjusted earlier projections to reflect the impact its rate hike would have on customer usage. The revised estimates projected a slightly negative trend in retail sales over the next five years. Notably, these projections were made in early 2009, before the worst impacts of the current economic recession. It seems likely that because of the current economic situation, consumers will remain cautious and growth in sales will remain flat or decrease, especially as any new purchases of appliances, homes, lighting, HVAC systems and turbines will be considerably more energy efficient than current stock.

According to PEC, NC WARN once again challenged the veracity of PEC's load forecast. In support of its attack, NC WARN asserted that PEC's retail sales only grew 0.3% annually from 2000 to 2009. PEC argued that NC WARN has taken this data out of context to create a very misleading picture of the forecast. PEC's industrial retail sales declined by almost 30% from 2000, (when industrial accounted for about 36% of total retail sales) to 2009. Over the same period, PEC's residential and commercial sales increased by 20%, or about 2.1% per year. In the forward looking years, PEC forecasts a smaller rate of growth in the industrial sector, about 0.8% per year. The growth in PEC's residential and commercial sectors amounts to about a 1.6% growth rate, which is entirely consistent with history. Unless NC WARN wants to present a scenario of continued decline in the industrial sector in NC, and its accompanying loss of jobs and economic health, there is no basis for this assertion.

PEC asserted that, furthermore, in 2008 the Commission conducted a hearing to evaluate the utilities' forecasting process and found it valid. The Public Staff, in its comments in this proceeding, concluded that the assumptions that underlie PEC's peak and energy forecasts are reasonable; that PEC has employed accepted statistical and econometric practices used in forecasting; and that PEC's peak load and energy sales forecasts are reasonable for planning purposes. The Public Staff's conclusions are consistent with the Commission's findings in the 2009, 2008, 2007 and 2006 IRP proceedings.

In its reply comments, Duke maintained that all customer EE activities are captured in the load forecast since that represents metered consumption and the actions of customers in determining how much energy to consume. All of the activities and customer decisionmaking processes associated with energy consumption highlighted by NC WARN are reflected in the historical data and thus represented in the forecasting models used to prepare the Company's load forecast. Similarly, it is an overstatement that load growth has been flat for the past several years. Recent economic events have primarily impacted the industrial sector. However, industrial load growth increased 7% from 2009 to 2010. In addition, excluding the industrial sector, retail load growth has been 1.5% per year for the period 2004 to 2009. It is incorrect to claim that recent slow growth in total sales should imply that it will continue into the future.

Duke stated that the recent declines relating to kWh sales are clearly related to the housing market bust in 2007-2008 and resulting recessionary impacts on the national and regional economies. It is, however, unreasonable to assume that its service territory will continue to experience such a reduction in growth over the entire planning horizon for this IRP. Duke stated that it believes that its load growth projections incorporated into the 2010 IRP are reasonable for planning purposes and that this view is shared by the Public Staff in its comments.

Convening a Workshop or Workgroup

SACE stated in its comments that, if the Commission elects not to schedule an evidentiary hearing on the utility IRPs, the Commission should consider convening a workshop on a limited set of issues. Such a workshop could provide an opportunity for the electric utilities to present their IRPs, and for intervenors to present their analysis of those IRPs to the Commission, and for the Commission to question the parties' representatives on the issues it identifies, without the need for formal witness testimony. In addition, or in the alternative, the Commission may wish to consider establishing a collaborative workgroup to discuss and report on certain issues related to the IRPs and the resource planning process. SACE suggested that such a workgroup would be more effective if it continued to meet after the conclusion of the present docket, so that the workgroup's suggestions and recommendations could inform the utilities' development of the 2011 annual reports and 2012 biennial reports. To enable the full participation of the Public Staff, the Commission may wish to engage a third-party facilitator if it decides to convene such a workgroup.

Duke asserted that it finds SACE's proposal for a technical workshop unnecessary at this time given the opportunity that the parties have had to review and comment upon the IOUs' IRPs.

PEC did not comment on this issue in its reply comments or proposed order.

Conclusions

The Commission finds that PEC and Duke have adequately addressed the issues related to EE, DSM, and portfolio selections in their reply comments. Likewise, both PEC and Duke have offered responses to the issues regarding baseload requirements, the cost of new nuclear generation, GHG emissions, and existing scrubbed coal units that the Commission finds satisfactory and appropriate.

The issue related to overly optimistic growth projections by both PEC and Duke, raised by NC WARN, was also raised by NC WARN in the 2010 evidentiary hearing on IRPs. The Public Staff has reviewed these current forecasts, as it does in every IRP proceeding, and found them to be reasonable for planning purposes. The Commission finds again, as it did in its Order in Docket No. E-100, Sub 124, issued on August 10, 2011, that the growth projections made by PEC and Duke and the resulting energy and peak load forecasts are reasonable and appropriate.

As to the SACE issue of convening a workshop or workgroup, the Commission agrees with Duke that such a process is unnecessary. The existing IRP process allows ample opportunity for intervenor comment and, in fact, allows an intervenor to file an integrated resource plan or report of its own as to any utility.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 6

In its comments, the Public Staff stated that, in addition to new generation to meet load growth, and facilities previously scheduled for retirement, PEC should have also incorporated retirement of additional coal-fired capacity as required by Commission Order dated January 28, 2010, in Docket No. E-2, Sub 960. The retirement plan submitted by PEC in this docket indicated that all unscrubbed coal generation would be retired by December 31, 2017. Robinson Unit 1 is not scrubbed and is not included in the planned retirements. PEC's filing should have included all required retirements.

In its reply comments, PEC responded that it does not understand this recommendation. PEC indicated in its 2010 IRP that it is still evaluating the best course of action for its Robinson coal plant in South Carolina. In contrast to PEC's Cape Fear, Sutton, Lee and Weatherspoon coal plants, all of which PEC has committed to retire by the end of 2014, PEC's Robinson coal plant does have some environmental controls. Also, the natural gas-fired generation to be constructed at PEC's Sutton and Lee plant sites is only sufficient to replace the coal generation at PEC's Lee, Sutton, Cape Fear and Weatherspoon sites. The retirement of PEC's Robinson coal plant would require the construction of additional natural gas-fired generation.

Conclusion

In the absence of continued opposition by the Public Staff, the Commission is of the opinion that PEC has adequately addressed this issue in its reply comments and, therefore, the Commission concludes that the response provided by PEC is satisfactory.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 7

In its comments, the Public Staff requested that PEC and Duke file with their reply comments the specific explanation required by Rule R8-60(i)(3) for each year in which the revised projected reserve margin exceeds plus or minus 3% of the target.

PEC

In its reply comments, PEC stated that the explanation is straightforward. PEC's reserve margin exceeds 3% in those years immediately following the addition of new generation resources, which is to be expected. Resource additions are inherently "lumpy." They cannot economically be added in the exact amount needed each year to maintain an exact reserve margin. PEC's forecasted reserves exceed 3% of PEC's minimum capacity margin target in 2011 and 2012 as a result of the economic addition of the Richmond CC unit as demonstrated in Docket No. E-2, Sub 916. Reserves exceed 3% of PEC's minimum capacity margin target in 2013 and 2014 as a result of the economic addition of the Wayne County CC unit as demonstrated in Docket No. E-2, Sub 960.

Duke

In its reply comments, Duke acknowledged that its system reserve margin is projected to exceed its target reserve margin of 17% by more than 3% over the course of the planning period in the years 2012, 2013, 2014, 2021, 2023, and 2024. These projected increases in reserve margin are driven by the recessionary impacts to load and timing of additions of necessary system generating capacity. Specifically, the additions of Cliffside Unit 6 (825 MW) and the Buck CC facility (620 MW) contribute to the increased reserve margin in 2012, and the addition of the Dan River CC facility (620 MW) further increases the reserve margin above the 17% target in 2013 and 2014. However, by 2015, due to the assumed retirement of over 1,600 MW of coal fired capacity and 370 MW of CT capacity, the reserve margin moves back to within 3% of the Company's target. In 2021, Lee Nuclear Unit 1 (1,117 MW) increases the reserve margin to over 20%. The second Lee Nuclear unit (1,117 MW) in 2023 also increases the reserve margin over 20% in 2023 and 2024. By 2025, the reserve margin is projected to move back within the target range due to continued load growth.

Conclusion

The Commission finds that PEC and Duke have adequately answered the Public Staff in their reply comments.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 8

In its comments, the Public Staff requested:

a) That Duke identify in its reply comments the period during which the double-counting of avoided capacity cost benefits occurred and provide an explanation of the effect of the issue, on any data filed with the Commission, including whether the error influenced Tables 4.1 and 4.2 of the IRP, and provide calculations or other necessary data supporting its response.

b) That Duke should provide in its reply comments a list of all dockets filed with the Commission since January 1, 2005, that included any information, input data, or output results from the DSMore model affected by the double-counting issue.

c) That within 30 days, Duke should file in the respective dockets of each DSM program and pilot approved by, or pending before the Commission, a calculation showing the difference between the avoided cost capacity and energy benefits as originally filed, and the avoided cost benefits recalculated using the correct calculation methodology.

In its reply comments, Duke explained that the Public Staff, in its review of Duke DSM and EE programs, specifically the cost-effectiveness test results of the Company's Power Share Call Option (Docket No. E-7, Sub 953) generated by the DSMore model, observed a calculation of avoided production (energy) costs which seemed relatively high for a DSM program. The cost-effectiveness of the Power Share Call Option and Duke's other Power Share and Power Manager programs, approved in Docket No. E-7, Sub 831, is largely based on avoided capacity costs, and as such, the elimination of the avoided energy cost benefits from the cost-effectiveness results would not change the overall cost-effectiveness of any of the programs.

Duke explained that through the discovery process in this docket, it explained to the Public Staff that the high level of avoided production cost benefits improperly included an amount of avoided capacity cost benefits which were embedded in the inputs used to calculate the avoided production cost benefits. As the Public Staff described in its comments, this DSMore calculation methodology error resulted in a "double-counting" of the avoided capacity cost benefits in Duke's cost-effectiveness evaluations for its Power Share Call Option DSM program. The Public Staff correctly noted that the Company has since corrected the calculation methodology within DSMore to prevent future model runs from performing this incorrect double-counting calculation. The Public Staff also indicated that, based on further discussions with Integral Analytics, LLC, the developer of the DSMore software, it believes that the double-counting of the avoided capacity cost benefits was limited to the overstatements of dollar savings from avoided production cost benefits in the cost-effectiveness tests and did not affect the assumptions of the kilowatt capacity savings from DSM programs represented in Duke's 2010 IRP. Further, the Public Staff stated that it did not believe that any EE program evaluations were impacted by this error, and that the Company's IRP did not need to be adjusted because of this issue. However, the Public Staff stated that it does believe that any erroneous cost-effectiveness test results filed with the Commission in connection with previous DSM program applications should be corrected and refiled in the appropriate dockets, along with an identification from Duke of the period during which the double-counting occurred and an explanation of the effect of the issue on any data filed with the Commission.

Duke has confirmed that the double-counting of avoided capacity cost benefits for its DSM programs occurred during the period of May 2007 to February 2011. As the Public Staff noted in its comments, only DSM programs were impacted, so any values related to EE programs were not impacted. Also, specifically relating to Tables 4.1 and 4.2 of the IRP, which show the respective base case and high case projected load impacts of the Company's EE and DSM portfolio of programs over the planning period, this double-counting did not impact the Company's EE and DSM forecasts as they contain only MW and MWh values. Only dollar amounts related to cost-based avoided production included in certain benefit/cost analyses for DSM programs were impacted. The resulting impact of the double-counting was that the subject DSM programs were shown to be more cost-effective than they otherwise should have been. In any future filings, Duke will remove any double-counting of benefits from all calculations of benefit/cost ratios for DSM programs.

In its reply comments, Duke stated that it will compile a listing of all dockets filed with the Commission since January 1, 2007, that included any information, input data, or output results from the DSMore model and will correct (1) any documents that contained incorrect avoided capacity cost benefits and (2) any documents that contained incorrect cost-effectiveness test evaluations resulting from the DSMore double-counting issue. However, due to the significant number of documents that must be reviewed to determine which may have been impacted, the Company proposed to submit such information within 60 days from the date of this filing. Duke submitted that this additional time was necessary to complete this request in order to properly identify all pertinent documents, correct any necessary miscalculations and supplement the relevant filings as necessary. Duke then filed this information on May 2, 2011.

Conclusion

Based on Duke's responses in its reply comments and its May 2, 2011 supplemental filing, the Commission concludes that Duke has adequately addressed the Public Staff's requests concerning this issue.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The Public Staff observed that French Broad and Blue Ridge did not file IRPs, although NCEMC did include French Broad's load forecast as an appendix to its IRP. Blue Ridge advised the Commission in a letter of July 6, 2009, that it would no longer file IRPs because it had entered into a full requirements power purchase agreement with Duke, and likewise French Broad purchases all of its power requirements from PEC. Prior to 2007, Commission Rule R8-60(b) provided that the requirement to file IRPs applied only to PEC, Duke, DNCP and NCEMC. In that year the Commission amended subsection (b), in Docket No. E-100, Sub 111, to state that the requirement also applied to "any individual electric membership corporation to the extent that it is responsible for procurement of any or all of its individual power supply resources." The Public Staff stated that it believes that French Broad and Blue Ridge, which are responsible for procuring their own power supply resources, are now required by subsection (b) to file IRPs and should begin filing them next year.

In its reply comments, Blue Ridge stated that on September 1, 2006, it entered into a partial requirements power purchase agreement with Duke. Thereafter, on December 17, 2007, Blue Ridge entered into a full requirements power purchase agreement with Duke (the Blue Ridge Agreement). On October 1, 2010, the Blue Ridge Agreement was amended to extend the term until December 31, 2031, and to obligate Duke to provide REPS compliance services for Blue Ridge. Blue Ridge's current and future load requirements are included in Duke's load obligation set forth in Duke's IRP, dated September 1, 2010.

Blue Ridge explained that pursuant to the Blue Ridge Agreement, and as shown in Duke's IRP, Duke's services to Blue Ridge include the delivery of renewable energy resources to Blue Ridge, as well as REPS compliance and reporting services. In accordance with

G.S. 62-133.8(c)(2)(e), Blue Ridge may rely on Duke to provide such services. Accordingly, Duke has aggregated the information required under Commission Rule R8-67 for Blue Ridge into its 2010 REPS compliance plan.

Blue Ridge argued that the filing of an IRP by Blue Ridge, separate and apart from the filing of Duke's IRP, which includes the information for Blue Ridge, would be unnecessarily duplicative. The information required of Blue Ridge by Rule R8-60 and R8-67 is included in the IRP filing of Duke. To require a separate filing by Blue Ridge itself would be an unnecessary expenditure of the time and resources of Blue Ridge in having to prepare such a filing, and of the Public Staff and the Commission in having to review it.

French Broad did not respond to this issue. GreenCo's consolidated REPS compliance plan includes French Broad.

Conclusions

Because both Blue Ridge and French Broad have full requirements contracts with utilities that have an IRP filing obligation, the Commission finds Blue Ridge's argument persuasive. Both Blue Ridge and French Broad are adequately covered through inclusion of their data in existing IRPs and REPS compliance plans.

DISCUSSION AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 10 - 12

In its comments, the Public Staff requested:

a) That all EMCs include a full discussion in future IRPs of their DSM programs and their use of these resources as required by Rule R8-60(i)(6);

b) That Piedmont indicate in its reply comments whether its smart meter program is an EE program, and if so, file for Commission approval of the program pursuant to Rule R8-68; and

c) That EU provide in its reply comments and in future IRPs a more detailed description of the participation and savings related to specific DSM and EE programs, and more particularly any DSM or EE program it proposes to use to meets its REPS obligations.

Conclusions

None of the EMCs addressed these issues in reply comments. In fact, of the EMCs, only Blue Ridge filed any reply comments. The Commission agrees with the Public Staff and, therefore, requires that all EMCs shall include a full discussion in future biennial IRPs of their DSM programs and their use of these resources as required by Rule R8-60(i)(6); that if Piedmont determines that its smart meter program is an EE program, it shall file for Commission approval of the program pursuant to Rule R8-68; and that in future biennial IRPs, EU should provide a more detailed description of the participation and savings related to specific DSM and EE programs, particularly those its proposes to use to meet its REPS obligations.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The Public Staff stated in its comments that, during the 2010 summer, several instances occurred when PEC's reserve margins dropped to low single digit values. These instances coincided with both scheduled and non-scheduled maintenance of generation units, along with abnormally hot weather conditions. No actual emergency situations resulted from these events. The Public Staff argued that this illustrates the importance of the identification of the proper value to use for the reserve margin. At the same time, despite the abnormally hot weather, Duke's reserve margins stayed around 17%.

According to the Public Staff, an inadequate reserve margin results in emergency situations that may lead to expensive emergency purchases or the inability to carry full customer loads in some service areas. On the other hand, a higher than necessary reserve margin results in system costs that are greater than necessary to procure, operate, and maintain excess generation facilities, which results in higher customer rates.

The Public Staff noted that it has been a number of years since either Duke or PEC has conducted a comprehensive study to determine the appropriate reserve and capacity margin values to be used for the planning and operation of their respective systems, and prudent planning requires that such studies be conducted on a periodic basis. Therefore, the Public Staff recommended that the Commission require both Duke and PEC to conduct such studies as soon as practicable and incorporate the results in their IRP process and filings. The studies should determine the optimal level of reserves to provide generation reliability that considers the obligation to serve, the value of electricity, and the effect of outages, while minimizing the cost to ratepayers. It recommended that the studies include, but not be limited to, sensitivity analyses for factors such as the assumed levels of forced outages of generation facilities, assumed level of costs to customers for power outages, assumed values for reliable transmission capacity, and the assumed lead time for adding new generation units. The Public Staff further recommended that the utilities keep the Public Staff updated as they develop the parameters of the studies.

According to PEC, its 2003 reliability analysis formed the basis for its target capacity margin and the 2007 reliability analysis reaffirmed those findings. PEC argued that future updates should be driven by significant changes in input assumptions such as resource mix, outage rates, and load uncertainty. Given that there has not been a significant change in these assumptions, an updated study would produce results similar to the 2003 and 2007 analyses and, thus, an updated study is not warranted at this time.

With regards to PEC's reserve margin adequacy, the Public Staff commented: "Responses to the questions from the Public Staff indicated that the results of the analysis were not available for review and that the analysis had not been performed in a number of years." PEC stated that this comment was the result of a misunderstanding and that PEC did provide the requested data. Given the large amount of data the Public Staff had to review, PEC determined that the Public Staff just overlooked it. PEC provided the Public Staff its 2003 and

2007 Reliability Criteria Studies and the Excel files with supporting data used in developing the study reports.

PEC indicated that it conducts its reliability assessments based on maintaining a LOLE of less than one day in ten years. The one day in ten years LOLE criterion is widely accepted within the industry for establishing generation reliability. This type of analysis does not rely on the costs to customers for power outages. To PEC's knowledge, no utility attempts to capture and incorporate consideration of this variable in its reserve margin analyses. This is primarily due to the fact that any attempt to quantify such a variable would be very subjective. Customer outage costs would be extremely difficult to calculate and would require numerous detailed assumptions regarding individual customers' energy use, the value derived by the customer from that energy use, and the economic consequences of interruptions for individual customers. Such a complex and time-consuming hypothetical exercise would be of no value in determining an appropriate reserve margin.

In its reply comments, Duke stated that it does not dispute that it has not recently conducted a formal comprehensive reserve margin study as it has relied primarily upon historical experience to establish its target reserve margin for planning purposes. A 17% target planning reserve margin level has resulted in adequate reserve amounts in the past and has been deemed reasonable by the Commission in the context of prior IRPs filed by the Company. The Company currently deems such level of reserves to be sufficient to cover the foreseeable risk increases resulting from an aging generation system and resource mix with greater amounts of EE, conservation, DSM, and renewable resources. Duke maintained that, with historical reserves dropping to less than 2% of the peak load within the last five years, a 17% target reserve margin is appropriate. As such, Duke stated that it does not believe that a comprehensive study is required at this time. However, if the Commission believes a comprehensive reserve margin study is necessary, Duke would respectfully request that the Commission order the study be conducted for purposes of the Company's next biennial IRP filing in 2012 due to the fact that the 2011 IRP work will likely be substantially complete prior to an order on the 2010 IRP. In addition, given the proposed merger between the holding companies of Duke and PEC, it makes sense to consider the impact of the merger on the individual and joint reserve margin requirements of the two companies. The proposed merger will still be pending approval before various regulatory agencies at the time of the 2011 IRP filing, and the relevant state and federal regulatory approvals of the proposed joint dispatch arrangement between the operating companies will directly impact resource planning for both companies.

Conclusions

In general, the Commission finds the PEC and Duke responses to the Public Staff's request for a comprehensive study to be reasonable and adequate. However, the Commission is of the opinion that it is appropriate for PEC and Duke to perform an updated comprehensive reserve margin study. Therefore, the Commission directs PEC and Duke to prepare a comprehensive reserve margin requirements study and include it as part of its 2012 biennial IRP report. The Commission also directs Duke and PEC to keep the Public Staff updated as they develop the parameters of the studies.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 14

As it did in its testimony in Docket No. E-100, Sub 124, in regard to the IOUs, the Public Staff encouraged the utilization of DSM resources to achieve fuel savings during periods when the price of energy available for spot purchases is high. It is not evident to the Public Staff that in their IRPs the IOUs have fully considered the use of their DSM resources to achieve fuel savings. The Public Staff recommended that the Commission require both the IOUs and EMCs to investigate this use of their DSM resources and include a discussion of the results of their investigations in their next IRPs.

PEC was aware of the Public Staff's position on this issue and has been investigating the use of its DSM programs to reduce its fuel costs.

In its proposed order, Duke noted that the Public Staff is aware that Duke is continuing to investigate the feasibility of using its DSM resources for fuel savings.

Conclusions

The Commission does not see the correlation between fuel savings and the spot market, as such. The Commission does see the value of possibly activating 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 indeed less expensive to activate DSM resources. The Commission expects IOUs and EMCs to use DSM resources, where available, if such resources are less expensive than spot purchases. The Commission directs each IOU and EMC to address this issue, as a specific item, in their 2012 biennial IRP reports.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The Public Staff encourages each IOU and EMC to investigate, develop, and implement all available cost-effective DSM/EE. Changes being proposed to building codes and appliance standards, as well as federal legislation regarding lighting, will substantially impact the ability to implement cost-effective DSM and EE. These changes will have a profound impact on markets for products that consume electricity and may make reliance on older market potential studies unreliable. Therefore, the Public Staff recommended that any IOU or EMC relying on a DSM/EE market potential study older than two years update its study or perform a new study and file it with its next IRP.

PEC agreed that market potential studies should be periodically updated. However, such updates should be prompted by changed circumstances such as changes in building codes and appliance standards rather than simply the passage of time. PEC's Market Potential study, published in March 2009, incorporated projected Energy Independence and Security Act impacts, including new federal lighting standards. PEC stated that it is unclear whether the Public Staff is recommending that IOUs and EMCs should update their market potential studies every two years going forward, or rather, whether the Public Staff is recommending this specific action during this proceeding based on the recent historical developments outlined in their comments.

Duke also agreed with the Public Staff's assessment regarding older market potential studies and believes that an updated or new DSM/EE market potential study is a worthwhile investment of time and money. As Company witness Richard Stevie stated during the evidentiary hearing on the IRPs conducted in Docket No. E-100, Subs 118 and 124, market potential studies should generally be updated every 5 years. Duke stated that it intends to have a new market potential study completed prior to the filing of its IRP in 2012. However, due to the length of time to properly plan, submit for bid, evaluate and complete such a study, it will not be possible for Duke to have its updated market potential study ready for incorporation into its 2011 IRP. Duke stated that it intends to begin the process of designing and requesting bids for this study in early April, 2011. Should the Commission agree with Public Staff's assessment regarding an updated market potential study, the Company respectfully requested that such a study be required for submission with the next biennial IRP, which will be filed on September 1, 2012.

Conclusions

The Commission finds that the responses of PEC and Duke are adequate. PEC's most current study was published in 2009, and PEC appears unsure as to whether the Public Staff is asking for something more. Duke is planning to submit new information with its 2012 biennial IRP report. Since the Public Staff did not comment by way of a proposed order or brief, the Commission finds that no specific action is required at this time. The Commission does, however, direct each IOU and EMC to ensure that the DSM/EE market potential studies on which they rely are updated as necessary to address current legislation and standards.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 16

The Public Staff stated that, while Duke considered scenarios that assumed the impact of enactment of legislation imposing limits on carbon emissions, it did not include a low- or no-carbon scenario in its development of the proposed expansion plans included in its IRP.

The Public Staff further contended that the filings made by NCEMC and the other EMCs did not indicate that their evaluation of resource options considered the effect of potential legislation placing limits on carbon emissions in conjunction with their individual IRPs. The Public Staff recommended that each electric utility be required to include in its 2011 IRP scenarios with no-carbon and low-carbon price impacts, as well as scenarios factoring in the impact of regulation of carbon emissions. These scenarios should also be included in future IRPs submissions until such scenarios are no longer plausible.

Duke explained in its reply comments that responses it gave to Public Staff data requests indicated that an assumption of no- or low-carbon limitations/costs results in the model selecting coal generation facilities. Based on Duke's policy decisions and perception that additional coal generation would be untenable, the Company decided not to include this type of scenario.

PEC responded that, as explained in PEC's 2010 resource plan, its scenario analyses do include a consideration of various carbon emissions reduction requirements.

Conclusions

Only Duke and PEC chose to comment on this issue. The Commission finds the responses of Duke and PEC to be adequate and that no additional specific action by the electric utilities is required at this time. The current scenarios relating to carbon emissions, as provided in the IRPs, are responsive and appropriate for the purposes of this proceeding.

IT IS, THEREFORE, ORDERED as follows:

1. That this Order shall be adopted as a 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 2010 biennial reports filed in this proceeding by the IOUs, NCEMC, Piedmont, Rutherford, EU, and Haywood are hereby approved.

3. That the 2010 REPS compliance plans filed in this proceeding by the IOUs, GreenCo, Halifax, and EU are hereby approved.

4. That future IRP filings by all utilities 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.

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

6. That future IRP filings by all utilities 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.

7. That French Broad and Blue Ridge shall not be required to file individual IRPs.

8. That all EMCs shall include a full discussion in future biennial IRPs of their DSM programs and their use of these resources as required by Rule R8-60(i)(6).

9. That in future biennial IRPs, EU shall provide a more detailed description of the participation and savings related to specific DSM and EE programs, particularly those its proposes to use to meet its REPS obligations.

10. That any EMC which seeks to implement, or is currently implementing, DSM or EE programs under which incentives are offered to customers (except those programs being filed for approval by GreenCo), shall file such programs for Commission approval under

G.S. 62-133.9(c) and Commission Rule R8-68 if they were adopted and implemented after August 20, 2007.

11. That if Piedmont determines that its smart meter program is an EE program, it shall file for Commission approval of the program pursuant to Rule R8-68.

12. That each IOU and EMC shall investigate the value of activating 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. This issue shall be addressed as a specific item in their 2012 biennial IRP reports.

13. That PEC and Duke shall prepare a comprehensive reserve margin requirements study and include it as part of its 2012 biennial IRP report. PEC and Duke shall keep the Public Staff updated as they develop the parameters of the studies.

ISSUED BY ORDER OF THE COMMISSION.
This the 26th day of October, 2011.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

kh102611.01

DOCKET NO. G-100, SUB 89

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Collection of Data From Natural Gas	)	
Operators Requested By the Pipeline And	)	ORDER REQUIRING REPORT
Hazardous Materials Safety Administration	)	
of the United States Department of	)	
Transportation		

BY THE CHAIRMAN: Pursuant to G.S. 62-50 (b), the North Carolina Utilities Commission (the Commission) has entered into an agreement with the United States Department of Transportation (US DOT) for the regulation of safety standards for natural gas pipelines in North Carolina and receives funds from the US DOT for such regulation.

G.S. 62-50(a) states in part

> The Commission may promulgate and adopt safety standards for the operation of natural gas pipeline facilities in North Carolina. These safety standards shall apply to the pipeline facilities of gas utilities and pipeline carriers under franchise from the Utilities Commission and to pipeline facilities of other gas operators, as defined in subsection (g) of this section. The Commission shall require that all gas operators file with the Commission reports of all accidents occurring in connection with the operation of their gas pipeline facilities located in North Carolina. The Commission may require that all gas operators file with the Commission copies of their construction, operation, and maintenance standards and procedures, and any amendments thereto, and such other information as may be necessary to show compliance with the safety standards promulgated by the Commission.

G.S. 62-50(g) states in part

> For the purpose of this section, "gas operators" include gas utilities and gas pipeline carriers operating under a franchise from the Utilities Commission, municipal corporations operating municipally owned gas distribution systems, regional natural gas districts organized and operated pursuant to Article 28 of Chapter 160A of the General Statutes, and public housing authorities and any person operating apartment complexes or mobile home parks that distribute or submeter natural gas to their tenants.

The Pipeline and Hazardous Material Safety Administration (PHMSA) of the US DOT conducts an annual evaluation of North Carolina's pipeline safety program and a review of North Carolina's certification submittal. The Commission received a letter dated November 30, 2010 from Mr. Zach Barrett of PHMSA concerning PHMSA's annual evaluation and review.

In Mr. Barrett's November 30 letter, he states that "PHMSA has requested State pipeline safety programs to develop statistics on the number of pipeline damages for each one thousand locate request tickets."

The Chairman finds good cause to require the submission of data sufficient to develop such statistics as requested by PHMSA. The Commission Staff will contact operators as to the format of the reporting requirements.

IT IS, THEREFORE, ORDERED that gas operators as defined by G.S. 62-50(g) shall collect and report data concerning damage to their underground facilities as directed by the Commission.

ISSUED BY ORDER OF THE COMMISSION.
This the 19th day of January 2011.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

WG011911.01

DOCKET NO. G-100, SUB 90

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Amendments to Commission Rule R6-2(k)(1)	)	ORDER AMENDING RULES
and Rule R6-19.2(e)	)	

BY THE COMMISSION: The Commission Staff has recommended that certain minor and clarifying changes should be made to Commission Rules R6-2(k)(1) and R6-19.2(e). The Commission finds good cause to adopt the rule changes set forth below.

Because Rule R6-31 was repealed by Order entered in Docket No. G-100, Sub 34 on October 5, 1977, the reference to that Rule contained in Rule R6-2(k)(1) should be deleted. Rule R6-2(k)(1), as so amended, will now read as follows:

> (k) "Cubic foot" of gas as used in these rules shall have the following meanings:
>
> (1) Where gas is supplied and metered to customers at the pressure normally used for domestic customers' appliances, a cubic foot of gas shall be that quantity of gas which, at the temperature and pressure existing in the meter, occupies one cubic foot.

Because North Carolina Natural Gas Corporation (NCNG) was merged into Piedmont Natural Gas Company, Inc., Rule R6-19.2(e) should be amended to delete the references to

"NCNG" and by inserting, instead, Piedmont Natural Gas Company, Inc." or "Piedmont" where appropriate. The reference to "four" municipal gas systems should also be deleted so that no specific number of systems is specified in the Rule. Rule R6-19(e), as so amended, will now read as follows:

> (e) For end users on the municipal gas systems served by Piedmont Natural Gas Company, Inc. (Piedmont), curtailment shall be on the basis of the combined margin they pay to the City and Piedmont (i.e., the rate the end user is paying to the City behind Piedmont's system rather than the rate the City is paying to Piedmont governs those customers' curtailment priority).

These amendments to Rules R6-2(k)(1) and R6-19.2(e) shall be effective as of the date of this Order.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 29th day of April, 2011.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Bb042911.02

DOCKET NO. SP-100, SUB 9
DOCKET NO. SP-967, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. SP-100, SUB 9 In the Matter of Request for Supplemental Declaratory Ruling of Wake Gas Producers, LLC, and Raleigh Steam Producers, LLC DOCKET NO. SP-967, SUB 0 In the Matter of Application of Raleigh Steam Producers, LLC, For Registration of a New Renewable Energy Facility	)	ORDER ON REQUEST FOR SUPPLEMENTAL DECLARATORY RULINGS AND REGISTRATION OF NEW RENEWABLE ENERGY FACILITY

BY THE COMMISSION: On January 7, 2011, Raleigh Steam Producers, LLC (RSP), and Wake Gas Producers, LLC (WGP) (collectively, Petitioners), filed a Petition for Supplemental Declaratory Rulings in Docket No. SP-100, Sub 9. Concurrently, in Docket No. SP-967, Sub 0, RSP filed a report of proposed construction pursuant to Commission Rule R8-65 and a registration statement pursuant to Rule R8-66 for a new renewable energy facility to be located in Raleigh in Wake County, North Carolina. RSP stated that the first phase of its 2.8-MW landfill gas-fueled facility is expected to become operational in late 2011. On March 11, 2011, Petitioners filed an amended Petition, report of proposed construction, and registration statement in the respective dockets.

RSP currently operates two boilers providing steam to Covidien-Mallinckrodt (Mallinckrodt) at its industrial plant in northern Wake County. Boiler 5, the larger of the two, is fueled by landfill gas collected by WGP at the North Wake County Landfill (the Landfill) and sold to RSP. The RSP plant produces no electricity at present and, thus, does not earn any renewable energy certificates (RECs) under the North Carolina Renewable Energy and Energy Efficiency Portfolio Standard (REPS).

Because WGP is producing more gas than RSP can currently use to generate process steam for the Mallinckrodt plant, RSP is considering a two-stage expansion of its plant, with the installation of one or more electric generators operating as combined heat and power (CHP) facilities eligible to earn electric and thermal RECs. The first stage of RSP's expansion project will involve extensive modifications to Boiler 5, the installation of a new Boiler 7, and the installation of a 750-kW low pressure dual steam turbine generator. The two boilers will produce steam for the dual turbines driving the generator, allowing process steam at two separate pressures to be produced and delivered to Mallinckrodt for process steam use. These boilers will continue to burn landfill gas as their primary fuel, but both Boilers 5 and 7 will also burn approximately 10% natural gas. In addition, up to 25% of the fuel for Boiler 7 will consist of a waste process tar generated during pharmaceutical manufacturing operations. Computerized metering equipment will track the proportions of each fuel burned, and no RECs will be sought for power attributable to nonrenewable fuels. At this time, RSP is not requesting a determination by the Commission that the waste process tar is a renewable fuel.

If RSP proceeds with the second phase of its expansion plan, Boiler 7 will be modified to produce steam at a higher temperature and pressure, and a new 790-kW turbine generator will be added. The steam produced in Boiler 7 will be routed to this new turbine generator; the steam produced in Boiler 5 will continue to go to the turbine generator installed in the first phase, which will be operated at a reduced capacity of 410 kW. In addition, as part of the second phase, RSP may install a 1.6-MW landfill gas-fueled CAT 3520 engine/generator set with heat recovery equipment. The waste heat from the engine/generator set will be used to heat feedwater for all of the boilers, including Boilers 5 and 7. RSP stated that, if it actually plans to install electric generating capacity totaling 2 MW or more, it will apply for a certificate of public convenience and necessity pursuant to G.S. 62-110.1. All of the electric power generated on the site will be sold to Progress Energy.

In the Petition, Petitioners request that the Commission hold (1) that RSP's planned expansion would not cause either Petitioner to be a public utility within the meaning of G.S. 62-3(23)(a), to be a utility with the meaning of Commission Rule R6-2(a), or to be "directly or indirectly ... furnishing ... public utility service" within the meaning of G.S. 62-110.1(a), and (2) that the electric and thermal energy produced at RSP's facility will be eligible for RECs under G.S. 62-133.8.

The registration statement included certified attestations that: 1) the facility is or will be in substantial compliance with all federal and state laws, regulations, and rules for the protection of the environment and conservation of natural resources; 2) the facility will be operated as a new renewable energy facility; 3) RSP will not remarket or otherwise resell any RECs sold to an electric power supplier to comply with G.S. 62-133.8; and 4) RSP will consent to the auditing of its books and records by the Public Staff insofar as those records relate to transactions with North Carolina electric power suppliers.

On March 25, 2011, the Public Staff filed a letter recommending that the Commission's acceptance of the registration statement be conditional upon its decision on the declaratory rulings.

The Public Staff presented this matter to the Commission at its regular Staff Conference on June 27, 2011. The Public Staff noted that the Petition presents three primary issues: the public utility status of Petitioners, the CHP status of the proposed generation, and the renewable energy facility status of the new facility.

Public Utility Status

The first issue presented by the Petition is whether the sale of additional steam to Mallinckrodt by RSP, and the construction of the proposed new facilities, will result in either RSP or WGP becoming public utilities. The Commission has already held twice in Docket No. SP-100, Sub 9 that the arrangements WGP and RSP have made with Mallinckrodt do not result in their acquiring public utility status. Order on Request for Amendment to Declaratory Ruling (Nov. 3, 2005); Order on Request for Declaratory Ruling (July 31, 1996). In its 1996 order, the Commission noted that "the use of landfill gas to produce process steam for sale to a single manufacturer under a bargained for transaction did not fall within the definition of a public utility. The Steam Purchase agreement with Mallinckrodt prohibits the resale of steam delivered … and will be for process use only."

The Public Staff stated that, aside from the increased volume of gas being sold to RSP to produce steam for Mallinckrodt's use and the planned construction of new facilities by RSP, there appear to have been no material changes in the contractual relationships among RSP, WGP and Mallinckrodt. The transaction between RSP and Mallinckrodt continues to be a bargained-for sale of steam to a single manufacturer for process use only. With regard to the sale of electricity, RSP stated that the facility will be certified as a qualifying facility pursuant to the federal Public Utility Regulatory Policies Act of 1978 (PURPA), 16 U.S.C. 796, and all of the electricity generated at the facility will be sold to Progress Energy Carolinas, Inc. The Public Staff, therefore, recommended that the Commission grant the requested declaratory ruling that the expansion of RSP's facilities will not cause RSP or WGP to become public utilities.

As noted by the Public Staff, the Commission has considered the arrangements between WGP, RSP and Mallinckrodt on two previous occasions and concluded that neither WGP nor RSP would be considered to be public utilities. The Commission agrees with the Public Staff's analysis that nothing in the proposed expansion would alter that conclusion. The primary change, the addition of electric generating capacity, would not cause RSP to be considered a public utility because all of the electricity generated by RSP will be sold to the local utility. See, Order on Request for Declaratory Ruling, Docket No. SP-100, Sub 0 (Feb. 29, 1984). Therefore, as requested by Petitioners, the Commission concludes that RSP's planned expansion would not cause either WGP or RSP to be a public utility within the meaning of G.S. 62-3(23)(a), to be a utility with the meaning of Commission Rule R6-2(a), or to be "directly or indirectly … furnishing … public utility service" within the meaning of G.S. 62-110.1(a).

CHP Status of the Planned Expansion Project

The Public Staff noted that the second issue presented by the Petition is whether RSP's proposed turbine generators and engine/generator set are sufficiently large to provide the efficiency benefits normally associated with CHP. In other words, are these merely "token" generators, designed to make sure the thermal energy produced by RSP qualifies for RECs under G.S. 62-133.8, but not large enough to provide any practical economic benefit? The Public Staff indicated that it did not believe this to be the case. In its view, the turbine generators are large enough to perform their intended function of regulating the pressure and volume of steam delivered to Mallinckrodt's industrial processes and will result in the generation of a significant amount of electricity. The Public Staff argued that in two recent cases the Commission has found that a proposed facility would generate sufficient electricity to be treated as a legitimate CHP facility, even though electric RECs were expected to constitute only a small portion of the total RECs generated by the facility. W.E. Partners I, LLC, Docket No. SP-729, Sub 1 (July 26, 2010) (in which only 2.5% of the facility's RECs would be associated with electric generation); W.E. Partners II, LLC, Docket No. SP-882, Sub 0 (Jan, 5, 2011) (in which only 2.1% of the facility's RECs would be associated with electric generation). In comparison, the Public Staff stated that it had determined that approximately 2.4% of the RECs produced during the first phase of the expansion at the RSP facility and 4.2% of the RECS produced during the second phase of the expansion will be associated with electric generation.

Whether RSP's proposed electric generating facility is a CHP would be relevant in determining whether it meets the definition of renewable energy facility or new renewable energy facility eligible to earn RECs for some or all of its electric and thermal energy. G.S. 62-133.8(a)(7) defines renewable energy facility, in relevant part, as a facility that "generates useful, measurable combined heat and power derived from a renewable energy resource," including landfill gas. G.S. 62-133.8(a)(1) defines a CHP system as "a system that uses waste heat to produce electricity or useful, measurable thermal or mechanical energy at a retail electric customer's facility."

The Commission concludes that there is no requirement in G.S. 62-133.8 that RECs associated with electricity generation comprise any minimum percentage of the total RECs earned by a CHP facility. The thermal energy for which RECs are sought, however, must be a byproduct of the electric generation that, if not captured and used, would be wasted. A REC is defined, in relevant part, under G.S. 62-133.8(a)(6) as "a tradable instrument that is equal to one megawatt hour of electricity or equivalent energy supplied by a renewable energy facility [or] new renewable energy facility." (Emphasis added.) Thus, a CHP facility may earn RECs for each megawatt-hour of electricity generated from a renewable energy resource as well as each megawatt-hour equivalent of waste heat generated from a renewable energy resource that is captured and used to produce electricity or useful, measurable thermal or mechanical energy at a retail electric customer's facility. Rule R8-67(g)(4) provides that thermal RECs shall be earned based on one REC for every 3,412,000 British thermal units (Btu) of useful thermal energy produced. The prior decisions cited by the Public Staff contain no language to support its contention that there is or should be a minimum amount of RECs associated with electric generation. The Commission, therefore, concludes that a CHP, as provided in G.S. 62-133.8, is simply an electric generating facility that, in addition to generating electricity, also captures and uses heat that would otherwise be wasted in order to produce electricity or useful, measurable thermal or mechanical energy at a retail electric customer's facility.

The statutory requirement that the waste heat be used to produce electricity or useful, measurable thermal or mechanical energy at a retail electric customer's facility prohibits a facility from earning RECs for thermal energy that is reused by the generator itself and is only indirectly used to generate electricity. For example, waste heat captured and used to maintain temperature in an anaerobic digester that is generating the biogas used to generate electricity is not producing useful, measurable thermal or mechanical energy at a retail electric customer's facility. See, Order Accepting Registration of New Renewable Energy Facility, Docket No. SP-578, Sub 0 (Jan. 20, 2010). Rather, it is increasing the efficiency of the generator itself, resulting in more electric generation and associated RECs. Similarly, in this case, waste heat used to pre-heat the feedwater for the boilers that are producing the steam used to generate electricity is not producing useful, measurable thermal or mechanical energy at a retail electric customer's facility, but is increasing the efficiency of the generator itself, and would not be eligible to earn RECs.

"New Renewable Energy Facility" Status

Lastly, the Public Staff noted that the Commission must determine whether the RSP plant, after completion of the planned expansion, will be considered a "new renewable energy facility" under G.S. 62-133.8(a)(5) eligible to earn RECs that can be used for REPS compliance by electric public utilities, an "old" renewable energy facility whose RECs can be used only by electric membership corporations and municipalities, or a combination of old and new facilities. While asserting that the Commission had addressed this issue in several previous decisions, the Public Staff stated that it could discern no clear rule for deciding the issue aside from the statutory requirement that a new renewable energy facility must be "placed into service on or after January 1, 2007." In support of its position, the Public Staff cited four prior Commission decisions, two involving facilities owned by Duke Energy Carolinas, LLC (Duke), and two nonutility-owned facilities.

The Public Staff first noted that, in its June 17, 2009 Order on Public Staff's Motion for Clarification in Docket No. E-100, Sub 113, the Commission considered the question of whether RECs could be earned by a hydroelectric plant with a capacity of more than 10 MW, where the plant is composed of multiple generating units of less than 10 MW capacity. In that order, the Commission agreed with the Public Staff that the individual generating units at the plant would not be considered separate facilities, and further concluded that an electric public utility cannot use utility-owned hydroelectric generation that was placed into service prior to January 1, 2007, for REPS compliance, regardless of the size of a unit or the facility of which it is a part, but that it may use power generated from new or incremental utility-owned hydroelectric generating capacity of 10 MW or less that was placed into service on or after January 1, 2007.

The Public Staff further cited the Commission's June 13, 2008 Order in Docket No. SP-161, Sub 1 in which it granted Coastal Carolina Clean Power, LLC (Coastal), a certificate of public convenience and necessity (CPCN) and accepted registration of its 32 MW biomass-fueled generating plant as a new renewable energy facility. Coastal's plant, originally a coal-fired cogeneration facility, had gone through a series of changes in ownership, had shut down in April 2007, and had been sold at foreclosure. In its application, Coastal indicated that it intended to spend more than $11 million on repairs and renovations to return the plant to service and to allow the plant to burn wood rather than coal.

The Public Staff also cited the Commission's December 17, 2009 Order in Docket No. SP-165, Sub 3 in which EPCOR USA North Carolina, LLC (EPCOR), sought registration as new renewable energy facilities for two coal-fired cogeneration plants it had acquired and modified to burn a mixture of wood waste, tire-derived fuel, and coal. In its order, the Commission held that the modifications were sufficient to allow the plants to be registered as new renewable energy facilities. The Public Staff asserted that the Commission did not elaborate on the basis for this determination, but simply pointed out that the Public Staff had recommended that the facilities should be considered new renewable energy facilities "by virtue of the fuel mix and the extensive and costly modification and additions that are being undertaken" and that the Commission had issued a similar ruling regarding Coastal.

Lastly, noted the Public Staff, in Docket No. E-7, Subs 939 and 940, Duke sought registration as new renewable energy facilities for its Buck and Lee Steam Stations, of which several units had been modified to co-fire biomass. The Commission accepted the registration of the plants as renewable energy facilities, but not as new renewable energy facilities. In its order, the Commission cited the June 17, 2009 Order in Docket No. E-100, Sub 113 as holding that "individual generating units that are components of a larger hydroelectric generating unit are not individual renewable energy facilities." The Public Staff stated that no party contended that only certain generating units at the Buck and Lee plants should be registered as renewable energy facilities.

The Public Staff stated that these four cases differ substantially in their facts and in the conclusions reached, and they do not establish a bright-line rule for determining when a modified or rebuilt plant constitutes a new renewable energy facility. However, it believed that the treatment of incremental generating capacity in the order regarding Duke's hydroelectric plants could provide useful guidance in reaching an equitable decision in this case. In that case, argued the Public Staff, the Commission held, as a general rule, that a "facility" constitutes an entire generating plant. Applying this general rule to RSP, the Public Staff concluded that the plant would most likely have to be ineligible for classification as a new renewable generating facility because Boiler 5 and several other major components of the plant date back to 1997 or earlier. As a result, RSP would not be able to earn any RECs that can be used by electric public utilities for REPS compliance. The Public Staff further argued, however, that the Commission created an exception in that order to its general rule for post-2007 expansion projects at hydroelectric plants providing that, when new capacity is added after 2007 to an existing hydroelectric plant, the incremental capacity will be treated as a new renewable energy facility for REPS purposes.

The Public Staff recommended that this same approach be applied not only to hydroelectric plants, but also to renewable facilities that are not hydroelectric, such as the RSP plant, which burns landfill gas. The Public Staff, therefore, recommended that, following the expansion of the RSP plant, the plant's incremental capacity, over and above its present capacity, should be treated as a new renewable energy facility, earning RECs usable for compliance by electric public utilities. The Public Staff asserted that the same considerations that support applying this special rule to hydroelectric plant expansions are equally applicable to expansions of non-hydroelectric plants, such as RSP. In addition, the modification or expansion of existing renewable energy facilities may be less expensive than construction of new renewable energy facilities, and should be encouraged by the Commission where it would provide a more cost-effective means of compliance with the requirements of G.S. 62-133.8(b) and (c). The Public Staff indicated that it had been provided confidential information regarding the present production of the RSP plant in equivalent megawatt-hours of thermal energy per day. Following the plant expansion, the RSP plant should be treated as an "old" renewable energy facility up to this capacity level; and the incremental capacity above this level should be treated as a new renewable energy facility.

While the Commission's prior decisions in this area might not provide as bright of a line as that sought by the Public Staff, the Commission does not agree that the determination of whether a facility is a renewable energy facility or a new renewable energy facility is as difficult as the Public Staff suggests. With the exception of solar thermal facilities and certain hydroelectric power facilities,[1] a renewable energy facility is a facility that generates electricity by the use of a

[1] The decision in the Commission's June 17, 2009 Order in Docket No. E-100, Sub 113 that Duke's existing hydroelectric facilities less than 10 MW are renewable energy facilities, not new renewable energy facilities, is based on an interpretation of language in G.S. 62-133.8 that is not at issue in this case. In that order, the Commission discussed at length the status of hydroelectric power facilities as renewable energy facilities or new renewable energy facilities, and will not repeat that discussion here. To the extent that the Public Staff is relying on that order to conclude that the three electric generators proposed by RSP at its Mallinckrodt location should be considered to be one "facility," the Commission agrees.

renewable energy resource. In the case of Coastal, EPCOR, and Duke's Buck and Lee plants, each sought registration of a facility that generated some or all of its electricity by the use of renewable energy resources. Thus, each met the definition of renewable energy facility in G.S. 62-133.8(a)(7).

With the exception, again, of certain hydroelectric power facilities and other grandfathered facilities, a new renewable energy facility is defined in G.S. 62-133.8(a)(5) as a renewable energy facility that was placed into service on or after January 1, 2007. The relevant questions, then, to be asked in these and similar cases to determine whether a renewable energy facility is also a new renewable energy facility are, first, whether electric generating equipment had previously been installed and operated at the site, and, if so, whether a substantial investment or improvement was necessary to begin generating some or all of the electricity from renewable energy resources. The facility is a new renewable energy facility if there was no existing capacity to generate electricity at this site or, if there was, a substantial investment or improvement was necessary to begin generating some or all of the electricity from renewable energy resources and the facility was placed into service on or after January 1, 2007.

In each of the cases involving Coastal, EPCOR, and Duke's Buck and Lee plants, electric generating equipment had previously been installed and operated at the site. In the Coastal case, as the Public Staff noted, the owner of the facility invested a substantial amount of money to convert the existing plant from coal to biomass, a renewable energy resource, and to return the plant to service. Thus, an existing facility was substantially rebuilt on or after January 1, 2007, to generate electricity by the use of renewable energy resources. Similarly, in the EPCOR case, existing facilities that had been designed and operated to burn coal exclusively to generate electricity were substantially rebuilt on or after January 1, 2007, to burn a mixture of coal and biomass. Although the Commission noted its similar ruling in the Coastal case, implicitly adopting the reasoning in that case on this issue, it did not specifically state in the EPCOR order that EPCOR had indicated in its application that it intended to spend approximately $80 million to rework, renovate, and repower the facilities. In contrast, in its order in Docket No. E-7, Subs 939 and 940, regarding Duke's Buck and Lee plants, the Commission specifically distinguished the Coastal case in concluding that Duke's existing facilities did not meet the definition of new renewable energy facilities, noting that neither facility required extensive modifications to allow it to burn biomass. The Commission accepted registration of the facilities as renewable energy facilities, but not as new renewable energy facilities, stating,

> Neither facility ... was placed into service after January 1, 2007; rather, Duke witness Beer testified that Buck and Lee were placed into service in the 1950s. Moreover, neither facility required extensive modifications to allow it to burn biomass, as was the case with Coastal Carolina Clean Power in Docket No. SP-161, Sub 1. In fact, in her direct testimony, Duke witness Beer stated that the air permit for Lee already allows Duke to burn certain wood products as an alternative fuel. She further testified on cross-examination that co-firing tests had been undertaken at Lee much earlier than 2007, stating:
>
> > That project [Lee] utilized existing infrastructure from the mid 1990s when the Company [Duke] initially co-fired biomass. And we resurrected it, added a little more money to it, and have been

> burning biomass ever since. The reason that we went there first was because we had that existing infrastructure and were able to test this material in a very low capital way.

Therefore, applying this analysis to the facts in this case, the Commission concludes that RSP's expanded plant, which will generate some or all of its electricity by the use of renewable energy resources, is a renewable energy facility pursuant to G.S. 62-133.8(a)(7). Because there was no existing capacity to generate electricity at this site and the facility is to be placed into service on or after January 1, 2007, RSP's proposed CHP facility further meets the definition of a new renewable energy facility.

Based upon the foregoing and the entire record in this proceeding, including the source of fuel stated in the registration statement, the Commission finds good cause to accept registration of RSP's landfill gas-fueled CHP facility as a new renewable energy facility. Pursuant to Commission Rule R8-67(d)(2), because RSP is using multiple fuels to generate electricity and steam, the facility shall earn RECs based only upon the energy derived from the renewable energy resources in proportion to the relative energy content of the fuels used. As discussed above, only that waste heat generated from a renewable energy resource that is captured and used to produce electricity or useful, measurable thermal or mechanical energy at a retail electric customer's facility is eligible to earn RECs. Thus, RSP shall not earn RECs for steam that bypasses the turbine generators or for waste heat that is used to pre-heat the feedwater for the boilers that are producing steam to be used to generate additional electricity. RSP shall annually file the information required by Commission Rule R8-66 on or before April 1 of each year. RSP will be required to participate in the NC-RETS REC tracking system (www.ncrets.org) in order to facilitate the issuance of RECs.

IT IS, THEREFORE, ORDERED as follows:

1. That the planned expansion of RSP's steam production plant, adjacent to the Mallinckrodt industrial plant in northern Wake County and the Landfill, will not result in RSP or WGP becoming public utilities within the meaning of G.S. 62-3(23)(a), will not cause either of them to be a utility within the meaning of Commission Rule R6-2(a), and will not cause either of them to be "directly or indirectly ... furnishing ... public utility service", within the meaning of G.S. 62-110.1(a).

2. That the registration by RSP for its 2.8-MW landfill gas-fueled CHP facility located in Raleigh in Wake County, North Carolina as a new renewable energy facility shall be, and is hereby, accepted.

3. That RSP shall annually file the information required by Commission Rule R8-66 on or before April 1 of each year.

ISSUED BY ORDER OF THE COMMISSION.
This the 5th day of July, 2011.

NORTH CAROLINA UTILITIES COMMISSION
Patricia Swenson, Deputy Clerk

Commissioners Lorinzo L. Joyner and Susan W. Rabon did not participate.
Bh070511.01

DOCKET NO. SP-100, SUB 27

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Request for a Declaratory Ruling by Green Rite Wilson, Inc.	) ORDER ON REQUEST FOR) DECLARATORY RULING

BY THE COMMISSION: On March 9, 2011, Green Rite Wilson, Inc. (Green Rite), filed a request for the Commission to issue the following declaratory rulings: (a) that the proposed fuel feedstocks to be processed at Green Rite's bio-dryer facilities are "biomass resources" within the definition of "renewable energy resource," G.S. 62-133.8(a)(8); and (b) that the biomass fuel to be produced by Green Rite utilizing these biomass resources is a "renewable energy resource". Green Rite proposes to construct bio-dryer facilities in Wilson and Maxton, North Carolina, to process these biomass resources so that they may be used to produce renewable energy.

In its filing, Green Rite proposed to use the following fuel feedstocks in the production of its biomass fuel: (i) wastewater and water treatment plant biosolids – the solid or semi-solid organic material that is the residual by-product of wastewater and water treatment processes; (ii) wood waste, consisting of pallets, land clearing organic debris, and tree harvesting residues; (iii) organic food waste; and (iv) organic yard waste.

In response to data requests from the Public Staff, Green Rite clarified its request to indicate that it is not seeking to utilize water treatment residuals as a fuel feedstock. Green Rite did indicate, however, that at least one of its potential suppliers of biosolids for Green Rite's Wilson facility commingles water treatment residuals with wastewater treatment biosolids. Green Rite proposes that, if any of its fuel is produced from feedstocks that do not consist exclusively of material that qualifies as biomass resources, it will determine the percentage by weight of the feedstocks comprised of qualifying biomass resources and will designate and market such fuel as having "renewable energy resource" value that is no higher than the percentage by weight of the feedstocks comprised of biomass resources.

Green Rite plans to transport its biomass fuel to an electric generating facility, cement kiln, or other facility where it will either be used as the primary fuel or will be co-fired with coal, other fossil fuels, and/or other renewable energy resources. Assuming the facility meets the definitions of a renewable energy facility or new renewable energy facility in G.S. 62-133.8(a), the electric power or equivalent energy generated from the combustion of Green Rite's fuel will be eligible for compliance with the requirements of G.S. 62-133.8(b) and (c).

Green Rite requests that the Commission issue the following declaratory rulings:

1. Wastewater treatment plant biosolids, wood waste, yard waste, and food waste, when utilized as fuel feedstock at Green Rite's bio-dryer facilities, are biomass resources as that term is defined in G.S. 62-133.8(a)(8).

2. The percentage of Green Rite's resulting biomass fuel that is determined by testing to be biomass, as specifically described in the petition and subject to verification of the

testing procedure and results, is a "renewable energy resource" as defined by G.S. 62-133.8(a)(8).

3. Based on the facts and representations made in the petition, if any of the biomass fuel is produced from feedstocks that do not consist exclusively of materials that qualify as biomass resources, it may be designated and marketed as having "renewable energy resource" value that is no higher than the percentage by weight of the feedstocks comprised of biomass resources.

In support of its request, Green Rite states that granting its requested relief will further the policy goals of G.S. 62-2(a)(10) by helping to: (i) diversify the resources used to reliably meet the energy needs of consumers in the State; (ii) provide greater energy security through the use of indigenous energy resources available within the State; (iii) encourage private investment in renewable energy and energy efficiency; (iv) provide improved air quality and other benefits to energy consumers and citizens of the State; and (v) provide a beneficial use for resources that might otherwise be disposed of in landfills.

Interpretation of "Renewable Energy Resource"

The requested declaratory ruling requires a decision by the Commission as to whether the combination of fuel feedstocks described in the petition are "biomass resources" within the definition of a "renewable energy resource" pursuant to G.S. 62-133.8(a)(8). "Renewable energy resource" is defined as follows:

> [A] solar electric, solar thermal, wind, hydropower, geothermal, or ocean current or wave energy resource; a biomass resource, including agricultural waste, animal waste, wood waste, spent pulping liquors, combustible residues, combustible liquids, combustible gases, energy crops, or landfill methane; waste heat derived from a renewable energy resource and used to produce electricity or useful, measurable thermal energy at a retail electric customer's facility; or hydrogen derived from a renewable energy resource. (Emphasis added.)

In its February 29, 2008 Order Adopting Final Rules in Docket No. E-100, Sub 113, the Commission adopted Rules R8-66 and R8-67 to implement the Renewable Energy and Energy Efficiency Portfolio Standard (REPS) established by the General Assembly in Session Law 2007-397 (Senate Bill 3). In that Order, the Commission concluded that the determination of whether a resource is a "biomass resource" or a "renewable energy resource" should be made on a case-by-case basis. In Docket No. SP-165, Sub 3, by Order dated December 17, 2009, the Commission concluded that, although Senate Bill 3 did not include the term "organic" in its definition of renewable energy resource, this term is inherent in the use of the word "biomass," noting that the North Carolina Biomass Council, in its 2007 Biomass Roadmap, defined "biomass" as "any organic matter that is available on a renewable or recurring basis."

The Commission has previously ruled in separate proceedings that fuel feedstocks similar to those that Green Rite plans to process to generate biomass fuel are biomass resources or renewable energy resources. In Docket No. SP-100, Sub 25, by Order dated February 24, 2010, the Commission found that "biosolids, the organic material remaining after treatment of domestic sewage ... are a 'renewable energy resource' as defined by G.S. 62-133.8(a)(8)." In Docket No. SP-161, Sub 1, by Order dated June 13, 2008, the Commission approved the registration of a new renewable energy facility, in part, based on its source of fuel, which consisted of various wood waste products, including railroad ties, engineered wood products, and other wood waste. In addition, in Docket No. E-7, Subs 939 and 940, by Order dated October 11, 2010, the Commission (Commissioner Culpepper, dissenting) interpreted the term "biomass resource" to include not only wood waste, but also "primary harvest wood products, including wood chips from whole trees." In Docket No. SP-100, Sub 28, by Order dated April 18, 2011, the Commission issued a declaratory ruling that yard waste (the leaves, brush, grass clippings, and tree limbs generated in the region), when utilized as fuel at a proposed biomass-to-energy facility, is a renewable energy resource within the definition of G.S. 62-133.8(a)(8). In Docket No. SP-297, Sub 1, by Order dated March 12, 2010, the Commission accepted registration of a new renewable energy facility that will use organic wastes that include "food waste, vegetative waste from landscaping operations, paper and cardboard, agricultural and animal waste, and food processing waste" as fuel.

With regard to the consideration of renewable energy resources that are commingled with non-qualifying materials, the Commission has considered this issue in several proceedings. In Docket No. SP-165, Sub 3, by Order dated December 17, 2009, the Commission concluded that a facility "should be allowed to earn RECs for that percentage of [tire-derived fuel] that can be demonstrated, through the submission of appropriate additional primary reference materials in this docket, to be derived from natural rubber." In Docket No. SP-100, Sub 23, by Order dated March 25, 2009, the Commission held that "the percentage of [Solid Recovered Fuel's] refuse-derived fuel (RDF) that is determined by testing to be biomass ... is a 'renewable energy resource' as defined in G.S. § 62-133.8(a)(8)," and that "the same percentage of the Syngas produced from that RDF, subject to the same conditions, also is a 'renewable energy resource.'" Green Rite similarly proposes to monitor the source, nature, and quantities of all feedstocks received and processed by its facilities and maintain such records for a period of at least three years.

Public Staff Recommendation

The Public Staff presented this matter to the Commission at its Regular Staff Conference on May 9, 2011. With respect to the definition of "renewable energy resource," the Public Staff stated that, based upon the facts and representations made in the request, it recommends that the Commission declare that the proposed fuel feedstocks to be processed at Green Rite's bio-dryer facilities are biomass resources, and that the resulting biomass fuel is a "renewable energy resource" as that term is defined by G.S. 62-133.8(a)(8).

On May 18, 2011, the Public Staff filed a letter modifying its recommendation and proposed order to provide that the determination of what portion of Green Rite's biomass fuel qualifies as a "renewable energy resource" pursuant to G.S. 62-133.8(a)(8) should be based on the relative energy content of the feedstock, rather than weight. In particular, the Public Staff recommends that, in the event some portion of Green Rite's biomass fuel is produced from feedstocks that do not consist exclusively of materials that qualify as biomass resources, the renewable energy resource content of the resulting fuel should be determined based on the portion of the total energy content of the fuel that was derived from feedstocks that qualify as renewable energy resources. Further, if Green Rite determines that the renewable energy resource content of any of its biomass fuel is less than 100%, it should provide such information to the buyer of such biomass fuel and, upon request, to the Commission and Public Staff.

Commission Conclusion

Based upon a careful consideration of the facts and representations in Green Rite's request and the Public Staff's recommendation, the Commission concludes that Green Rite's request for declaratory rulings should be granted subject to the conditions recommended by the Public Staff regarding biomass fuel that is produced from feedstocks that do not consist exclusively of materials that qualify as biomass resources.

The Commission notes that the present decision is limited to the facts set forth in this Order and Green Rite's request and should not be regarded as a precedent for any other person engaging in activities other than those found in this case.

IT IS, THEREFORE, ORDERED as follows:

1. That wastewater treatment plant biosolids, wood waste, yard waste, and food waste, when utilized as fuel feedstock at Green Rite's bio-dryer facilities, are biomass resources as that term is defined in G.S. 62-133.8(a)(8);

2. That the percentage of Green Rite's biomass fuel that is determined by testing to be biomass, as specifically described in the petition and subject to verification of the testing procedure and results, as appropriate, is a "renewable energy resource" as defined by G.S. 62-133.8(a)(8);

3. That, if any of Green Rite's biomass fuel is produced from feedstocks that do not consist exclusively of materials that qualify as biomass resources, Green Rite shall determine the renewable energy resource content of its biomass fuel based on the portion of the total energy content of the fuel that was derived from feedstocks that qualify as renewable energy resources; and

4. That, if Green Rite determines the renewable energy resource content of any of its biomass fuel to be less than 100%, it shall provide such information to the buyer of such biomass fuel and, upon request, to the Commission and the Public Staff.

ISSUED BY ORDER OF THE COMMISSION.
This the 24th day of May, 2011.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Sw052411.02

DOCKET NO. SP-100, SUB 28

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Request for a Declaratory Ruling by	)	ORDER ON REQUEST FOR
ReVenture Park Investments I, LLC	)	DECLARATORY RULING

BY THE COMMISSION: On March 15, 2011, ReVenture Park Investments I, LLC (ReVenture), filed a request for a declaratory ruling in the above-captioned docket regarding an electric generating facility that it plans to develop in Charlotte, North Carolina. ReVenture states that it is transforming a 667-acre dormant industrial site along the Catawba River into that region's first Renewable Energy Eco-Industrial Park (the Eco-Park). ReVenture is proposing to construct a 20-megawatt (MW) biomass-to-energy facility (BTE Facility) within the Eco-Park that will burn synthesis gas (Syngas) produced from yard waste and refuse-derived fuel (RDF) to produce steam to generate electricity. ReVenture also states that it has submitted a proposal to an electric power supplier and entered into negotiations for a power purchase agreement for the electric power and renewable energy certificates (RECs) generated from the proposed BTE Facility.

ReVenture requests that the Commission rule as follows:

a) That yard waste (the leaves, brush, grass clippings and tree limbs) used as fuel at ReVenture's BTE Facility is a "renewable energy resource" as defined by G.S. 62-133.8(a)(8).

b) That the percentage of RDF that is determined by testing to be biomass and that is used for fuel at the BTE Facility is a "renewable energy resource" as defined by G.S. 62-133.8(a)(8).

c) That the percentage of Syngas produced by the BTE Facility from yard waste and the portion of RDF determined by testing to be biomass is a renewable energy resource as defined by G.S. 62-133.8(a)(8), where the percentage of Syngas is weighted to reflect the energy derived from renewable energy resources used in its production in proportion to the relative energy content of the fuels used (the Renewable Energy Percentage).

d) That, under Section 4 of Session Law 2010-195 (Senate Bill 886), the total RECs generated annually from renewable energy resources at all biomass new renewable energy facilities located on tracts of land designated by the North Carolina Secretary of State as cleanfields renewable energy demonstration parks pursuant to Senate Bill 886, to which triple credits may apply, may not exceed the eligible output of the first 20 MW of capacity in all cleanfields renewable energy demonstration parks in the State. Any capacity beyond 20 MW in such demonstration parks would be eligible to earn RECs pursuant to G.S. 62-133.8, but such RECs would not be eligible for triple credit pursuant to Senate Bill 886.

e) That, if the BTE Facility is determined by the Commission to be a biomass new renewable energy facility and is located on a tract of land designated by the North Carolina Secretary of State as a cleanfields renewable energy demonstration park pursuant to Senate Bill 886, the number of RECs earned from the generation of electricity by the BTE Facility will be a function of the capacity factor of the BTE Facility and the Renewable Energy Percentage of the Syngas used.

f) That RECs generated by the BTE Facility will be recorded in its North Carolina Renewable Energy Tracking System (NC-RETS) account as a unique fuel type, e.g., "S886 Biomass," and one megawatt-hour (MWh) so recorded will equal a single REC. The electric power supplier that purchases such a REC for compliance with G.S. 62-133.8 will receive one S886 Biomass REC. When the electric power supplier retires the one S886 Biomass REC, it will receive triple credit, resulting in one general obligation REC and two additional credits. The electric power supplier will use and retire the S886 Biomass REC and the two additional credits described in Section 4 of Senate Bill 886 for compliance purposes in accordance with the NC-RETS Operating Procedures.

g) That the additional credits 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 be utilized to comply with G.S. 62-133.8(b) and (c).

h) That the normal provisions on banking RECs contained in Commission Rule R8-67 apply equally to the RECs described in Section 4 of Senate Bill 886, and nothing in Rule R8-67 or in Senate Bill 886 limits the order in which an electric power supplier may retire banked RECs.

In support of its request, ReVenture argued that granting its requested relief will further the policy goals of G.S. 62-2(a)(10) by (a) diversifying the resources used to reliably meet the energy needs of consumers in the State; (b) providing greater energy security through the use of indigenous energy resources available within the State; (c) encouraging private investment in renewable energy and energy efficiency; and (d) providing improved air quality and other benefits to energy consumers and citizens of the State.

On April 4, 2011, Blue Ridge Environmental Defense League, Inc. (BREDL), filed a petition to intervene, which was granted by Order issued April 7, 2011. The Public Staff presented this matter to the Commission at its Regular Staff Conference on April 4, 2011.

<u>Definition of "Renewable Energy Resources"</u>

The first three requested declaratory rulings require decisions by the Commission as to whether yard waste, RDF and Syngas, as described in the petition, are "renewable energy resources" as defined by G.S. 62-133.8(a)(8). "Renewable energy resource" is defined as follows:

> a solar electric, solar thermal, wind, hydropower, geothermal, or ocean current or wave energy resource; a biomass resource, including agricultural waste, animal

> waste, wood waste, spent pulping liquors, combustible residues, combustible liquids, combustible gases, energy crops, or landfill methane; waste heat derived from a renewable energy resource and used to produce electricity or useful, measurable thermal energy at a retail electric customer's facility; or hydrogen derived from a renewable energy resource. "Renewable energy resource" does not include peat, a fossil fuel, or nuclear energy resource.

ReVenture argues that yard waste, the percentage of RDF determined by testing to be biomass, and the percentage of Syngas attributable to these renewable energy resources are each a biomass resource, which is included in the definition of renewable energy resource. ReVenture argues that the list of resources following the words "biomass resource, including" in the definition of renewable energy resource is a list of examples, not an exhaustive list. ReVenture cites the definition of biomass, "[a]ny organic matter that is available on a renewable or recurring basis," adopted by the North Carolina Biomass Council in its May 2007 Biomass Roadmap.

First, ReVenture requests that the Commission declare that the yard waste proposed for use in the BTE Facility, which it intends to source from the Mecklenburg County Compost Central Facility, is a renewable energy resource. ReVenture argues that yard waste, which is comprised of leaves, brush, grass clippings, and tree limbs, is all organic plant material. ReVenture argues that these materials are "waste" in the same sense as wood waste, which is included in the statutory definition of biomass. In addition, notes ReVenture, the United States Environmental Protection Agency recognizes yard waste as an organic material.

Second, ReVenture requests that the Commission declare that the percentage of RDF, determined by testing to be biomass, proposed for use in the proposed BTE Facility is a renewable energy resource. ReVenture states that RDF is derived from municipal solid waste (MSW) that is collected at the curb by Mecklenburg County. The MSW is separated into component materials: including metals, glass, large cardboard items, certain plastics, and other materials for recycling; the majority of paper, certain cardboard, paper packaging, and small items of wood for processing into RDF; and residual "unusable waste" for transporting to a landfill. The separated MSW will be processed and shredded into small particle sizes and packed for shipment to ReVenture Park as RDF for use as fuel at the proposed BTE Facility. ReVenture argues that the Commission, in its March 25, 2009 Order in Docket No. SP-100, Sub 23, previously concluded that RDF derived from MSW that is determined by testing to be biomass, subject to verification of the testing procedures and results, is a renewable energy resource, as defined in G.S. 62-133.8(a)(8).

Lastly, ReVenture requests that the Commission declare that the percentage of Syngas, a combustible gas produced from the yard waste and RDF, is a renewable energy resource where the percentage of Syngas is weighted to reflect the energy derived from renewable energy resources used in its production in proportion to the relative energy content of the fuels used. ReVenture notes that Commission Rule R8-67(d)(2) provides that,

> for any facility that uses both renewable energy resources and nonrenewable energy resources to produce energy, the facility shall earn [RECs] based only upon the energy derived from renewable energy resources in proportion to the relative energy content of the fuels used.

ReVenture states that the Syngas used as fuel by the proposed BTE Facility is produced from a combination of renewable energy resources (yard waste and the biomass percentage of the RDF) and nonrenewable energy resources (the non-biomass percentage of the RDF). ReVenture proposes that only the percentage of Syngas attributable to the renewable energy resources be used in calculating RECs earned by the proposed BTE Facility, taking into account the relative Btu value of the yard waste and the percentage of RDF determined by testing to be biomass.

In its comments, BREDL opposes ReVenture's requests that yard waste, RDF and Syngas be declared to be renewable energy resources. It argues that, to be renewable, a source of energy must renew, recharge or regenerate itself. While this would "plainly include wind, solar and hydro energy sources," argues BREDL, RDF and municipal yard waste are not acceptable energy resources. BREDL argues that yard waste should not be considered as a fuel for energy production because, first, it is recyclable as compost and need not be deposited in a landfill. Second, Mecklenburg County operates a municipal yard waste composting facility, and there is no benefit to the public or the environment to divert the yard waste from this facility to the proposed BTE Facility. BREDL further objects to ReVenture's request that RDF be declared to be a renewable energy resource. BREDL argues that RDF, or MSW, is not present in the definition of renewable energy in G.S. 62-133.8(a)(8). BREDL notes that the Commission, in its Order in Docket No. SP-100, Sub 23 regarding RDF, stated that its decision should not be regarded as precedent for any other person engaging in activities other than those found in that case. BREDL argues that the Commission's Order in that case relied solely on the interpretations, descriptions and assertions of industry representatives seeking the declaratory ruling. BREDL challenged the SO_x, NO_x and CO_2 emission reductions claimed in that case, stating that, for many pollutants, biomass units are dirtier than coal-fired power plants: "The use of biomass fuel will not reduce levels of carbon dioxide in the atmosphere; therefore, it cannot be part of the solution to global warming in the 21st Century." In conclusion, BREDL argues:

> ReVenture has failed to meet its burden in its request to have refuse derived fuel and yard waste deemed renewable energy resources. Granting the REQUEST would not reduce the amount of yard waste going to the landfill, it would simply take it from a viable county-wide composting operation. Further, the combustion of refuse derived fuel would have a negative impact on air quality in Charlotte and would not reduce greenhouse gas emissions. ... We respectfully request that the Commission deny the REQUEST.

In presenting this agenda item to the Commission, the Public Staff supports ReVenture's request and recommends, based upon the facts and representations made in the request, that the Commission declare that yard waste and the percentage of RDF determined by testing to be biomass, when utilized as fuel at ReVenture's proposed BTE Facility, are renewable energy resources as that term is defined by G.S. 62-133.8(a)(8). In addition, the Public Staff recommends that the Commission declare that the percentage of Syngas produced from these fuels is a renewable energy resource as defined by G.S. 62-133.8(a)(8), when calculated as proposed by ReVenture.

After careful consideration of the entire record in this docket, including the Public Staff's recommendations, the Commission concludes, as requested by ReVenture, that yard waste, the percentage of RDF determined by testing to be biomass, and the percentage of Syngas attributable to these renewable energy resources are each a biomass resource and a renewable energy resource. In its February 29, 2008 Order Adopting Final Rules in Docket No. E-100, Sub 113, the Commission adopted Rules R8-66 and R8-67 to implement the Renewable Energy and Energy Efficiency Portfolio Standard (REPS) established by the General Assembly in Session Law 2007-397 (Senate Bill 3). In that Order, the Commission concluded that the determination of whether a resource is a "renewable energy resource" or a "biomass resource" should be made on a case-by-case basis.

As ReVenture notes, the Commission, in Docket No. SP-100, Sub 23, has previously considered RDF and Syngas and determined that the percentage of RDF determined by testing to be biomass and the percentage of Syngas derived therefrom are renewable energy resources. The case-by-case determination referenced in the February 29, 2008 Order in Docket No. E-100, Sub 113 was with regard to particular fuels, not facilities. The Commission is not persuaded that there is any reason to reach a different conclusion in this docket regarding RDF and Syngas.

With regard to yard waste, it is undisputed that yard waste is organic plant material and that organic plant material is biomass. The only question, then, is whether yard waste, which is not specifically mentioned in the definition of biomass resource in G.S. 62-133.8(a)(8), is a renewable energy resource. In its October 11, 2010 Order in Docket No. E-7, Subs 939 and 940, the Commission allowed Duke Energy Carolinas, LLC, to earn RECs from the combustion of wood chips derived from whole trees. In that case, the Commission noted that neither the statute nor the Commission's rules implementing Senate Bill 3 defines biomass resource, and concluded that the list of biomass resources identified in the statute was not exhaustive, but merely illustrative. Similarly, in this case, the Commission concludes that yard waste, a biomass resource, meets the definition of renewable energy resource.

BREDL would have the Commission declare that yard waste and RDF derived from MSW are not renewable energy resources. The Commission, however, concludes that the General Assembly has already made the decision that biomass, including yard waste and the percentage of RDF determined to be biomass, are renewable energy resources. In interpreting the statutory definition, the Commission must first look to the language of the statute. A statute that is clear and unambiguous must be construed using its plain meaning. Burgess v. Your House of Raleigh, Inc., 326 N.C. 205, 209, 388 S.E.2d 134, 136 (1990). Notwithstanding BREDL's arguments about the relative emissions from biomass, it is clear from the language of the statute that the General Assembly considered this issue and specifically intended to include biomass resources as renewable energy resources. In addition to the explicit inclusion of biomass resource in the definition of renewable energy resource, G.S. 62-133.8(g) provides that a biomass combustion process at any new renewable energy facility that delivers electric power to an electric power supplier shall meet Best Available Control Technology (BACT) regarding the emission of air pollutants.

The Commission, therefore, concludes that ReVenture's first three requests for declaratory ruling should be granted

Interpretation and Implementation of Senate Bill 886

The remaining five declaratory rulings requested by ReVenture are related to the appropriate interpretation and implementation of Section 4 of Senate Bill 886, which provides as follows:

> Renewable energy generation. – The definitions in G.S. 62-133.8 apply to this act. If the Utilities Commission determines that a biomass renewable energy facility located in the cleanfields renewable energy demonstration park is a new renewable energy facility, the Commission shall assign triple credit to any electric power or renewable energy certificates 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 additional credits shall be eligible for use to meet the requirements of G.S. 62-133.8(f). The additional credits 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 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. [Emphasis added.]

ReVenture states that it will seek certification of the Eco-Park as a cleanfields renewable energy demonstration park from the Secretary of State pursuant to Section 3 of Senate Bill 886, and that it will file such certification with the Commission. If the Eco-Park is designated as a cleanfields renewable energy demonstration park by the Secretary of State and the BTE Facility is determined to be a biomass renewable energy facility and a new renewable energy facility by the Commission, ReVenture proposes that the RECs earned by the BTE Facility be calculated as follows: (1) the total capacity of the BTE Facility (up to a maximum of 20 MW) will be multiplied by the number of hours in a calendar year; (2) the product of Step 1 will be multiplied by the capacity factor of the BTE Facility; and (3) the product of Step 2 will be multiplied by the Renewable Energy Percentage of the Syngas, as defined above. ReVenture requests a declaratory ruling that the total RECs generated annually from renewable energy resources at all biomass new renewable energy facilities located on tracts of land designated by the North Carolina Secretary of State as cleanfields renewable energy demonstration parks pursuant to Senate Bill 886, to which triple credits may apply, may not exceed the eligible output of the first 20 MW of capacity in all cleanfields renewable energy demonstration parks in the State. Any capacity beyond 20 MW in such demonstration parks would be eligible to earn RECs pursuant to G.S. 62-133.8, but such RECs would not be eligible for triple credit pursuant to Senate Bill 886.

ReVenture further requests that the Commission declare that RECs generated by the proposed BTE Facility be recorded in its NC-RETS account as a unique fuel type, e.g., "S886 Biomass," and that one megawatt-hour so recorded will equal a single S886 Biomass REC. The electric power supplier that purchases such a REC from ReVenture for compliance with G.S. 62-133.8 will receive one S886 Biomass REC. When the electric power supplier retires the one S886 Biomass REC, it will receive triple credit, resulting in one general obligation REC and two additional credits. The additional credits are eligible for use to meet the poultry waste resource set-aside 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 be utilized to comply with the general REPS requirements of G.S. 62-133.8(b) and (c). Lastly, ReVenture requests that the Commission declare that the triple credit ceases to apply after its application to the first 20 MW of biomass renewable energy facility generation capacity located in all cleanfields renewable energy demonstration parks in the State.

In its comments, BREDL did not address these issues, stating that they are irrelevant if the fuels are not recognized as renewable energy resources.

In presenting this agenda item to the Commission, the Public Staff supports ReVenture's request and recommends that the Commission issue an order granting the declaratory rulings requested by ReVenture.

After careful consideration of the entire record in this docket, including the Public Staff's recommendations, the Commission concludes that ReVenture's sixth, seventh and eighth requests for declaratory rulings should be granted.

With regard to ReVenture's sixth and seventh requests for declaratory rulings, the Commission agrees that RECs associated with energy produced by the proposed BTE Facility should be recorded in NC-RETS as a unique fuel type and that an electric power supplier that purchases and retires such a REC for compliance with G.S. 62-133.8 will receive one general biomass REC and two additional credits that must first be used to meet the REPS poultry waste set-aside requirement. In order to address concerns of other REC tracking systems across the nation that one REC represents one megawatt-hour of renewable energy generation, NC-RETS will only create the one REC actually associated with the one megawatt-hour of generation by the proposed BTE Facility. The REC and the additional credits will be retired for REPS compliance in accordance with the NC-RETS Operating Procedures.

With regard to ReVenture's eighth request, the Commission agrees that, except for the triple credit, all of the provisions of G.S. 62-133.8 and Rule R8-67 would apply equally to the RECs associated with energy produced by the proposed BTE Facility as to RECs associated with energy produced at any other renewable energy facility.

With regard to ReVenture's fourth and fifth requests for declaratory rulings, however, the Commission is not persuaded that the calculations proposed by ReVenture are necessary. In this case, ReVenture states that the proposed BTE Facility will only be capable of producing up to 20 MW of electricity. Thus, because the triple credit is limited "to the first 20 megawatts of biomass renewable energy facility generation capacity located in all cleanfields renewable energy demonstration parks in the State," all of the RECs earned by ReVenture would be eligible for the triple credit. Accounting for the capacity factor of the generating facility would only appear to be relevant if the capacity of the BTE Facility were proposed to be greater than 20 MW and the output from the facility were required to be allocated between the first 20 MW and the remaining capacity. Such is not proposed in this case regarding ReVenture's BTE Facility.

The Commission additionally declines to grant the fourth declaratory ruling requested by ReVenture because it appears to ignore the possibility that the facility may also earn RECs from the capture and use of waste heat as a combined heat and power facility. In its request, ReVenture does not define what it means by "eligible output." 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 further declines to grant ReVenture's fifth request for declaratory ruling, whereby the number of RECs earned from the generation of electricity by the proposed BTE Facility would be a function of the capacity factor of the BTE Facility and the percentage of Syngas determined to be derived from renewable resources. Commission Rule R8-67(g)(1) states that "the electric power generated by a renewable energy facility shall be measured by an electric meter supplied by and read by an electric power supplier." The NC-RETS Operating Procedures outline procedures for creating RECs from facilities that use multiple fuels, some of which do not qualify for RECs. ReVenture has not provided any explanation as to why these rules and procedures should not apply to the proposed BTE Facility. Therefore, the Commission will decline to grant ReVenture's fifth request for a declaratory ruling.

The Commission notes that the present decision is limited to the facts set forth in this Order and ReVenture's request and should not be regarded as a precedent for any other person engaging in activities other than those found in this case.

IT IS, THEREFORE, ORDERED as follows:

1. That yard waste (the leaves, brush, grass clippings and tree limbs) and the percentage of RDF, determined by testing to be biomass, when utilized as fuel at ReVenture's proposed BTE Facility, are renewable energy resources as that term is defined by G.S. 62-133.8(a)(8).

2. That the percentage of Syngas produced by the proposed BTE Facility from yard waste and the percentage of RDF determined by testing to be biomass is a renewable energy resource as defined by G.S. 62-133.8(a)(8), where the percentage of Syngas is weighted to reflect the energy derived from renewable energy resources used in its production in proportion to the relative energy content of the fuels used.

3. That, under Section 4 of Senate Bill 886, the triple credit shall apply only to the first 20 MW of biomass renewable energy facility generation capacity located in all cleanfields renewable energy demonstration parks in the State, and that, while any capacity beyond 20 MW

in such demonstration parks would be eligible to earn RECs pursuant to G.S. 62-133.8, such RECs are not eligible for the triple credit pursuant to Senate Bill 886.

4. That the number of RECs earned from the generation of electricity by the proposed BTE Facility will be determined based on meter readings by an electric power supplier and the NC-RETS Operating Procedures' provisions regarding calculating RECs from multi-fuel facilities.

5. That RECs eligible for the triple credit pursuant to Section 4 of Senate Bill 886 will be recorded in NC-RETS as a unique fuel type, and that one megawatt-hour so recorded will equal a single REC of that type.

6. That the electric power supplier that purchases a REC eligible for the triple credit pursuant to Section 4 of Senate Bill 886 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.

7. That the electric power supplier will use and retire the REC eligible for the triple credit pursuant to Section 4 of Senate Bill 886 and the two additional credits in accordance with the NC-RETS Operating Procedures.

8. That the additional credits associated with a REC eligible for the triple credit pursuant to Section 4 of Senate Bill 886 are eligible for use to meet the requirements of G.S. 62-133.8(f), and that 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 be utilized to comply with G.S. 62-133.8(b) and (c).

9. That, 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 energy produced by the proposed BTE Facility as to RECs associated with energy produced at any other renewable energy facility.

ISSUED BY ORDER OF THE COMMISSION.
This the 18th day of April, 2011.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Commissioner William T. Culpepper, III, concurs. Chairman Edward S. Finley, Jr. and Commissioner Bryan E. Beatty did not participate.

Sw041811.02

DOCKET NO. SP-100, SUB 28

Commissioner William T. Culpepper, III, concurring:

I write separately to concur in the decision in this Order on Request for Declaratory Ruling. I dissented, in part, in the Commission's October 11, 2010, Order Accepting Registration of Renewable Energy Facilities in Docket No. E-7, Subs 939 and 940 on the issue of whether whole trees harvested for the purpose of electricity generation qualify as a biomass resource and a renewable energy resource under Senate Bill 3. As in that case, I believe that, in enacting Senate Bill 3, the legislature intended that only certain limited forms of biomass would qualify as a renewable energy resource for REPS compliance purposes, and that those forms are those that are specifically enumerated in the statute and others not named that are ejusdem generis, or of the same kind, class or nature. In that case I dissented because I do not believe that wood chips derived from the harvesting of mature growth whole trees are either "agricultural waste, animal waste, wood waste, spent pulping liquors, combustible residues, combustible liquids, combustible gases, energy crops, or landfill methane." In this case, however, I believe that yard waste is a form of biomass that is ejusdem generis to those forms of biomass that are specifically enumerated in the statute, and for that reason, I concur in the decision reached by the majority.

DOCKET NO. P-100, SUB 110

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

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

BY THE COMMISSION: On December 13, 2010, 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 under G.S. 62-157(b) and (c) from $0.09 to $0.11. TRS enables an individual with a hearing or speech disability to communicate by telephone with a person without a hearing or speech disability. Under G.S. 62-157(b) and (c), the Commission requires 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." 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 DHHS. The funds collected from the access line surcharge are maintained in the TRS Fund. In addition to funding from access lines, TRP receives funding through a surcharge under G.S. 62-157, 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 based on the access line surcharge that is set by the Commission.

In addition to funding TRP, pursuant to S.L. 2009-451 (the 2009 Budget Bill), a significant part of the Wireless TRS Fund is also used to fund the Regional Resource Centers (Regional Centers) within the Division of Services for the Deaf and Hard of Hearing. According to DHHS, Regional 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. DHHS believes the budget landscape in 2009 led the General Assembly to assign all costs for the continued operation of the Regional Centers directly to receipts received from the Wireless TRS Fund to ensure that the telecommunications, wireless and emergency access needs of the deaf, hard of hearing and deaf-blind people would continue to be met.

The Commission set the current surcharge in a proceeding in 2007. On October 12, 2007, the Public Staff filed a Petition to Revise the Telecommunications Relay Surcharge and Reserve Margin in this docket. In that petition, the Public Staff reported that the TRS Fund and the Wireless TRS Fund had grown too large and recommended, among other things, a reduction in the access line surcharge from $0.11 to $0.09. On December 13, 2007, the Commission issued an Order decreasing the surcharge to $0.09 as recommended by the Public Staff.

In April 2009, the combined amount of the reserve (TRS Fund and Wireless TRS Fund) was approximately $16.6 million. According to the petition, on April 9, 2009, pursuant to Executive Order No. 6, Governor Perdue transferred $5 million from the Wireless TRS Fund to the General Fund to avoid a deficit in the General Fund due to the national economic slowdown. Then, pursuant to a provision enacted in the 2009 Budget Bill, an additional $4.5 million was transferred from the reserve (specifically, the TRS Fund) to the General Fund. The Budget Bill also directed DHHS to petition the Commission to reset the surcharge if, upon the transfer and appropriation of the TRS funds, the funds to maintain a reasonable margin for reserve for operation of the statewide telecommunications service were insufficient. Currently, the reserve margin is set at $6.5 million.

DHHS states in its petition that the reserve margin, as of the October 2010 budget report, is $4.3 million, below the $6.5 million set by the Commission. In addition, DHHS projects that the TRP will experience an annual shortfall of revenues versus expenditures of $2.0 million. Thus, DHHS states that the current surcharge can no longer support operational expenditures and must be increased to an amount that can sustain operations and restore the required $6.5 million reserve. Accordingly, DHHS requests an increase to $0.11 to allow for continued operations and to rebuild the reserve to the required amount.

The Public Staff presented this matter at the Commission's Regular Staff Conference on January 31, 2011. The Public Staff stated that it has reviewed the petition. Based on current expenditures and an analysis of projected access line and wireless line growth, the Public Staff believes that the $0.09 surcharge is not sufficient to support the operation of TRP and the Regional Centers and rebuild the reserve to the required $6.5 million and recommends approval of the increase to $0.11 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 $0.09 per access line to $0.11 per access line effective on April 1, 2011. The increase shall be reflected on customers' bills issued on or after April 1, 2011.

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, 2011 increase.

3. That local service providers may continue to retain $0.01 per access line, per month, of the TRS access line surcharge for collection, inquiry, and administrative expenses.

4. 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 2nd day of February, 2011.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Pb020111.02

APPENDIX A

NOTICE OF TELECOMMUNICATIONS RELAY SERVICE (TRS) SURCHARGE INCREASE

Effective with telephone bills issued on or after April 1, 2011, the Telecommunications Relay Service (TRS) surcharge is $0.11 per access line, per month. On _____________, 2011, the North Carolina Utilities Commission authorized an increase in the monthly TRS surcharge amount from $0.09 to $0.11 to maintain adequate funding for the Telecommunications Resource Program (TRP) and for Regional Resource Centers within the Division of Services for the Deaf and Hard of Hearing. 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 165a

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Implementation of Subsection (l)	)	ORDER ADDRESSING THE PUBLIC
Price Plans Pursuant to Senate	)	STAFF'S SUBSECTION (L) REPORT AND
Bill 343, Session Law 2011-52	)	ADOPTING AN AMENDED CLP
	)	CERTIFICATION APPLICATION FORM

BY THE COMMISSION: On April 26, 2011, Senate Bill 343 (SB 343), entitled "An Act Establishing the Communications Reform and Investment Act of 2011" became law (Session Law 2011-52), creating a new category of price plan under G.S. 62-133.5(l) (known as Subsection (l)) which any local exchange carrier (LEC) or competing local provider (CLP) may elect into by filing notice of its intent to do so with the Commission. The election is effective immediately upon filing.

On May 17, 2011, the Commission issued an Order Instituting Certain Filing Requirements and Requesting Comments for Subsection (l) electing carriers including election filing requirements and a methodology for assigning docket numbers. In addition, the Commission elected to freeze switched access charges for Subsection (l) electing carriers until such a time as a future proceeding establishes a new methodology for different rates. Finally, the Commission concluded that it should solicit from the Public Staff, after conferring with interested parties, its recommendations regarding statutes, Commission rules, and notice and reporting obligations that it believes will no longer be in force for a Subsection (l) electing company and the reasons therefore. The Commission invited all interested parties to comment on Ordering Paragraph Nos. 1 through 3 of its Order no later than June 15, 2011. No party filed comments on Ordering Paragraph Nos. 1 through 3 of the May 17, 2011 Order. Therefore, by this Order, the Commission adopts Ordering Paragraph Nos. 1 through 3 of the May 17, 2011 Order as final.

On September 6, 2011, the Public Staff filed its Report on its recommendations regarding statutes, Commission rules, and notice and reporting obligations that it believes will no longer be in force for a Subsection (l) electing company and the reasons therefore. As requested, the Public Staff conferred with the North Carolina Telecommunications Industry Association, Inc. (NCTIA) and counsel for the Competitive Carriers of the South, Inc. (CompSouth) regarding statutes, Commission rules, and notice and reporting obligations that it believes will no longer be in force for a Subsection (l) electing company. Using the format previously adopted for Subsection (h) electing carriers in its Report of Working Group, filed on February 2, 2010 in Docket No. P-100, Sub 165, the Public Staff prepared a matrix outlining the statutes, Commission rules, and notice and reporting obligations that could potentially be affected by SB 343, and an assessment of the impact. The Public Staff and the NCTIA are in agreement on all issues addressed in the matrix.[1] CompSouth was provided with the matrix, but later filed comments. On September 8, 2011, the Commission issued an Order seeking comments on the Public Staff's Report. CompSouth was the only party to file comments on the Public Staff's Report. On October 24, 2011, the Commission issued an Order seeking responses to CompSouth's comments from the Public Staff and any interested party.

COMPSOUTH'S COMMENTS

On October 3, 2011, CompSouth filed comments regarding the Public Staff Report. While not seeing any basis for the Commission to deviate from its previous general approach concerning the implementation of the recent retail deregulatory statutes, CompSouth offered several sets of comments.

The first was that the Commission has preserved authority over wholesale services. CompSouth did not disagree with this.

The second set of comments was more complicated. CompSouth noted that the Public Staff had recommended identical language in Item (iii) for Issues 23, 27, and 38. That language

[1] On September 8, 2011, the Public Staff filed a clarification with respect to Item 6 of the Matrix (G.S. 62-81, Special Procedure in Hearing and Deciding Rate Cases). The Public Staff noted that Item 6 indicated that the item was not affected by S.L. 2011-52, however, the item should have indicated that it was not applicable to Subsection (l) entities.

stated that "no constraints can be placed on the rates of the Subsection (l) company's services that were subject to full pricing as of the date of its election."[1] The Public Staff said that the justification for this recommended language is the new G.S. 62-133.5(l)(1)(c).[2] CompSouth characterized the new Item (iii) language as an interpretation of G.S. 62-133.5(l)(1)(c). The Public Staff, moreover, does not identify with specificity what rates are at issue. CompSouth's conclusion was that the statement seems to be in the nature of a declaratory ruling of unspecified scope and application.

To the extent that the Commission's Order in this proceeding will be taken as endorsing the various narrative statements in the report, CompSouth urged that the better course would be to either delete the language inserted into the Public Staff's Report or modify it consistent with the previous Commission Order interpreting Session Law 2009-238.[3] In the first place, CompSouth asserted that the interpretative language is not responsive to the specific issue—which is the applicability of the referenced regulatory requirements (i.e., G.S. 62-138, G.S. 62-148, and Rule R9-4) to Subsection (l)–electing entities. In addition, that statutory language, of course, speaks for itself; and CompSouth argued that a Commission order interpreting that language is beyond the scope of the instant proceeding, which is limited to identifying those regulatory requirements that are no longer applicable to Subsection (l)–electing companies. Should the statutory directive need interpretation, CompSouth argued that such interpretation is best addressed in the context of specific facts where the Commission is able to fully consider the impact of its conclusion.

The third set of comments of CompSouth was that AT&T has now achieved a greater degree of deregulation (as a Subsection (l) company) than the parties against which it competes. The Commission should re-examine the need for continued regulation of the retail services of competitive carriers. While the Commission has rejected this argument previously in the context of Subsection (h) implementation, the matter needs to be revisited.

NCTIA RESPONSE

On November 10, 2011, the NCTIA filed a Response to CompSouth's Comments. The NCTIA opposed the CompSouth suggestion that the Public Staff's Report should be consistent with the previous Subsection (h) Report Order. The NCTIA argued that this suggestion ignored the fact that the legislation which is the subject of this proceeding (SB 343) was the product of the General Assembly's actions taken *after* the Commission issued its March 30, 2010, Order Interpreting House Bill 1180 (HB 1180), S.L. 2009-238 in Docket No. P-100, Sub 165.

[1] Issue 23 relates to G.S. 62-138, Issue 27 relates to G.S. 62-148, and Issue 38 relates to Rule R9-4. These concern, respectively, the requirements to file rates, service regulations and contracts; rates on leased or controlled utility rates - retail; and the filing of telephone and telegraph tariffs and maps.

[2] G.S. 62-133.5(l)(1) reads in pertinent part: "(1) Beginning on the date the local exchange company's election under this subsection becomes effective, the Commission shall not... c. impose any tariffing requirements on any of the local exchange company's services that were not tariffed as of the date of the election, or impose any constraints on the rates of the local exchange company's services that were subject to full pricing flexibility as of the date of election."

[3] Order Concerning Working Group Report, Docket No. P-100, Sub 165, March 30, 2010 (involving implementation of Session Law 2010-238 concerning Subsection (h))(Report Order).

Moreover, on August 2, 2010, House Bill 466 (HB 466), S.L. 2010-173, "An Act to Amend the Consumer Choice and Investment Act of 2009" was signed by Governor Perdue. HB 466 included technical corrections to HB 1180 that directly impacted a number of the responses prepared by the working group in the Subsection (h) docket which were approved by the Commission in its March 30, 2010 Order (including Issues 23, 27, and 38). The relevant technical correction included the addition of a Subsection "c" to G.S. 62-133.5(h)(3).

That very same language was carried over into SB 343 in preparing G.S. 62-133.5(l)(1)(c) for Subsection (l) electing carriers. Thus, the current recommendations in the Public Staff's Subsection (l) Report accurately reflect the actions of the General Assembly since the Subsection (h) Report Order. The NCTIA also noted that the Commission continues to have authority under Subsection (l) as to the rates, terms, and conditions of wholesale services.

Lastly, the NCTIA noted that CompSouth had revived its previous arguments made in the Subsection (h) docket that CLPs should not be subject to any of the requirements set forth in Subsection (h) or (l), apparently wanting to avoid any regulation of any CLP retail service offerings. The Commission has always rejected this argument. The NCTIA view is that it was the intent of these various legislative actions to level the regulatory playing field between LECs and CLPs. The Commission's rejection of this line of argument by CompSouth is consistent with legislative intent.

PUBLIC STAFF RESPONSE

On November 10, 2011, the Public Staff filed its Response to CompSouth's Comments which focused on Issues 23, 27, and 38 in the present docket.[1] The Public Staff agreed that in the instant case each of those issues includes as Item (iii): "No constraints can be placed on the rates of the Subsection (l) company's services that were subject to full pricing as of the date of its election." The previous Subsection (h) Report Order, by contrast, included the following language with respect to these issues: "Tariffing of non-retail services that have been detariffed in accordance with an earlier regulatory plan will be addressed in future comments on non-retail regulation of Subsection (h) entities."

The Public Staff pointed out that the Subsection (h) Report Order language is not applicable to companies electing regulation under Subsection (l) since the imposition of tariffing requirements on any services that were not tariffed as of the date of the election is expressly prohibited by G.S. 62-133.5(l)(1)(c). It is also, for that matter, no longer applicable to companies electing regulation under Subsection (h), since the identical language prohibiting tariffing requirements was added as G.S. 62-133.5(h)(3)(c) in S.L. 2010-173 subsequent to the Report Order. Substantively, G.S. 62-133.5(l)(3)(c) also bars the Commission from imposing constraints on the rates of services of a Subsection (l) local exchange company that were subject to full pricing flexibility as of the date of the Subsection (l) election.

[1] The Public Staff noted that Issues 23, 27, and 38 of the matrices submitted in Docket No. P-100, Sub 165 concerning Subsection (h) and this proceeding concerning Subsection (l) are identical except for the language of Item (iii) under discussion here.

The Public Staff stated that its intention in proposing the language set forth in Item (iii) of Issues 23, 27, and 38 was simply to incorporate this portion of G.S. 62-133.5(l)(1)(c). The Public Staff stated that it agrees with CompSouth that the statute speaks for itself, but disagrees with CompSouth's assertion that including the statutory language should be construed as a declaratory ruling.

The Public Staff further noted that another concern expressed by CompSouth was the continued application of regulatory requirements, such as service quality and billing and collection rules, to CLPs, while LECs may elect a form of alternative regulation (Subsection (h) or Subsection (l)) that exempts them from those rules. CompSouth asked the Commission to reconsider its decision in Docket No. P-100, Sub 165, which rejected CompSouth's request to consider the alteration of the regulation of retail services of CLPs.

The Public Staff responded that the Commission should take the same position in this docket as it did previously. The advantages offered to LECs under Subsection (l) are available to any LEC and any CLP, conferring thereby the same degree of deregulation on CLPs as on LECs. G.S. 62-133.5(h) and (l) were enacted to promote a "level playing field" with respect to the treatment of all local exchange companies. Hence, there is no reason to alter the regulation of retail services of CLPs beyond the options available to all local exchange companies under Subsections (h) and (l).

WHEREUPON, the Commission reaches the following

CONCLUSIONS

After careful consideration, the Commission concludes that good cause exists to adopt the Public Staff Matrix attached to the Public Staff's September 6, 2011, Report, subject to the amendment proposed in the Public Staff's September 8, 2011 letter, with reference to Item 6 (G.S. 62-81: Special Procedure in Hearing and Deciding Rate Cases)—namely, that the wording "Not Affected by S.L. 2011-52" is replaced by the wording "Not applicable to Subsection (l) entities." This amended matrix which is adopted herein is attached as Appendix A.

With respect to the comments of CompSouth, the Commission concurs with the Public Staff's analysis—and that of the NCTIA along the same lines. That is, in proposing the language set forth in Item (iii) of Issues 23, 27, and 38, the purpose was to incorporate the portion related to G.S. 62-133.5(l)(1)(c) regarding the imposition of tariff requirements. The Commission also concurs with the Public Staff that including the statutory language with reference to this item should not be construed as a declaratory ruling.

In addition, the Commission concurs with the Public Staff's and the NCTIA's view that those CLPs that desire to be freed of what they view to be an inordinate degree of regulation have a simple recourse, since they, too, can easily adopt Subsection (h) or Subsection (l) regulation.

Finally, as noted in Item 56 of the Matrix concerning Rule R17-2(f), the Commission needs to amend the CLP application for a certificate of public convenience and necessity so that, if desired, a CLP can file an application for certification and Subsection (l) election at the same time. Attached hereto as Appendix B is an amended CLP application form.

IT IS, THERFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 22nd day of November, 2011.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

bp112111.01

APPENDIX A
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	NCUC RULE/STATUTE OR OTHER	Description:		Public Staff and NCTIA Position
1	*G.S. 62-35(c)*	*System of Accounts - Depreciation*		Not applicable to Subsection (l) entities.
2	*G.S. 62-45*	*Determination of Cost and Value of Utility Property*		Not applicable to Subsection (l) entities.
3	*G.S. 62-51*	*To Inspect Books and Records of Corporations Affiliated with Public Utilities*		Not applicable to Subsection (l) entities.
4	*G.S. 62-73*	*Complaints*		Not applicable to retail services offered by Subsection (l) entities.
5	*G.S. 62-73.1*	*Complaints*		(i) Public Staff and Commission have authority under this section to determine if actions of Subsection (l) entities are reasonable. (ii) Subsection (l) entities are required to provide customers with contact information per the language of the statute.
6	*G.S. 62-81*	*Special Procedure in Hearing and Deciding Rate Cases*		Not Applicable to Subsection (l) entities.
7	*G.S. 62-110*	*Certification Requirements for Long Distance Providers, Payphone Service Providers, STS and Other Providers*		Not Affected by S.L. 2011-52.
8	*G.S. 62-110(f1) and P-100, Sub 133*	*Arbitrations and Interconnection Agreements*		Not Affected by S.L. 2011-52.
9	*G.S. 62-110(f1)*	*Universal Service*		Not Affected by S.L. 2011-52.
10	*G.S. 62-110(f4), (f5), (f6) and P-100, Sub 152b*	*Carrier of Last Resort (COLR) obligations and COLR Relief Report*		Subsection (l) entities do not have carrier-of-last-resort (COLR) obligations under state law, but may continue to have ETC obligations under federal law.
11	*G.S. 62-111*	*Transfers of Franchises; Mergers, Consolidations and Combinations of Public Utilities*		Not applicable to Subsection (l) entities.
12	*G.S. 62-118*	*Abandonment or Reduction of Service*		(i) Not applicable to retail services offered by Subsection (l) entities. (ii) Applicable to non-retail services of Subsection (l) entities.
13	*G.S. 62-130*	*Commission to Make Rates for Public Utilities; Customer Refunds*		Not applicable to Subsection (l) entities.
14	*G.S. 62-131*	*Rates Must be Just and Reasonable; Service Efficient*		Not applicable to Subsection (l) entities.

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	NCUC RULE/STATUTE OR OTHER	Description:		Public Staff and NCTIA Position
15	*G.S. 62-132*	*Rates Established under this Chapter Deemed Just and Reasonable; Remedy for Collection of Unjust or Unreasonable Rates*		Not applicable to Subsection (l) entities.
16	*G.S. 62-133*	*Establishment of Rates*		Not applicable to Subsection (l) entities.
17	*G.S. 62-133.5(f)*	*Retail Promotions*		Not applicable to retail services offered by Subsection (l) entities.
18	*G.S. 62-133.5(g)*	*Price Regulation Exemptions*		Applies to Subsection (l) entities.
19	*G.S. 62-134*	*Change of Rates; Notice; Suspension and Investigation*		Not applicable to Subsection (l) entities.
20	*G.S. 62-135*	*Temporary Rates Under Bond*		Not applicable to Subsection (l) entities.
21	*G.S. 62-136*	*Investigation of Existing Rates, Changing Unreasonable Rates, etc.*		Not applicable to Subsection (l) entities.
22	*G.S. 62-137*	*Scope of Rate Case*		Not applicable to Subsection (l) entities.
23	*G.S. 62-138*	*Utilities to File Rates; Service Regulations and Service Contracts with Commission*		(i) Not applicable to retail services offered by Subsection (l) entities. (ii) Applicable only to currently tariffed non-retail services of Subsection (l) entities. (iii) No constraints can be placed on the rates of the Subsection (l) company's services that were subject to full pricing as of the date of its election.
24	*G.S. 62-139*	*Rates Varying from Schedule Prohibited; Refunding Overcharges; Penalty*		Not applicable to Subsection (l) entities.
25	*G.S. 62-140*	*Nondiscrimination*		Not applicable to retail services offered by Subsection (l) entities.
26	*G.S. 62-142*	*Contracts as to Rates - Retail*		Not applicable to Subsection (l) entities.
27	*G.S. 62-148*	*Rates on Leased or Controlled Utility - Retail*		(i) Not applicable to retail services offered by Subsection (l) entities. (ii) Applicable only to currently tariffed non-retail services of Subsection (l) entities. (iii) No constraints can be placed on the rates of the Subsection (l) company's services that were subject to full pricing as of the date of its election.
28	*G.S. 62-153*	*Contracts of Public Utilities*		Not applicable to Subsection (l) entities.
29	*G.S. 62-300, 62-302, R15-1 and M-100, Sub 118*	*Fees and Charges Including Regulatory Fee*		Will apply to Subsection (l) entities.

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	NCUC RULE/STATUTE OR OTHER	Description:		Public Staff and NCTIA Position
30	*G.S. 62-310*	*Violations*		(i) Not applicable to retail services offered by Subsection (l) entities. (ii) Applicable to non-retail services of Subsection (l) entities.
31	*R1-15*	*Investigation and Suspension Proceedings*		(i) Not applicable to retail services offered by Subsection (l) entities. (ii) Applicability to non-retail services will be addressed in future proceedings.
32	*R1-17*	*Filing of Increased Rates*		(i) Not applicable to retail services offered by Subsection (l) entities. (ii) Applicability to non-retail services will be addressed in future proceedings.
33	*R1-18*	*Reparations and Undercharges*		(i) Not applicable to retail services offered by Subsection (l) entities. (ii) Applicability to non-retail services will be addressed in future proceedings.
34	*R1-32, R9-9*	*Form M report & other financials*		(i) Public LECs and CLPs should provide link to SEC filings on an annual basis. (ii) Non-public LECs and CLPs should submit audited financials on an annual basis.
35	*R9-1*	*Safety Rules and Regulations*		Not Affected by S.L. 2011-52.
36	*R9-2*	*Uniform System of Accounts (USOA)*		Subsection (l) entities should be exempted.
37	*R9-3*	*Annual Filing of Construction Plans and Objectives*		Rescinded by Commission Order in Docket Nos. P-100, Sub 19 and P-100, Sub 168.
38	*R9-4*	*Telephone and Telegraph Tariffs and Maps – Retail*		(i) Not applicable to retail services offered by Subsection (l) entities. (ii) Applicable only to currently tariffed non-retail services of Subsection (l) entities. (iii) No constraints can be placed on the rates of the Subsection (l) company's services that were subject to full pricing as of the date of its election. (iv) ILEC boundary maps should continue to be filed.
39	*R9-5 and P-100, Sub 142, Sub 150 and Sub 153*	*N11 Services and Tariffs except 711*		Only rules and Orders relating to 711 service will be applicable to Subsection (l) entities.
40	*R9-6, P-100, Sub 133f*	*Lifeline/Linkup Service, Reports and Tariffs, Lifeline Toll Restriction*		Not Affected by S.L. 2011-52.
41	*R9-7*	*Extended Area Service*		Not applicable to Subsection (l) entities.
42	*R9-8 and P-100, Sub 99*	*Service Quality and Service Quality Results Reports*		Not applicable to Subsection (l) entities.

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	NCUC RULE/STATUTE OR OTHER	Description:		Public Staff and NCTIA Position
43	*R12-1*	*Deposit Policy - Declaration of Public Policy*		Not applicable to Subsection (l) entities.
44	*R12-2*	*Establishment of Credit for Consumers*		Not applicable to Subsection (l) entities.
45	*R12-3*	*Reestablishment of Service for Consumers*		Not applicable to Subsection (l) entities.
46	*R12-4*	*Deposit and Interest on Deposits*		Not applicable to Subsection (l) entities.
47	*R12-5*	*Deposit Refund Policy*		Not applicable to Subsection (l) entities.
48	*R12-6*	*Deposit Records*		Not applicable to Subsection (l) entities.
49	*R12-7*	*Appeal by Applicant or Customer in Connection with Billing Decisions*		Not applicable to Subsection (l) entities.
50	*R12-8*	*Discontinuance of Service for Nonpayment*		Not applicable to Subsection (l) entities.
51	*R12-9*	*Uniform Billing Procedure*		Not applicable to Subsection (l) entities.
52	*R12-12*	*Definitions*		Not applicable to Subsection (l) entities.
53	*R12-14*	*Advertising by Telephone Companies*		Not applicable to Subsection (l) entities.
54	*R12-16*	*Bill inserts - Costs shall not be passed to Customers*		Not applicable to Subsection (l) entities.
55	*R12-17*	*Disconnection, Denial and Billing of Telephone Service*		Not applicable to Subsection (l) entities.
56	*R17-2(f)*	*Requirements and Limitations Regarding Certification of Competing Local Providers (Access to services and compliance with rules)*		(i) Rule R17-2(f)(1-3 and 5-7) are not applicable to Subsection (l) entities. (ii) Rule R17-2(f)(4 and 8) are unaffected by S.L. 2011-52. (iii) Rule R17-2(f)(2) requirement for CLPs to provide directories should not be applicable in areas where ILEC is Subsection (l) company and no longer has requirement to publish directory. (iv) Commission should amend CLP application form so that, if desired, a CLP can file an application for certification and Subsection (l) election at the same time.
57	*R17-2(g)*	*Requirements and Limitations Regarding Certification of Competing Local Providers (Access to services and compliance with rules)*		Not applicable to Subsection (l) entities.
58	*R17-2(i)*	*Requirements and Limitations Regarding Certification of Competing Local Providers (Access to services and compliance with rules)*		Subsection (l) entities should be exempted.

	NCUC RULE/STATUTE OR OTHER	Description:		Public Staff and NCTIA Position
59	*R17-2(j)*	*Requirements and Limitations Regarding Certification of Competing Local Providers (Access to services and compliance with rules)*		Not applicable to retail services offered by Subsection (l) entities.
60	*R17-2(k)*	*Requirements and Limitations Regarding Certification of Competing Local Providers (Access to services and compliance with rules)*		Access line information should be filed pursuant to the Commission Order issued June 30, 2011 in Docket No. P-100A, Sub 133.
61	*R17-2(l)*	*Requirements and Limitations Regarding Certification of Competing Local Providers (TRS and G.S. 62-157)*		Not Affected by S.L. 2011-52.
62	*R17-2(m)*	*Requirements and Limitations Regarding Certification of Competing Local Providers (Adherence to Chapter 62A)*		Not Affected by S.L. 2011-52.
63	*R17-2(n)*	*Requirements and Limitations Regarding Certification of Competing Local Providers (Compliance with Rule R12-17)*		Not applicable to Subsection (l) entities.
64	*R17-2(p)*	*Requirements and Limitations Regarding Certification of Competing Local Providers (Billing of third party services)*		Not applicable to Subsection (l) entities.
65	*R17-2(q)*	*Requirements and Limitations Regarding Certification of Competing Local Providers (Rate increase notice)*		Not applicable to Subsection (l) entities.
66	*R17-2(r)*	*Requirements and Limitations Regarding Certification of Competing Local Providers (Billings for pay-per-call services)*		Not applicable to Subsection (l) entities.
67	*R17-2(s)*	*Requirements and Limitations Regarding Certification of Competing Local Providers (Timing of calls)*		Not applicable to Subsection (l) entities.
68	*R17-2(t)*	*Requirements and Limitations Regarding Certification of Competing Local Providers (Compliance with R13)*		Not Affected by S.L. 2011-52.
69	*R17-2(u)*	*Requirements and Limitations Regarding Certification of Competing Local Providers (Regulatory Fee)*		Not Affected by S.L. 2011-52.

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	NCUC RULE/STATUTE OR OTHER	Description:		Public Staff and NCTIA Position
70	*R17-2(v)*	*Requirements and Limitations Regarding Certification of Competing Local Providers (Service provided in unlawful manner)*		Not Affected by S.L. 2011-52.
71	*R17-2(w)*	*Requirements and Limitations Regarding Certification of Competing Local Providers (Penalty for disconnection)*		Not applicable to Subsection (l) entities.
72	*R17-6(a)*	*Prepaid Local Exchange Service (Exemptions from Rule R17-2(f))*		The only exemption still applicable to Subsection (l) entities is the exemption from R17-2(f)(4) found in R17-6(a)(3).
73	*R17-6(b)*	*Prepaid Local Exchange Service (Terms and Conditions for service)*		Not applicable to Subsection (l) entities except for R17-6(b)(1)(iv).
74	*R17-6(c)*	*Prepaid Local Exchange Service (Customer Service Agreement)*		Not applicable to Subsection (l) entities.
75	*R17-7*	*Dialing Parity*		Not Affected by S.L. 2011-52.
76	*R20-1(a)(b)(e)*	*Slamming - Marketing Activity Regulations other than Federal Requirements*		Not Affected by S.L. 2011-52.
77	*R20-1(d)*	*Cramming*		Not applicable to Subsection (l) entities.
78	*R20-2*	*Fair Competition Among Local Providers*		Not Affected by S.L. 2011-52.
79	*R21-1*	*Discontinuance or Reduction of Telecommunications Services - Application*		(i) Not applicable to retail services offered by Subsection (l) entities. (ii) Applicable to non-retail services of Subsection (l) entities.
80	*R21-2*	*Discontinuance or Reduction of Telecommunications Services By LECs and CLPs*		(i) Not applicable to retail services offered by Subsection (l) entities. (ii) Applicable to non-retail services of Subsection (l) entities.
81	*R21-3*	*Bankruptcy*		(i) Not applicable to retail services offered by Subsection (l) entities. (ii) Applicable to non-retail services of Subsection (l) entities.
82	*R21-4*	*Termination of Service to CLPs by Underlying Carriers*		(i) Applies to underlying carrier providing service to CLP. (ii) Will not apply to CLP discontinuing service that has no COLR obligation. (iii) Company with COLR obligation will have to notify Commission.
83	*HB1180*	*Annual Report of Company Operations*		Not applicable to Subsection (l) entities on and after the third anniversary following the date of the LEC's election.
84	*HB1180*	*Monitoring Compliance with GDPPI*		Not applicable to Subsection (l) entities.

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	NCUC RULE/STATUTE OR OTHER	*Description:*		Public Staff and NCTIA Position
85	*HB1180*	*Public Staff Shall Keep Records of All Complaints*		(i) Public Staff is to maintain record of all complaints and status of resolution. (ii) Inform customer that complaints can be referred to Commission.
86	*P-100, Subs 65 and 72*	*ITORP and Associated Tariffs and Intercarrier Compensation*		Not Affected by S.L. 2011-52.
87	*Price Reg Dockets*	*Price Reg Annual Filing for Regulated Services*		(i) Not applicable to retail services offered by Subsection (l) entities. (ii) Applicability to non-retail services will be addressed in future proceedings.
88	*Standing Data Request*	*Central Office Equipment Report*		Information will be supplied in the event of a Commission or Public Staff request.
89	*Tariff Requirement*	*White Pages Directories*		Requirement to publish white pages directories not applicable to Subsection (l) entities.
90	*Price Reg Dockets*	*Price Reg Reports - Monthly*		(i) Not applicable to retail services offered by Subsection (l) entities. (ii) Applicability to non-retail services will be addressed in future proceedings.
91	*P-55, Sub 1013*	*Price Reg Service List Report - AT&T Only*		Report has been terminated.
92	*Commission Memo*	*Station Development Report*		Access line information should be filed pursuant to the Commission Order issued June 30, 2011 in Docket No. P-100A, Sub 133.

APPENDIX B

APPLICATION FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO OFFER LOCAL EXCHANGE AND EXCHANGE ACCESS TELECOMMUNICATIONS SERVICE AS A COMPETING LOCAL PROVIDER

To Be Completed by Chief Clerk:
DOCKET No. P-______, Sub _____
Filing Fee Received $__________

Note: To apply for a Competing Local Provider (CLP) Certificate, Applicant must submit a filing fee of $250.00, payable to N.C. Department of Commerce/Utilities Commission, and the typed original and 9 copies of this document to the North Carolina Utilities Commission at the following address:

Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4325

The application must be properly completed and correctly verified. If it is not, a copy of the application will be returned to the Applicant, and the application will not be further processed. If the Applicant wishes to continue with the certification process, a correct application must be resubmitted with a new filing fee. The original filing fee will not be returned.

A copy of the completed application must be served on each incumbent Local Exchange Company (LEC) in North Carolina. A service list may be obtained from the Chief Clerk.

Any information which the Applicant claims is "confidential" or constitutes a "trade secret" should be clearly marked as such and filed under "SEAL." Two copies of the confidential information should be provided.

Falsification of or failure to disclose any information in this application for certification may be grounds for denial of or delay in the award of the certificate requested.

GENERAL ORDERS – TELECOMMUNICATIONS

The undersigned certifies to the North Carolina Utilities Commission as follows:

NAME AND CONTACTS

1. **APPLICANT**

____
(NAME)

____
(PHYSICAL ADDRESS - STREET, SUITE NUMBER, CITY, STATE, ZIP)

____
(MAILING ADDRESS - IF DIFFERENT FROM ABOVE)

____
(d/b/a NAME(S))

FOR: QUESTIONS ON THE APPLICATION

____
(NAME- PRINTED OR TYPED)

____
(PHYSICAL ADDRESS - STREET, SUITE NUMBER, CITY, STATE, ZIP)

____
(MAILING ADDRESS - IF DIFFERENT FROM ABOVE)

____
(EMAIL ADDRESS)

____
(TELEPHONE NUMBER) (FACSIMILE NUMBER)

FOR: GENERAL REGULATORY MATTERS

____
(NAME- PRINTED OR TYPED)

____
(PHYSICAL ADDRESS - STREET, SUITE NUMBER, CITY, STATE, ZIP)

____
(MAILING ADDRESS - IF DIFFERENT FROM ABOVE))

____
(EMAIL ADDRESS)

____
(TELEPHONE NUMBER) (FACSIMILE NUMBER)

GENERAL ORDERS – TELECOMMUNICATIONS

FOR: COMPLAINT INQUIRIES BY COMMISSION

(NAME- PRINTED OR TYPED)

(PHYSICAL ADDRESS - STREET, SUITE NUMBER, CITY, STATE, ZIP)

(MAILING ADDRESS - IF DIFFERENT FROM ABOVE)

(EMAIL ADDRESS)

(TELEPHONE NUMBER) (FACSIMILE NUMBER)

FOR: REGULATORY FEE PAYMENT

(NAME- PRINTED OR TYPED)

(PHYSICAL ADDRESS - STREET, SUITE NUMBER, CITY, STATE, ZIP)

(MAILING ADDRESS - IF DIFFERENT FROM ABOVE)

(EMAIL ADDRESS)

(TELEPHONE NUMBER) (FACSIMILE NUMBER)

FOR: RESPONSIBILITY FOR NORTH CAROLINA OPERATIONS

(NAME- PRINTED OR TYPED)

(PHYSICAL ADDRESS - STREET, SUITE NUMBER, CITY, STATE, ZIP)

(MAILING ADDRESS - IF DIFFERENT FROM ABOVE)

(EMAIL ADDRESS)

(TELEPHONE NUMBER) (FACSIMILE NUMBER)

GENERAL ORDERS – TELECOMMUNICATIONS

FOR: CONTACT BY POTENTIAL RESIDENTIAL SUBSCRIBERS

(NAME- PRINTED OR TYPED)

(PHYSICAL ADDRESS - STREET, SUITE NUMBER, CITY, STATE, ZIP)

(MAILING ADDRESS - IF DIFFERENT FROM ABOVE)

(EMAIL ADDRESS)

(TELEPHONE NUMBER) (FACSIMILE NUMBER)

FOR: CONTACT BY POTENTIAL BUSINESS SUBSCRIBERS (IF DIFFERENT FROM RESIDENTIAL)

(NAME- PRINTED OR TYPED)

(PHYSICAL ADDRESS - STREET, SUITE NUMBER, CITY, STATE, ZIP)

(MAILING ADDRESS - IF DIFFERENT FROM ABOVE)

(EMAIL ADDRESS)

(TELEPHONE NUMBER) (FACSIMILE NUMBER)

FOR: BILLING FOR PSP LINES AND PSP NOTICE REQUIREMENTS

Complete only if the Applicant intends to provide pay telephone service as a Payphone Service Provider (PSP). Provide the information to be used by the serving CLP or local exchange company (LEC) in billing for PSP lines or trunks and by the Applicant in meeting PSP notice requirements:

((NAME- PRINTED OR TYPED)

(PHYSICAL ADDRESS - STREET, SUITE NUMBER, CITY, STATE, ZIP)

(MAILING ADDRESS - IF DIFFERENT FROM ABOVE)

(EMAIL ADDRESS)

(TELEPHONE NUMBER) (FACSIMILE NUMBER)

GENERAL ORDERS – TELECOMMUNICATIONS

IDENTITY AND BUSINESS STRUCTURE

2. Type of Organization: (Check as appropriate)

LLC	__	Individual (sole proprietor)	
Partnership	__	Limited Partnership (LP)	
Corporation	__	Public __ Private __ S	__ C

Other: Please Specify

3. Provide the information as specified below for the specific type of organization identified in Item 2.

   a) If a limited liability company, attach a copy of the articles of organization and the operating agreement, marked **Exhibit A.** Also attach a list of members, marked **Exhibit B.** If Applicant was not organized in North Carolina, attach a copy of the certificate of authority to do business in North Carolina, issued by the Secretary of State, marked **Exhibit C.**

   b) If a partnership or limited partnership, attach a copy of the partnership agreement, marked **Exhibit A.** Also attach a list of partners and officers and the percentage of equity interest of each, marked **Exhibit B,** and give names, positions and addresses of the principal officers.

   c) If a corporation, attach copy of the articles of incorporation and all amendments, if any, marked **Exhibit A.** Also attach a list of all directors and principal stockholders with the number of shares held by each, marked **Exhibit B,** and give names, positions and addresses of the principal corporate officers.

   d) If a corporation, state and date of incorporation: State: __ Date: _______. If Applicant was not organized in North Carolina, attach a copy of the certificate of authority to do business in North Carolina, issued by the Secretary of State, marked **Exhibit C.**

4. If an office is not maintained in North Carolina, please provide the name and address of Applicant's agent for service of process in North Carolina.

1. If any individuals, directors, partners, officers, or members are affiliated with (i.e., own at least a 10% interest in or serve as directors, partners, or members of) any other telecommunications company, provide, as **Exhibit D,** a list of the company(ies) and a description of the affiliation.

6. If the Applicant has a parent, affiliate(s) or subsidiary(ies), provide an organizational chart as **Exhibit E** which identifies each entity and its relationship to the Applicant.

FINANCIAL CAPABILITY

7. Provide an SEC 10K or audited financial statements for the most recent twelve months, marked as **Exhibit F.** If neither is available, provide Items (a) and (b) below. Item (c) must be provided if the Applicant is relying on a parent company or equity partner for its financial resources.

   a) Provide a current Balance Sheet, marked as **Exhibit F.**

   b) Provide an Income Statement, marked as **Exhibit F,** reflecting current and prior year balances for the twelve months ended as of the date of the Balance Sheet, or, if more readily available, for the period since the close of the preceding calendar year.

   c) Provide the parent company's or equity partner's financial information as listed in this item (SEC 1 0K or audited financial information; or balance sheet and income statement), marked as **Exhibit F1** or **Exhibit F2** and **F3,** respectively, and a letter of commitment, marked as **Exhibit F4,** signed by an officer of the parent company or equity partner.

8. If the information in Item 7 is not available, please provide the information below. Applicants may file the appropriate portions of their plans and forecasts if they are sufficiently similar to the items below rather than generating new documents.

   a) Annual projected income statement and statement of projected cash flows for each year until net cash is provided by the operating activities of the applicant or three years, whichever period is longer, as **Exhibit G1.**

   b) Detailed description of the assumptions for each item reflected in the projected income statement and cash flow statement. The description should provide information on key assumptions, including, but not limited to: number of customers, payroll costs, the number of persons employed (including independent contractors), and sources of external funds (banks, investors) as **Exhibit G2.**

   c) Narrative description of the applicant's plan(s) for achieving the projected cash flow amounts set forth in the statement of projected cash flows above as **Exhibit G3.**

   d) Commitment letters, letters of intent, etc. from lenders and investors to provide funds through the first 12 months of operations as **Exhibit G4.**

EXPERIENCE AND MANAGERIAL CAPABILITY

9. a. Please list all states in which the Applicant or any of its affiliates have been authorized to operate and the name under which authority is held, and describe the services offered in those states.

b. Please list all states in which the Applicant or any of its affiliates have been denied authority to operate, and the name under which authority was held or requested, and explain the reason for such denial.

c. Please list all instances in which the Applicant has been penalized for slamming, cramming or providing inadequate service and explain each instance.

d. If the Applicant is a newly created entity, list the experience of each principal officer, manager, or managing partner and provide other documentation in order to show that person's managerial and technical ability to provide services. Mark this documentation as **Exhibit H.**

PROPOSED SERVICE

10. Please described the proposed geographic area or areas to be served.

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11. Please state the types of local exchange and exchange access services to be provided.

COMPLIANCE

12. Yes [ ] No [ ] In accordance with Commission Rule R17-2((b)(7), has the application been served on each of the LECs that provide local exchange service in North Carolina?

13. In accordance with Commission Rule R17-2(f), is the Applicant willing, either directly or through arrangements with other carriers, to provide as a condition to certification:

a) Yes [ ] No [ ] Access to emergency service and access to services for the hearing and speech impaired?

b) Yes [ ] No [ ] Access to local and long distance directory assistance and provision of local telephone directories to end-users?

c) Yes [ ] No [ ] Access to operator services?

d) Yes [ ] No [ ] Access to all standard dialing patterns to all interLATA and intraLATA long distance carriers, including 1+ and 0+ access to the customer's carrier of choice for interLATA and intraLATA long distance calls, using a full 2-PIC methodology, as further described in 47 CFR 51.209 and Commission Rule R17-7?

e) Yes [ ] No [ ] Compliance with basic service standards as defined in any applicable rules and decisions of the Commission?

f) Yes [ ] No [ ] Free blocking of 900- and 976-type services and other pay-per-call services, including but not limited to calls to 700 and 800 numbers, for which charges are made by the service provider and billed by the Applicant?

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g) Yes [ ] No [ ] Free per-call and per-line blocking in accordance with the Orders of the Commission applicable to LECs, and to advise subscribers by insert or direct mailing of the availability of these free features at least once per year?

h) Yes [ ] No [ ] Number portability where technically and economically feasible?

14. Yes [ ] No [ ] Does the Applicant intend to offer prepaid local exchange service as defined by the Commission in R17-1, either now or in the future? If yes, please answer questions 14(a) through 14(b).

a) Yes [ ] No [ ] Does the Applicant understand and agree to the terms and conditions specified in Commission Rule R17-6 in the provision of prepaid local exchange service?

b) Yes [ ] No [ ] Does the Applicant understand that the exemption from a portion of the requirements of Commission Rule R17-2(f) would apply only in the provision of prepaid local exchange service(s), and that the Applicant must abide by all parts of Commission Rule R17-2(f) in the provision of any other basic local exchange service(s)?

15. Yes [ ] No [ ] Does the Applicant agree to abide by all applicable statutes, and all applicable Orders, rules and regulations entered and adopted by the North Carolina Utilities Commission?

16. Yes [ ] No [ ] Does the Applicant plan to employ agents of any type, including independent sales agents, in offering its intrastate services? If yes, please answer questions 16(a) and 16(b).

a) Yes [ ] No [ ] Does the Applicant understand that its agents must make it clear to prospective customers that they are only marketing the Applicant's services rather than offering service themselves?

b) Yes [ ] No [ ] Does the Applicant understand it is responsible for ensuring that its agents comply with the Commission's rules and regulations?

17. Yes [ ] No [ ] Does the Applicant agree to provide support for universal service in a manner determined by the Commission?

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18. Yes [ ] No [ ] Does the Applicant understand and agree to abide by Commission Rule R9-8 and Commission Rules R12-1 through R12-9?

19. Yes [ ] No [ ] Does the Applicant agree to maintain its books of account in accordance with Generally Accepted Accounting Principles (GAAP)?

20. Yes [ ] No [ ] Does the Applicant agree to file by the 15th day of each month a report with the Chief Clerk of the North Carolina Utilities Commission reflecting the total number of local access lines subscribed to at the end of the preceding month, listing separately for business and residential service, the number of local access lines that are providing prepaid local exchange service and the number of lines providing traditional local exchange telephone service in each respective geographic area that the Applicant serves?

21. Yes [ ] No [ ] Does the Applicant agree to participate in the telecommunications relay service in accordance with G.S. 62-157 and applicable orders, rules and regulations entered and adopted by the Commission?

22. Yes [ ] No [ ] Does the Applicant agree to be subject to the provisions of Chapter 62A of the General Statutes, the Public Safety Telephone Act, regarding emergency 911 service, applicable to service providers?

23. Yes [ ] No [ ] Does the Applicant understand and agree to abide by all applicable provisions adopted by the Commission for disconnection, partial payments, global toll denial, nonregulated charges, 900 and similar charges, treatment of stale debts, and disconnect notices and billing statements, as set forth in Commission Rule R12-17?

24. Yes [ ] No [ ] Does the Applicant agree to offer billing services for intrastate long distance calls only to long distance carriers certified by the Commission or to clearinghouses acting on behalf of certified long distance carriers? Please note that the name of the service provider shall be clearly stated on each page of the bill, and a contact telephone

number for questions on the service shall appear on the bill. If billing is done through a clearinghouse, the name of the clearinghouse shall also appear on each page of the bill.

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25. Yes [ ] No [ ] Will the Applicant give a notice by bill insert or direct mailing to all affected customers at least 14 days before any public utility rates are increased and before any public utility service offering is discontinued? Please note that notice of a rate increase shall include, at a minimum, the effective date of the rate change, the existing rates and the new rates.

26. Yes [ ] No [ ] Does the Applicant agree not to apply usage charges and per-call rates for switched local exchange services unless the call is answered? Please note that timing of a call shall not begin until the call is answered and shall end when either the calling party or the answering party disconnects.

27. Yes [ ] No [ ] Does the Applicant intend to offer pay telephone service? If so, please note that the provisions of Commission Rule R13, with the exception of Commission Rule R13-3(a), (b) and (c), shall apply to the offering of pay telephone service by a CLP. A CLP has the authority by virtue of its CLP certificate to offer both non-automated collect and automated collect service under the provisions of Commission Rule R13. When the term COCOT or PSP Certificate Number is referred to in Commission Rule R13, the docket number in which the CLP was certified shall be utilized, and when the term COCOT certificate, PSP certificate, or certificate, is referred to in Commission Rule R13, the CLP certificate shall be used.

28. Yes [ ] No [ ] Does the Applicant agree to be responsible for payment of the regulatory fee in accordance with G.S. 62-302 and Commission Rule R15?

29. Yes [ ] No [ ] Does the Applicant agree to notify the Commission, of any change in its (1) address, either physical or mailing, (2) Commission contacts, or (3) name under which the Applicant does business (d/b/a) within thirty (30) days of the effective date of any such change by mailing a notice of such change to the address shown on page 1 of this application?

30. Yes [ ] No [ ] Does the Applicant elect regulation under G.S. 62-133.5(h)? If so, the Applicant must comply with the "CERTAIN SUBSECTION (H) REQUIREMENTS AFTER SESSION LAW 2010-173" as set forth in Appendix B of the Commission's August 5, 2010 Order in Docket No. P-100, Sub 165.

31. Yes [ ] No [ ] Does the Applicant elect regulation under G.S. 62-133.5(l)? If so, the Applicant must comply with the requirements outlined in

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the Commission's May 17, 2011 Order in Docket No. P-100, Sub 165a.

______________________________	______________________________
(SIGNATURE)	(TITLE)
______________________________	______________________________
(NAME - PRINTED OR TYPED)	(DATE)

VERIFICATION

STATE OF ______________________ COUNTY OF ______________________

______________________________, personally appeared before me this day and, being first duly sworn, says that the facts stated in the foregoing application and any exhibits, documents, and statements thereto attached are true as he or she believes.

WITNESS my hand and notarial seal, this ________ day of ______________, 20___.

My Commission Expires: ____________________

____

Signature of Notary Public

____

Name of Notary Public – Type or Printed

Note to Notary: See verification requirements under "Completing the CLP Application" on the next page.

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COMPLETING THE CLP APPLICATION

1. This application is to be used to apply for a Certificate of Public Convenience and Necessity from the North Carolina Utilities Commission which, when granted, will authorize the holder to provide local exchange and local exchange access services as a **Competing Local Provider (CLP)** in the State of North Carolina. Applications for authority to provide other types of service must be filed in accordance with other Commission regulations.

2. The spaces in the shaded block on page 1 will be completed by the Chief Clerk when the application is received at the Commission's offices. The remainder of the application is to be completed by the Applicant and verified before a notary public.

3. **Company Identity.**

(a) The name of the Applicant must be the real name, as distinguished from a trade name or assumed name (d/b/a), of the individual, partnership, limited liability company or corporation applying for certification. If the Applicant is operating or intends to operate under a d/b/a in North Carolina, that name should also be provided in this application.

(b) If the Applicant intends to operate under a name other than the exact name that appears on the partnership agreement, articles of organization, articles of incorporation, or a name other than its real name, this must be a name that has been certified according to G.S. 66-68.

4. **Signature.**

This block in the verification is for the signature of the Applicant's responsible party: the individual or sole proprietor, one of the general partners, one of the members or managers of the limited liability company, or an officer of the corporation. The title of the responsible party must be specified, e.g., sole proprietor, general partner, member, president.

5. **Verification.**

A verification page is provided in the application. The name of the person who completes and signs the application must be typed or printed by the notary in the space provided in the verification. The notary's name must be typed or printed below the notary's seal. The verification must be affixed to the original and each of the 9 copies.

2. The following is a list of exhibits which may be required for a successful application. See the body of the form for further instruction on which exhibits are required for your particular case.

LIST OF EXHIBITS

EXHIBIT A: **If a limited liability company,** attach a copy of the articles of organization and the operating agreement; **if a partnership or limited partnership,** attach a copy of the partnership agreement; **if a corporation,** attach copy of the articles of incorporation and all amendments, if any.

EXHIBIT B: **If a limited liability company,** attach a list of members; **if a partnership or limited partnership,** attach a list of partners and officers and the percentage of equity interest of each; **if a corporation,** attach a list of all directors and principal stockholders with the number of shares held by each, and the names, titles, and addresses of the principal corporate officers.

EXHIBIT C: **If a limited liability company or corporation and not organized in North Carolina,** attach a copy of the **certificate of authority to do business** in North Carolina, issued by the Secretary of State.

EXHIBIT D: If Applicant has directors, partners, officers, or members affiliated with any other telecommunications company, attach a list of the companies and a description of the affiliation.

EXHIBIT E: **If Applicant has a parent, affiliate(s) or subsidiary(ies),** provide an **organizational chart** which identifies each entity and its relationship to the Applicant.

EXHIBIT F: Applicant's most recent **annual report to stockholders,** most recent **SEC 10k, or audited financial statements** for the most recent twelve months; or a current **Balance Sheet** and an **Income Statement** reflecting current and prior year balances for the twelve months ended as of the date of the Balance Sheet or, if more readily available, for the period since the close of the preceding calendar year;

EXHIBIT F1: The parent company's or equity partner's most recent **annual report to stockholders,** most recent **SEC 10k** or **audited financial statements** for the most recent twelve months;

EXHIBIT F2: A current **Balance Sheet** for a parent company or equity partner;

EXHIBIT F3: An **Income Statement** for a parent company or equity partner reflecting current and prior year balances for the twelve months ended as of the date of the **Balance Sheet** or, if more readily available, for the period since the close of the preceding calendar year;

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EXHIBIT F4: A letter of commitment from a parent company or equity partner for financial resources if Applicant is relying on such a commitment.

EXHIBIT G1: Annual projected income statement and statement of projected cash flows for each year until net cash is provided by the operating activities of the applicant or three years, whichever period is longer.

EXHIBIT G2: Detailed description of the assumptions for each item reflected in the projected income statement and cash flow statement. The description should provide information on key assumptions, including, but not limited to: number of customers, payroll costs, the number of persons employed (including independent contractors), and sources of external funds (banks, investors).

EXHIBIT G3: Narrative description of the applicant's plan(s) for achieving the projected cash flow amounts set forth in the statement of projected cash flows **(EXHIBIT G1).**

EXHIBIT G4: Commitment letters, letters of intent, etc. from lenders and investors to provide funds through the first 12 months of operations.

EXHIBIT H: If the Applicant is a newly created entity, a description of the experience of each principal officer, manager, or managing partner and any other documentation which would demonstrate managerial and technical ability.

EXHIBIT I: If the Applicant is electing regulation under G.S. 62-133.5(h), an election filing in accordance with the "CERTAIN SUBSECTION (H) REQUIREMENTS AFTER SESSION LAW 2010-173" set forth in Appendix B of the Commission's August 5, 2010 Order in Docket No. P-100, Sub 165.

EXHIBIT J: If the Applicant is electing regulation under G.S. 62-133.5(l), an election filing in accordance with the Commission's May 17, 2011 Order in Docket No. P-100, Sub 165a.

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DOCKET NO. P-100, SUB 167

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Petition of Sprint to Reduce Intrastate	)	
Switched Access Rates of Incumbent	)	ORDER SCHEDULING
Local Exchange Carriers in North	)	HEARING AND ADOPTING
Carolina	)	ISSUES LIST

BY THE CHAIRMAN: On May 31, 2011, the Public Staff, as requested by the Commission, filed a Report setting forth the results of the recent meetings of the Access Charges Working Group (ACWG). The Public Staff reported that the ACWG has recommended that the Commission should institute a formal evidentiary proceeding to determine whether access charges should be reduced and, if so, whether any funding mechanism should be established. The Public Staff, on behalf of the ACWG, provided a proposed procedural schedule and issues list for the Commission's consideration.

The Chairman has carefully considered the ACWG report as submitted by the Public Staff and concludes that good cause exists to schedule a hearing and set forth a procedural schedule for such hearing (attached hereto as Attachment A) and, furthermore, to set forth an issues list pertaining to such hearing (attached hereto as Attachment B).

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION
This the 3rd day of June, 2011.

NORTH CAROLINA UTILITIES COMMISSION
Renné Vance, Chief Clerk

dl060311.01

Attachment A
Page 1 of 3

Procedural Schedule and Guidelines

1. A hearing to address the issues identified in Attachment B will commence on October 18, 2011 at 9:30 a.m. in the North Carolina Utilities Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina. Attorneys for the parties shall gather on such date at the Commission Hearing Room at 9:00 a.m. to discuss any outstanding procedural issues.

2. The parties shall prefile direct testimony no later than August 10, 2011 and the parties shall prefile rebuttal testimony by September 27, 2011. To expedite discovery, at the same time direct testimony is filed, parties shall file or otherwise make available to participating parties electronic spreadsheets underlying proposals set forth in the testimony with regard to the establishment of a fund or other formal revenue recovery mechanism.

3. The parties shall file their estimated cross-examination times and preferred order of witnesses by no later than October 14, 2011.

4. Discovery shall be conducted according to the following provisions, subject to modification for good cause shown:

a. Initial discovery shall begin on the date of the Commission's Order and shall be served by July 8, 2011. Discovery on direct testimony shall begin on August 11, 2011, and shall be served by August 26, 2011. Discovery on rebuttal testimony shall begin on September 28, 2011 and shall be served by October 7, 2011. Any discovery requests served after the filing of rebuttal testimony shall be limited to new matters addressed in rebuttal testimony.

b. Parties shall have up to 10 calendar days to file with the Commission objections to discovery requests on an item-by-item basis. However, for discovery requests filed after the filing of rebuttal testimony, the period to file objections on an item-by-item basis is 5 calendar days. The party objecting to discovery shall e-mail a copy of its objections to the party seeking discovery contemporaneously with its filing.

c. If the party seeking discovery intends to pursue requests which are the subject of objection, it must file responses to the objections on an item-by-item basis within 7 calendar days after the time the responding party files its objections. However, the period to file responses to objections filed after the filing of rebuttal testimony is 5 calendar days. The party seeking discovery shall e-mail a copy of its responses to the party objecting to the data requests contemporaneously with its filing. The Commission will resolve the objections raised by the parties based on the arguments presented in the objections and responses, or such further documents or arguments as it may request.

Attachment A
Page 2 of 3

d. Parties receiving discovery requests shall serve answers to requests to which they have not objected on the party seeking the discovery within 21 calendar days of the service of such requests. However, parties receiving discovery requests after the filing of rebuttal testimony shall respond to requests to which they have not objected within 10 calendar days of the service of such requests.

e. If the Commission orders a party to answer discovery requests to which it has objected, the party shall have 10 calendar days from the date of such order requiring disclosure to serve answers to such discovery requests. However, the party shall have 5 calendar days from the date of such order with respect to discovery requests that are served after the filing of rebuttal testimony.

f. No party shall direct more than an overall total of 75 data requests (in one or more sets) to any other party, except upon leave of the Commission for good cause shown or by agreement with the other party. Parts and subparts shall be counted as separate data requests. Other parties believe this language is unnecessary.

g. Any motion for subpoena of a witness to appear at the evidentiary hearing shall be filed with the Commission at least ten days before the hearing, shall be served by hand delivery or facsimile to the person sought to be subpoenaed at or before the time of filing with the Commission, and shall make a reasonable showing that the evidence of such person will be material and relevant to an issue in the proceeding. G.S. 62-62. Unless an objection is filed, the Chief Clerk shall issue the requested subpoena within one business day of the filing of such motion.

h. Depositions are allowed on at least seven days written notice prior to the taking of the deposition; provided however, all depositions must be taken by October 4.

5. The parties shall negotiate and enter into any necessary protective agreements as soon as practicable.

6. All incumbent LECs and participating TMCs shall provide to the Public Staff within ten days of this Order refreshed data as of year end 2010 regarding access lines, access rates, and minutes of use. Such data will be compiled by the Public Staff and distributed to the parties pursuant to the Commission's Order Granting Motion for Amended Protective Order dated April 29, 2011 and the Addendum to Protective Order approved by the Commission in that order.

Attachment A
Page 3 of 3

The above guidelines are without prejudice to the parties conducting informal discovery or exchanging information by agreement at any time with the understanding that such will not be enforceable by the Commission if outside the guidelines.

Attachment B
Page 1 of 2

P-100, Sub 167 – Issues List

1. What are the existing intrastate switched access charges imposed by local service providers?

2. Should intrastate switched access charges of local carriers be reduced? If so, (a) to what level should access charges be reduced, (b) which entities (i.e., ILECs, TMCs, CLPs, etc.) should be required to reduce access charges; and (c) when should the mandated reductions occur?

3. Identify any legal impediments to mandated intrastate switched access charge reductions for any local service provider.

4. Should other forms of intrastate interexchange intercarrier compensation (ICC) be reduced simultaneously to the same rates of any reduced intrastate switched access charges, such as ICC for calls within the expanded local area and also calls within the intraLATA toll area as covered by the IntraLATA Toll Originating Responsibility Plan (ITORP) tariff?

5. What tangible benefits would flow to North Carolina consumers as a result of access charge reform?

6. Is there a demonstrable link between the rates currently established for intrastate switched access and support for universal service?

7. What effect, if any, would access reform have on COLR obligations, universal service, and affordable local rates?

8. What are the economic effects of mandating intrastate switched access charge reductions on local service providers?

9. Assuming the adoption of mandated intrastate access charge reductions, should the Commission assure that companies may recover lost revenues? For instance, should local exchange rates be rebalanced with or without the support of a state Universal Service Fund that the Commission may establish pursuant to G.S. 62-110(f1), and/or should alternative sources of revenue that access line providers currently have (e.g., features, DSL, video) cover some or all of the lost revenue?

10. Assuming the adoption of mandated intrastate access charge reductions, is it necessary and in the public interest for the Commission to mitigate the effects of the lost revenues by adoption of a formal funding mechanism? If the establishment of a fund is proposed, indicate how such a fund would work, including consideration of the following: (a) the entities that should be permitted to draw from the fund; (b) on what basis entities would be permitted to draw from the fund, (c) whether rebalancing of local rates should be required to draw from the fund and, if so, what the rebalancing criteria should be; (d) the entities that should be required to contribute to the fund; (e) what should be the basis for contributions; (f) should the fund be resized each year to account for minutes of

use and access line losses; and (g) whether the fund should have a predetermined sunset provision or review process.

11. Identify any legal impediments to the Commission's establishment of a fund to defray access charge reductions.

12. Would implementation of a Universal Service Fund or other fund, if any, replace all other support programs such as the Revenue Stability/High Cost Fund? How would the existing funds be addressed in either instance?

13. What existing or proposed FCC policies and orders bear on the issue of intrastate switched access charge reform?

DOCKET NO. P-100, SUB 167

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Petition of Sprint to Reduce Intrastate Switched Access Rate of Incumbent Local Exchange Carriers in North Carolina	)))	ORDER SEEKING COMMENTS ON THE IMPACT OF THE FCC'S CONNECT AMERICA FUND ORDER

BY THE CHAIRMAN: On November 18, 2011, the Commission issued its Order Concerning Declassification Issues and Proposed Schedule for Briefs and Proposed Orders that required the Access Charges Working Group (ACWG) to file a proposed schedule for the filing of proposed orders and briefs within two weeks of the issuance of the Federal Communications Commission's (FCC) Connect America Fund Order. Later that same day, the FCC issued the 759-page Connect America Fund Order[1].

On December 2, 2011, the Public Staff, on behalf of the ACWG, filed a letter stating that the ACWG agrees that comments on the impact of the FCC's Order should be filed within 60 days of the December 2, 2011 filing (January 31, 2012) and reply comments 30 days thereafter (March 1, 2012). However, the Public Staff noted that members of the ACWG have developed two proposals for the Commission's consideration regarding the filing of briefs and/or proposed orders. CompSouth, Sprint, Time-Warner, and Verizon proposed that after the submission of comments, the parties would await further Commission order on how to proceed thereafter. The ILEC Coalition proposed that the parties file briefs and/or proposed orders within 30 days of the filing of reply comments, unless the Commission orders otherwise.

WHEREUPON, the Chairman reaches the following

CONCLUSIONS

The Chairman concurs with the ACWG that comments on the impact of the FCC's Connect America Fund Order should be filed on January 31, 2012, and reply comments by March 1, 2012. The Chairman furthermore concurs with CompSouth, Sprint, Time-Warner, and Verizon that parties should await further Commission order on how to proceed thereafter.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 7th day of December, 2011.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

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[1] See Connect America Fund, WC Docket No.10-90, Report and Order and Further Notice of Proposed Rulemaking, FCC 11-61 (rev. Nov. 18, 2011).

DOCKET NO. P-100, SUB 167

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Petition of Sprint to Reduce Intrastate Switched	)	
Access Rates of Incumbent Local Exchange Carriers	)	ERRATA ORDER
in North Carolina	)	

BY THE CHAIRMAN: On December 8, 2011, the Public Staff filed a letter in the above captioned docket notifying the Commission that it had previously misidentified Time Warner as one of the proponents of the proposal that the Commission adopted in its Order of December 7, 2011 (Order). In the Order, the Commission twice referenced Time Warner as one of the proponents of the proposal regarding procedures. The correct proponent of the proposal was the North Carolina Cable Telecommunications Association (NCCTA). The Public Staff requested that an errata to the December 7 Order be issued replacing Time Warner with NCCTA.

Whereupon the Chairman find good cause to issue this Errata Order replacing Time Warner with NCCTA in the Order.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION
This the 9th day of December, 2011.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

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DOCKET NO. T-100, SUB 69

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Petition by Movin' on Movers to Amend Rule R2-8.1 Applications for Certificates Of Exemption; Transfers; and Notice	)))	ORDER REGARDING CRIMINAL HISTORY RECORDS CHECKS

BY THE COMMISSION: By Order issued August 29, 2008, the Commission, among other things, implemented a criminal history records check requirement for household goods carriers. Such requirement was made applicable to new applicants for certificates of exemption as well as to carriers who held such certificates as of the date of the Order.[1] Under the August 29, 2008 Order, existing certificate holders were to submit records checks to the Commission "in connection with [each company's] first annual report following the issuance of [the August 29, 2008] Order."

On April 14, 2009, in a Commission notice sent to all certificated carriers, Bruce Ramaekers, Transportation Utilities Analyst, consistent with the Commission's Order of March 31, 2009, clarified the nature of the information to be submitted in satisfaction of the Commission's criminal history records check requirement. Such notice clarified that "[c]riminal history record[s] checks must be fingerprint-based, nationwide, and conducted by the United States Federal Bureau of Investigation (FBI)."

As the required records check is fingerprint based, an issue has arisen in those instances where the quality characteristic of an individual's fingerprints is too low or otherwise inadequate for processing by the FBI. In such instances, individuals so situated are, effectively, unable to submit, as required by the Commission, a fingerprint-based records check that has been conducted by the FBI.

Consequently, in consideration of the foregoing, the Commission is of the opinion that good cause exists to prescribe an alternative means of satisfying the criminal history records check requirement, in lieu of the approach that is currently required, for use in certain strictly limited situations. Therefore, in those instances where an individual's fingerprints have been rejected by the FBI on at least two separate occasions because the quality characteristic of the individual's fingerprints is too low or otherwise inadequate for processing by the FBI and where on at least one of those occasions of rejection the fingerprints submitted to the FBI had been taken at a law enforcement agency, the Commission finds and concludes that the criminal history records check requirement, as provided for in Commission Rule R2 8.1(a)(3)(f), may be satisfied by such an individual's completion and submission of and compliance with *NCUC Form CH-1, Alternative Criminal History Records Check Form and Affidavit (Affidavit)*; a copy of which is

[1] In particular, the Order amended Commission Rule R2-8.1(a) to include the present requirement for new applicants. See Rule R2-8.1(a)(3)f. Ordering Paragraph No. 2 of the August 29, 2008 Order, in effect, expanded the requirements of the amended Rule to include current holders of certificates of exemption.

attached hereto as Appendix A. This form may also be accessed from the Commission's website: http://www.ncuc.net.

Regarding the *Affidavit*, in addition to other information, it requires the submission of a criminal history records check performed by the North Carolina State Bureau of Investigation (SBI). As indicated in the *Affidavit*, an SBI records check is to be obtained through the SBI's *Right to Review Process*, which requires the submission of legible fingerprints. In that regard, instructions to the *Right to Review Process* provide, in pertinent part, as follows:

> If the fingerprints are of insufficient quality to conduct the search . . . the fingerprint card will be returned to the requestor and another set of fingerprints will be required to complete the process.

The Commission, through its staff, has discussed the forgoing provision with the SBI's Applicant Unit Supervisor and is advised that the present provision is not intended to apply in those instances where insufficient fingerprint quality is a function of the low quality characteristic of the requestor's fingerprints; but rather, is intended to apply in those instances where insufficient fingerprint quality arises from the use of marginal or ineffective techniques in the fingerprinting process, i.e., in the actual taking/rolling of the fingerprints. The Commission is further advised that, in those rare instances where a fingerprint-based records check cannot be performed by the SBI because of the low or otherwise inadequate quality characteristic of the requestor's fingerprints, the SBI will then and in that event conduct a statewide, name-based criminal history records check and provide a report as to its findings under that approach rather than under a fingerprint-based approach. Under such circumstances, a name-based approach will be acceptable to the Commission.

WHEREFORE, the Commission reaches the following

CONCLUSIONS

In consideration of the foregoing, the Commission is of the opinion, and so finds and concludes, that the alternative means of satisfying the criminal history records check requirement as discussed above, should be, and hereby is, adopted for use by the Commission. Said alternative means shall be used only in those instances where an individual's fingerprints have been rejected by the FBI on at least two separate occasions because the quality characteristic of the individual's fingerprints is too low or otherwise inadequate for processing by the FBI and where, on at least one of those occasions of rejection, the fingerprints submitted to the FBI had been taken at a law enforcement agency.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 14th day of January, 2011.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

bk011411.01

Appendix A

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
RALEIGH, NORTH CAROLINA

HOUSEHOLD GOODS CARRIER
ALTERNATIVE CRIMINAL HISTORY RECORDS CHECK FORM and AFFIDAVIT

***NOTE:** This Form and Affidavit are to be completed and submitted in compliance with Commission Rule R2-8.1(a)(3)(f), in those instances where the subject individual's fingerprints have been rejected by the U.S. Federal Bureau of Investigation (FBI) on at least two separate occasions because the quality characteristic of the individual's fingerprints is too low or otherwise inadequate for processing by the FBI and where on at least one of those occasions of rejection the fingerprints submitted to the FBI had been taken at a law enforcement agency.*

In Re:

____ T-__________
Carrier's Name and Company Number T-

1. Name of Affiant:____
First, Middle, Last, Suffix (e.g., Sr., Jr., II, etc.) (Print) Title/Position

2. Date of Birth: ____________________, Phone Number: (___)______-__________, and

Email Address: ____

3. Provide and mark as "Appendix 3" all correspondence from the FBI showing that on at least two occasions, the FBI rejected affiant's fingerprints because the quality characteristic of affiant's fingerprints, as submitted, was too low or otherwise inadequate for processing.

All Correspondence attached ___YES or ___NO (Check one.)

4. Provide receipt or other documentation (and mark as "Appendix 4") showing that, on at least one of the occasions where the FBI rejected affiant's fingerprints, a law enforcement agency such as a local police department, sheriff's office, or city/county bureau of identification took the fingerprints that affiant submitted to the FBI in an attempt to comply with Commission Rule R2-8.1

Receipt or other documentation attached ___YES or ___NO (Check one.)

NCUC Form CH-1
(January 2011)

Appendix A

Alternative Criminal History Records Check Form and Affidavit – Continued
Page 2

5. Provide the names of all of the states in the United States where affiant has lived in the preceding 10 years other than North Carolina, if any.

____

____

6(a). In the past 10 years, has affiant been convicted of any criminal offense including major traffic offenses?

___YES or ___ NO (Check one.)

6(b). Does affiant have any criminal charges that are pending or that have not been finally dismissed and/or that may be reinstated?

___YES or ___ NO (Check one.)

6(c). If affiant answered "YES", to 6(a) and/or 6(b) above, please describe, in detail below, each and every criminal offense, pending charge, or charge that may be reinstated. In addition, include the name of the arresting/charging agency; approximate date of arrest/charge; sentencing court; date of sentence; sentence or penalty imposed; indicate whether affiant pleaded guilty or not guilty; and indicate if affiant is currently under any supervision by a court or department of corrections for each offense. If additional space is needed, please indicate below that affiant has enclosed such information and mark this enclosure as "Appendix 6(c)."

____

____

____

____

____

NCUC Form CH-1
(January 2011)

Appendix A

Alternative Criminal History Records Check Form and Affidavit – Continued
Page 3

7. If affiant has used different names, aliases, or social security numbers within the preceding 10 years, provide the different names, aliases, and social security numbers that affiant utilized within that period.

____

____

____

____

____

8. Please contact the North Carolina State Bureau of Investigation (SBI) and obtain a copy of affiant's North Carolina criminal history record using the SBI's Right to Review Process. Attach the results of the search (i.e., all original SBI response documents), including the "formal response letter on SBI letterhead indicating the findings of the Right to Review Process" and affiant's criminal history record, if any, supplied by the SBI and mark as "Appendix 8". (A copy of the Right to Review Request Form can be found at: http://www.ncdoj.gov/getdoc/97522fed-73d5-4549-9f2c-d804e90bc57a/Right-to-review-packet.aspx.) The SBI requires the submission of fingerprints in connection with this process. **To satisfy the Commission's requirement in this regard, affiant's fingerprints must be taken by a local law enforcement agency in order to ensure that good quality fingerprints are submitted to the SBI. Attach receipt or other documentation showing that the fingerprints submitted to the SBI were taken in that manner and mark as "Appendix 8-1."** As of January 2011, the date of adoption of this requirement, the SBI's fee for processing each criminal history records check is $14. For more information on the Right to Review Request Form, the SBI can be reached at (919) 662-4509, extension 6266.

____

Appendix A

Alternative Criminal History Records Check Form and Affidavit — Continued
Page 4

VERIFICATION UNDER OATH REGARDING ACCURACY OF THE INFORMATION IN ITEM NOS. 1 THROUGH 8 OF THE AFFIDAVIT

(NOTE: THIS VERIFICATION SHALL BE COMPLETED BY THE INDIVIDUAL NAMED IN ITEM NO. 1, PAGE 1.)

Under the penalty of perjury,

I, ____ (print name), the affiant, am an applicant, sole proprietor, principal, partner, or member with respect to the above-referenced company and I state and attest that the information on this form and the attached information is filed on my behalf as required by the North Carolina Utilities Commission; that all of the information provided on this form and attached is true, correct, and complete; and that copies of any documents presented to the Commission as part of this information are genuine. This certification is made under oath and under penalty of perjury. To the best of my knowledge, information, and belief, all of the information contained herein and attached is accurate and true, no material information or fact has been knowingly omitted or misstated. (Note: Providing false information to the Commission is punishable by fine and/or imprisonment pursuant to N.C.G.S. 62-310 and N.C.G.S. 62-326.)

______________________________ Signature of Person Making Verification (Affiant)

______________________________ Title

______________________________ Date

Subscribed and sworn before me this the ____________ day of ________________, ____

______________________________ Notary Public Signature

______________________________ Printed Name of Notary

My Commission Expires: ________________

This Form and Affidavit, including attachments, (original and two copies) should be returned to the North Carolina Utilities Commission, Chief Clerk's Office, 4325 Mail Service Center, Raleigh, NC 27699-4325. Each page of the original and all copies should be clearly marked **CONFIDENTIAL.**

NCUC Form CH-1
(January 2011)

DOCKET NO. E-7, SUB 949

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Citizens to Protect Kituwah Valley and Swain County, c/o Natalie Smith, 938 Tsalagi Road, Cherokee, North Carolina 28719, Complainant v. Duke Energy Carolinas, LLC, Respondent	)	ORDER RULING ON COMPLAINT

HEARD: Tuesday, August 2, 2011, at 9:30 a.m. in District Courtroom, Swain County Courthouse, 101 Mitchell Street, Bryson City, North Carolina

BEFORE: Chairman Edward S. Finley, Jr., Presiding, and Commissioners Lorinzo L. Joyner and Susan W. Rabon

APPEARANCES:

For Duke Energy Carolinas, LLC:

Robert W. Kaylor, Law Office of Robert W. Kaylor, P.A., 3700 Glenwood Avenue, Suite 330, Raleigh, North Carolina 27612

Brian L. Franklin, Associate General Counsel, Duke Energy Corporation, 550 South Tryon Street, DEC45A/Post Office Box 1321, Charlotte, North Carolina 28201

For Citizens to Protect Kituwah Valley and Swain County:

John D. Runkle, Attorney at Law, Post Office Box 3793, Chapel Hill, North Carolina 27515-3793

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

BY THE COMMISSION: On March 31, 2010, Citizens to Protect Kituwah Valley and Swain County (Complainant) filed a complaint against Duke Energy Carolinas, LLC (Duke). In summary, Complainant alleged that its members were residents of Swain County and that some of them were members of the Cherokee Indian Tribe; that Duke was in the process of building a 161-kilovolt (kV) transmission line and a substation or tie station; that the tie station was located in Kituwah Valley near Bryson City in Swain County; that the proposed tie station would desecrate the Kituwah Valley, a sacred site of fundamental importance to the spiritual and cultural life of the Cherokee Indian Tribe; that the transmission line under construction was generally located along a right-of-way easement granted much earlier to Duke's predecessor in title, Nantahala Power & Light Company (Nantahala), and used by Nantahala for a wooden pole line; that the line being constructed by Duke was a steel lattice tower line and would have a highly destructive effect on the aesthetic and monetary value of the property of Complainant's members; that in some instances the new transmission line was being constructed on property of Complainant's members outside the boundaries of Duke's right-of-way; and that Duke had illegally begun construction of the transmission line without obtaining a certificate of environmental compatibility and public convenience and necessity (CPCN) from the Commission as required by the Transmission Line Siting Act (the Act), G.S. 62-100 to 62-107. Complainant requested that Duke be ordered to stop work on the tie station and prohibited from continuing work on the transmission line until Duke obtained a CPCN.

On April 1, 2010, the Commission issued an order scheduling an oral argument on April 27, 2010, to consider Complainant's motion to stop work. On April 16, 2010, Duke filed a motion to hold the complaint in abeyance, asserting that it was considering relocation of the tie station and had suspended work on the tie station. Further, Duke denied that it was required to obtain a CPCN under the Act and requested that the oral argument scheduled for April 27, 2010, be waived. Complainant filed a response on April 23, 2010, objecting to Duke's request for a waiver of the oral argument. On the same date, Duke filed a response adhering to its previously stated position.

On April 23, 2010, the Commission issued an order canceling the oral argument and denying Complainant's motion to issue a stop work order, citing Duke's commitment to halt construction at the Hyatt Tie Station and refrain from extending the transmission line beyond the portion completed on April 19, 2010. In addition, the Commission denied Duke's motion to hold the complaint in abeyance.

On May 10, 2010, Duke filed an answer and motion to dismiss the complaint for failure to state a claim for relief. Duke alleged that the transmission line in question was the Wests Mill Transmission Line, which had been in place for over 50 years, and that Duke was seeking to upgrade it from 66-kV to 161-kV to accommodate growing demand in the area. Duke asserted that discussions were in progress to find a new location for the proposed tie station, and it reiterated its contention that no CPCN for the upgrade of the transmission line was necessary.

On October 19, 2010, Duke filed a motion for summary judgment in which it noted, among other things, that the parties had agreed to a relocation of the planned tie station at a location some distance from the Kituwah Valley site. On November 5, 2010, Complainant filed a response to the motion, supported by extensive affidavits, photographs and other materials. Duke filed a reply on December 1, 2010.

On December 3, 2010, the Commission issued an order scheduling an oral argument on the motion for summary judgment for December 20, 2010, requesting the Public Staff to participate in the oral argument, and directing the Public Staff to file a statement of its position by December 16, 2010. The Public Staff filed its statement of position on December 16, 2010, and the oral argument was held as scheduled on December 20, 2010.

On January 14, 2011, in response to a Commission inquiry during the oral argument, Complainant filed a response acknowledging that it was unable to offer evidence showing that any of the towers for the upgraded transmission line were located outside of Duke's previously existing right-of-way.

On April 13, 2011, the Commission issued an Order Granting Summary Judgment, in Part, Denying Summary Judgment, in Part, Scheduling Hearing, and Establishing Deadlines for Filing Testimony (Summary Judgment Order). The Commission granted partial summary judgment for Duke, concluding that (1) pursuant to the Act, Duke was not required to obtain a CPCN before upgrading the 66-kV Wests Mill Transmission Line to 161-kV, and (2) the fact that the upgraded transmission line included two or more electric conductors rather than only a single conductor did not violate the terms of Duke's easement. Further, the Commission held that Duke was not required to obtain a CPCN for construction of the planned tie station. However, the Commission declined to grant summary judgment against Complainant on the claims relating to the construction of the Hyatt Tie Station at the originally planned Kituwah Valley location, noting that these claims could not be fully resolved until construction at the alternate location was completed. In addition, the Commission noted that it was not authorized to award monetary damages for diminution in the value of the property of Complainant's members resulting from the upgrade of the transmission line. Finally, the Commission held that Complainant had raised an issue of material fact and was entitled to an evidentiary hearing on the question of whether Duke had "acted in a reasonable manner in its siting and construction of the transmission line upgrade." Therefore, the Commission ordered Complainant to file direct testimony and exhibits on that issue by May 27, 2011, and scheduled an evidentiary hearing to be held on August 2, 2011, in Bryson City, North Carolina.

On May 27, 2011, Complainant filed the testimony of Thomas Belt, Sharon Chilson, Larry M. Dehart, Lance Gillespie, Dennis Hutchinson, Peggy Jennings, Dorothy Proctor, Billy Roland, Jennifer Simon, Natalie Smith, Kathleen D. Travitz and Paul Wolf, together with the exhibits of witness Belt. On July 15, 2011, Duke filed the testimony of Paul Morgan, Michael D. Robinson and Jim Hollifield, together with the exhibits of witnesses Robinson and Hollifield.

On July 19, 2011, Duke filed a motion to strike the entire testimony of witnesses Chilson, Dehart, Hutchinson, Jennings, Smith and Travitz, as well as designated portions of the testimony of Complainant's other witnesses. On August 1, 2011, the Commission issued an order granting the motion to strike the entire testimony of witnesses Chilson, Dehart, Hutchinson and Jennings and striking portions of the testimony of Complainant's other witnesses.

On August 2, 2011, the matter came on for hearing as scheduled. In response to an oral motion by Complainant, the Commission restored to the record a portion of witness Roland's testimony that had been stricken. Complainant presented the testimony of witnesses Belt, Gillespie, Proctor, Roland, Simon, Smith, Travitz and Wolf. Duke presented the testimony of witness Morgan and the testimony and exhibits of witnesses Robinson and Hollifield. Duke's three witnesses testified as a panel.

Based upon the foregoing, the testimony and exhibits introduced at the hearing, and the entire record in this proceeding, the Commission makes the following

ELECTRIC – COMPLAINT

FINDINGS OF FACT

1. Pursuant to the Commission's complaint authority under G.S. 62-73, Complainant's complaint is properly before the Commission as one by an unincorporated association whose membership includes customers in Swain County receiving electric service from Duke and members who own property encumbered by and affected by Duke's transmission and transformation activities.

2. Duke is properly before the Commission as a duly certified public utility in North Carolina, authorized to provide retail electric service to all persons in its service area.

3. During the 1960's, Nantahala acquired easements and constructed the Wests Mill Transmission Line located in Macon and Swain Counties. The original transmission line extended from the Wests Mill Substation in Macon County to the East Bryson Tap and continued to the Bryson Hydroelectric Plant. It was built as a single circuit 66-kV line, with the conductors supported by 60-foot wooden poles. Subsequent to construction of the original transmission line, Nantahala was acquired by Duke.

4. In 2008, Duke determined that increased customer demand and the provision of reliable service in Swain and Jackson Counties made it necessary to upgrade the Wests Mill Transmission Line to 161-kV and build a new tie station at Hyatt Creek (Hyatt Tie Station). The primary reason for the upgrade was the major expansion of Harrah's Cherokee Casino and Hotel and the expected growth in the vicinity of the Hotel in Swain County.

5. The upgrade of the transmission line was accomplished by replacing the existing single circuit 66-kV line with a double circuit line having a capacity of 161-kV. In addition, the existing 60-foot wooden poles supporting the existing 66-kV line were replaced with steel lattice towers which are about 45 feet wide and 140 feet tall, or in some instances custom designed single steel poles of similar height. The increased height achieved by the steel towers and poles improved the safety and reliability of the transmission line because the increased height raised the transmission line above the tree line.

6. The increased height of the transmission line required more strength than wooden poles could provide. The upgrade to the facilities allowed Duke to decrease the number of vertical structures along the transmission line. In deciding whether to replace the wooden poles with single steel poles or steel lattice towers, the criterion that Duke used was whether the terrain of the site was suitable for a tower base.

7. Duke originally planned for the upgraded 161-kV line to extend from the Wests Mill Substation to the proposed Hyatt Tie Station in Kituwah Valley, where the voltage would be reduced to 66-kV. However, a controversy arose regarding the impact that the Hyatt Tie Station would have on the cultural and spiritual aspects of the Kituwah Valley.

8. On February 4, 2010, the Tribal Council of the Eastern Band of Cherokee Indians adopted a Resolution stating that there had been numerous complaints and growing concern about the construction of the Hyatt Tie Station "in close proximity to and within the viewshed of our ancient Mothertown, Kituwah." The Resolution also stated that the Eastern Band of

Cherokee Indians "did not have the opportunity to have any input and object to this site prior to initiation of construction."

9. On March 9, 2010, the Swain County Board of Commissioners adopted an ordinance establishing a 90-day moratorium on the issuance of building permits and soil and erosion permits. The ordinance purportedly was applicable to "utility substations, tie-in stations, and switching stations and other structures and buildings associated therewith in Swain County that create visual appearances that threaten to destroy the scenic and unspoiled aesthetic features of the County and the quality of life."

10. In response to the concerns of the individual property owners whose interests are at issue here (Property Owner Complainants), the Eastern Band of Cherokee Indians, the Swain County Board of Commissioners and others, Duke began working cooperatively with the Eastern Band of Cherokee Indians, Swain County and others when it became aware of the concerns about the location of the Hyatt Tie Station. Further, prior to the complaint being filed, Duke temporarily halted construction at the Hyatt Tie Station site.

11. In its April 16, 2010, filing with the Commission, Duke stated that it had stopped work on the Hyatt Tie Station while negotiating with interested persons to identify an alternate site, but that it was continuing with the first part of the transmission line upgrade to connect it to the East Bryson Tap in order to prevent significant reliability issues in the area during the summer of 2010. Duke further stated that once there was a resolution to the ultimate location of the tie station, it would extend the transmission line to that location. Until then, Duke would refrain from completing the additional upgrade of the transmission line beyond the East Bryson Tap.

12. On August 3, 2010, in response to the concerns of the Property Owner Complainants, the Eastern Band of Cherokee Indians, the Swain County Board of Commissioners and others, Duke announced that it had decided not to build the Hyatt Tie Station and was evaluating alternate sites. At a later date, Duke elected to build the Swain Tie Station in the Swain County Industrial Park, west of the proposed Hyatt Tie Station.

13. In Duke's original plan, the upgraded 161-kV line would have fed the Hyatt Tie Station. However, the design of the transmission line upgrade was changed to have the 161-kV line feed the Swain Tie Station. The 66-kV circuit of the upgraded transmission line will feed the Wests Mill Substation from the Swain Tie Station.

14. The portion of the 161-kV transmission line upgrade built on steel lattice towers numbered 65 through 74, ending at the East Bryson Tap, is presently used as back-up capacity in the event that the 66-kV line is inoperable.

15. The 66-kV line now supported by steel lattice towers numbered 65 through 74, ending at the East Bryson Tap, will likely reach its capacity within ten years.

16. Paul Wolf, Kathleen D. Travitz, Dorothy Proctor, Jennifer Simon, Billy Roland and Lance Gillespie live in rural areas of Swain County, close to the Wests Mill Transmission Line. Wolf's residence is located approximately 200 feet from one of the steel lattice towers supporting the upgraded transmission line. The residence of Proctor and Simon is approximately

100 feet from one of these structures. Roland's house is 50 feet from steel lattice tower number 68, and the residence of Gillespie is 300 to 350 feet from steel lattice tower number 69 or 70. Travitz's residence is in the center of a 50-acre tract, and a steel lattice tower is located adjacent to her property.

17. For those members of Complainant whose residences are within the proximity of a steel lattice tower that affects the view from their homes and yards, the adverse visual and property enjoyment impacts cause a diminution in the value of their homes below the value that would exist had the steel lattice towers not been built.

18. Complainant has not presented sufficient evidence to prove that Duke acted unreasonably and inappropriately in its upgrade of the transmission facilities at issue.

19. Complainant has not presented sufficient evidence to prove that living within close proximity to the upgraded transmission line will cause adverse health effects.

20. The attractive nuisance doctrine does not require Duke to construct fences around its transmission towers or poles.

21. Complainant has not presented sufficient evidence to prove that an employee or contractor of Duke was responsible for the indecent activity which occurred near Wolf's residence.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT 1-2

These findings of fact are informational, procedural and jurisdictional in nature and are uncontested.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT 3-18

The evidence supporting these findings of fact appears from a review of the Commission's official file in this docket, including the testimony and exhibits of Duke's panel of witnesses Robinson, Morgan, and Hollifield; Duke's and Complainant's filings with the Commission; Attachment E to the Complaint; Duke's Motion to Hold Complaint in Abeyance; Duke's Answer to the Complaint, including Exhibit 2; Duke's Motion for Summary Judgment; Duke Energy Travitz Cross-Examination Exhibit No. 2; Duke Energy Roland Cross-Examination Exhibit Nos. 1 and 2; Duke Energy Gillespie Cross-Examination Exhibit No. 1; and the testimony of Complainant witnesses Wolf, Travitz, Proctor, Simon, Roland and Gillespie.

Duke witness Morgan testified that the original transmission line was built in the late 1960s by Nantahala, a subsidiary of Alcoa. Duke subsequently acquired Nantahala from Alcoa. Prior to its upgrade, the line ran from the Wests Mill Substation to the Bryson Hydroelectric Plant and consisted of a single-circuit 66-kV line. For the upgrade, Duke constructed a double-circuit line, with a 161-kV circuit on one side and a 66-kV circuit on the other. The wooden poles previously in use were replaced with steel lattice towers, or in some instances custom designed steel poles. The 161-kV side of the upgraded transmission line will feed the new Swain Tie Station selected by Duke to replace the Hyatt Tie Station in response to objections by Complainant's members and others, and the 66-kV side will feed the Wests Mill Substation from the Swain Tie Station. Both transmission circuits will be used for providing service to customers in the Swain County area.

The need for the upgrade arose from the growth in electric demand in Jackson and Swain Counties, primarily due to a major expansion at Harrah's Cherokee Casino and Hotel, together with the increased development expected in the vicinity of the Hotel following its expansion. The existing Wests Mill Transmission Line was designed for a maximum capacity of 66-kV. Duke needed a line with 161-kV capacity in order to deliver sufficient power to the Swain Tie Station to serve the load centers in Swain County and northern Jackson County. Duke originally planned to terminate the 161-kV portion of the transmission line at the proposed Hyatt Tie Station, on property Duke had purchased for that purpose. Duke witness Morgan testified that for the upgrade of the transmission line Duke constructed a double-circuit line, with a 161-kV circuit on one side and a 66-kV circuit on the other. Duke had undertaken site clearing and preparation activities at the Hyatt Creek site when controversy over the use of the site arose. Also, Duke had begun upgrades to the transmission line to be interconnected at the Hyatt Tie Station at that time. When controversy arose about placing a tie station in the Kituwah Valley, Duke abandoned its plans for the Hyatt Tie Station and chose instead to build the Swain Tie Station in the Swain County Industrial Park and terminate the 161-kV portion of the transmission line there. Thus, the 161-kV side of the upgraded transmission line will feed the new Swain Tie Station, while the 66-kV side will feed the Wests Mill Substation from the Swain Tie Station and will be used for providing service to customers in the Swain County area.

Duke witness Robinson testified on cross-examination that the revised design of the Wests Mill Transmission Line upgrade includes having the transmission line leaving "in the vicinity" of tower number 63 or 64 and going to the Swain Tie Station. Duke Energy Travitz Cross-Examination Exhibit No. 2 consists of 13 pages that diagram the Wests Mill Transmission Line upgrade project. Pages 12 and 13 depict the replacement of original wooden transmission poles numbered 73 through 83 with steel lattice towers numbered 65 through 74. Page 12 shows the transmission line leaving tower number 64 and going west to the Jenkins Branch Substation. Duke witness Morgan testified that the Wests Mill Transmission Line upgrade stopped at the East Bryson Tap. Thus, the Company did not replace any wooden poles with steel structures past the East Bryson Tap. Morgan testified that: "The upgraded line will extend from Wests Mill Tie Station (which serves the area around Bryson City), through and past the Swain Tie Station, all the way to the East Bryson Tap." He further stated, "[T]his design will provide more capacity and long-term reliability for the region because in the future, the 66 kV side, up to the new tie station, can also be operated at 161 kV." Following the construction of the Swain Tie Station, there were ten steel lattice towers (65-74) remaining east of the tie station, supporting a portion of the transmission line that will consist of two 66-kV circuits. These ten towers would have been required to support the 161-kV line interconnected to the Hyatt Tie Station had Duke not abandoned that station in response to the requests of Complainant's members and others.

Duke witness Robinson testified that the taller steel lattice towers were used to replace the existing wooden poles as a grid reliability and safety measure. He stated that raising the transmission line above the tree line greatly increases the likelihood that falling trees will not hit the transmission line. Although Duke witness Morgan testified that the reliability standards of the North American Electric Reliability Corporation (NERC) do not apply to this transmission line because it is a radial extension rather than a network line, Duke's actions enhance the reliability of the Wests Mill Line in compliance with the goals of the NERC standards.

Complainant witness Dorothy Proctor testified that the steel lattice towers are about 45 feet wide and 140 feet tall. They replaced wooden poles that had a much less intrusive and invasive impact on the scenery and landscape. The wooden poles did not "loom above the tree line."

Witness Robinson testified that Duke was able to increase the length of the span between transmission structures and reduce the number of structures by using transmission structures that were taller than the existing wooden poles. As a result, Duke was able to reduce the total number of structures by about 12% compared to the existing line. Further, due to the large number of angles along the line, steel lattice towers had to be used in place of the wooden structures. However, because of the mountainous terrain, the longer spans required the structures to be located on peaks, thereby making the structures more visible. To reduce the visual impact, Duke used darkened galvanized steel for the transmission towers and de-glared aluminum conductor for the transmission line.

Witness Morgan testified that one of Duke's main considerations was to build the transmission upgrade within Duke's existing right-of-way. In siting the upgraded transmission towers, Duke considered the proximity of the towers to residences. However, the length of the line spans, the terrain and the right-of-way limits created some angles that required towers to be built in close proximity to residences. Except to the extent vertical support structures were eliminated with the upgrade, the replacement steel towers or poles were placed in the same locations in the existing pole line within the existing right-of-way as the wooden structures they replaced. Placement of vertical support structures in the mountainous terrain poses difficulties and limits suitable site locations. Because of time considerations in completing the upgrade project and the difficulty of obtaining additional right-of-way, Duke did not consider acquiring additional right-of-way as an alternative to placing transmission towers in close proximity to residences.

Witness Morgan further testified that when he was assigned to carry out the planning study for the transmission line, he was instructed that the line should be designed as a 161/66-kV double circuit line, that Duke's standard steel lattice towers should be used and that the line should utilize Duke's existing right-of-way. The primary reason these parameters were imposed was the time that would be required to redesign the line in the event of a departure from the existing right-of-way, the time required to negotiate with property owners and acquire additional easements in such locations, and the impact this would have on the overall project timeline. Robinson further testified that Duke utilized custom designed steel poles on concrete foundations in areas where it could not physically install a tower grillage base. The use of steel lattice towers was the directive given within the project plan. However, Duke used custom engineered steel poles on a concrete foundation in those places – usually a road, stream or a peak – where it could not physically install a base sufficient to support a steel lattice tower. Duke used steel poles at some angle locations.

Complainant witness Wolf's residence is located approximately 200 feet from one of the steel lattice towers supporting the upgraded transmission line. Wolf testified that the steel lattice towers and 161-kV line have a "huge impact ... on the natural surroundings," and that they are "an intrusion and something that the eye cannot get used to." He stated that "[t]he towers are not subtle as the former wooden poles were" and that "the wooden poles ... blended with the view as they were not above tree lines nor were they as striking against the back drop of the natural environment." He testified that he purchased his property because he wanted to have a mountain home, and he would not have wanted to buy it if the towers had been in place at the time he acquired the property.

Complainant witness Travitz testified that her father transferred approximately 60 acres of land to her in 1998. After years of planning, Travitz and her husband built their dream home on the property. The previously existing wooden frames supporting the 66-kV transmission line did not severely impact the view from their home. She and her husband intentionally built their home with windows looking out over the valley. However, a steel lattice tower is now located adjacent to her property and obstructs the view from her home and other sections of her property. Travitz testified that when the wooden structures at or below the tree line were replaced with four towers they built a new deck at the front of the house to avoid looking at the towers.

Complainant witnesses Proctor and Simon are co-owners of a home that is approximately 100 feet from one of the steel lattice towers. Proctor and Simon testified that they invested their life savings in the property at a time when the smaller wooden transmission structures were the only negative impact on the property views. They stated that the wooden poles were much less intrusive and visually invasive than the steel towers Duke used to replace them because they did not loom above the tree line. After the upgrade project, there are 12 towers within the viewscape of their property. Proctor testified that they can see 6 towers from their front deck. The steel towers are 45 feet wide and 140 feet tall. They do not blend in with the surroundings. The new taller structures have destroyed the aesthetics and enjoyment of their property.

Complainant witness Roland testified that his property is located at 112 Tarheel Way, Bryson City, North Carolina. Roland's house is 50 feet from steel lattice tower number 68. He testified that there were many fewer homes in the area when the initial 66-kV line was built on the right-of-way and that the original wooden poles had a much less significant impact on the surrounding homes and property. When he purchased his property in 2006 he did not anticipate that the right-of-way would be used for such a dramatic change. If he had thought that such a change was possible, he would not have purchased the property and built a home on it. Roland testified that it is inappropriate for Duke to site a large steel lattice tower so close to a home. Further, it is his understanding that the transmission line upgrade between the Swain Tie Station and East Bryson Tap became unnecessary when Duke decided to construct the Swain Tie Station rather than the Hyatt Tie Station. Roland testified that his property is located in the segment of the transmission line upgrade from the Swain Tie Station to the East Bryson Tap. Duke Energy Roland Cross-Examination Exhibit No. 1 is an aerial photograph, identified as a Swain County parcel map, showing the property of Larry William and Lisa L. Roland, 112 Tarheel Way, Bryson City, North Carolina. On the map, with an arrow pointing to the Roland's property is the notation: "Wood pole structure in picture replaced by steel structure #68 at angle within right of way on another owner's property."

Complainant witness Gillespie testified that his property is located at 615 Beck Cove Road, Bryson City, North Carolina. His property is 300 to 350 feet from a steel lattice tower. He also testified that there were many fewer homes in the area when the initial 66-kV line was built on the right-of-way and that the original wooden poles had a much less significant impact on the surrounding homes and property. The lines and wooden poles were mostly below the tree line and blended in with the natural flora and fauna. They were not visible from his property. However, the new steel towers are considerably higher than the tree line and are visible from his property. He purchased 19 acres in the area in 1977. He stated that he did not anticipate that the right-of-way would be used for such a dramatic change. He testified that the main value of this mountain area is its aesthetic value and especially the long-range views. However, the new steel towers erected by Duke violate those long-range views. Gillespie testified that Duke has taken the position that it owns a 100-foot right-of-way and can build whatever it wants to build as long as it stays within its right-of-way. He disagrees with that position and made the analogy of a neighbor building a skyscraper that blocks the view of his adjoining neighbor.

Witness Gillespie testified that it is his understanding that the transmission line upgrade between the Swain Tie Station and East Bryson Tap became unnecessary when Duke decided to construct the Swain Tie Station rather than the Hyatt Tie Station. Gillespie further testified that his property is located in the segment of the transmission line upgrade from the Swain Tie Station to the East Bryson Tap. Duke Energy Gillespie Cross-Examination Exhibit No. 1 is an aerial photograph, identified as a Swain County parcel map, showing the property of Lance and Janet Gillespie, 615 Beck Cove Road, Bryson City, North Carolina. Beck Cove Road is shown traversing the Gillespies' property. In addition, Duke Energy Travitz Cross-Examination Exhibit No. 2 consists of 13 pages that diagram the Wests Mill Transmission Line upgrade project. Page 13 depicts replacement transmission towers numbered 69 through 74. Beck Cove Road is shown as crossing the right of way between replacement towers numbered 69 and 70.

Complainant witnesses Wolf, Travitz, Proctor, Simon, Roland and Gillespie testified that the negative visual and property enjoyment impacts of the transmission towers have caused a diminution in the value of their properties. While the Commission accepts these statements as true, the issue remains as to whether this diminution is compensable, and, as stated elsewhere herein, the Commission concludes that this is not the proper forum in which such issues can be litigated.

On March 31, 2010, Complainant filed its verified Complaint and Motion to Issue Stop Work Order. Paragraph 11 of the complaint stated that on February 4, 2010, the Tribal Council of the Eastern Band of Cherokee Indians adopted a Resolution stating its concern about the construction of the Hyatt Tie Station. A copy of the Resolution was attached to the complaint as Attachment B.

On April 16, 2010, Duke filed a Motion to Hold Complaint in Abeyance in which Duke summarized the history of the Wests Mill Transmission Line upgrade project. Included in that summary were statements that Duke began working cooperatively with the Eastern Band of Cherokee Indians, Swain County and others when it became aware of the concerns about the location of the Hyatt Tie Station. Further, Duke stated that prior to the complaint being filed Duke had temporarily halted construction at the Hyatt Tie Station site. However, Duke stated that it would continue construction necessary to complete the transmission line to the East Bryson Tap, "a step that is necessary for the Company to prevent significant reliability issues in Swain County and part of Jackson County during the summer of 2010."

On May 10, 2010, Duke filed its Answer and Motion to Dismiss Complaint. Under its First Defense, Duke stated that "the Company has been working with the Eastern Band of Cherokee Indians and Swain County for months now in an attempt to forge a mutually beneficial resolution of the issues surrounding the Company's need to continue providing reliable electric service for its customers." In response to paragraph 11 of the complaint, Duke acknowledged that the February 4, 2010 Resolution adopted by the Tribal Council of the Eastern Band of Cherokee Indians "speaks for itself." Under its Third Defense, Duke stated,

> As evidence of the cooperative working relationship with the Eastern Band of Cherokee Indians, the Company has committed to utilize various visual mitigation techniques such as tree leave areas, supplemental new plantings of trees and shrubbery, and the use of darkened steel for both the line and the station. ... The Company provided computer images of the original design and the one with the realignment to various interested parties, including the Eastern Band of Cherokee Indians, and Swain County ....

The computer images, dated February 15, 2010, were attached to Duke's Answer as Exhibit 2.

Attachment E to the Complaint is a copy of the Ordinance adopted by the Swain County Board of Commissioners on March 9, 2010. This ordinance was passed approximately one month after the Cherokee Indian resolution and at a time when county residents were distressed over the construction of the Hyatt Tie Station. It is entitled "An Ordinance Establishing A Moratorium on Issuance of Swain County Building and Soil and Erosion Control Permits for the Construction of Telecommunication Towers and Utility Substations, Tie-In Stations, and Switching Stations and Any and All Buildings and Structures Associated Therewith Pursuant to N.C. Gen. Stat. §153A-340(h) and N.C. Gen. Stat. §153A-121" (Ordinance). In summary, the Ordinance cited the statutes referenced in the title as creating authority in the county to define and regulate conditions that are detrimental to the health, safety and general welfare of the county's citizens. It further stated that the scenic and unspoiled areas of Swain County have become "critical to the county's tourism industry, economic growth, jobs and development." The Ordinance was expressly applicable to "utility substations, tie-in stations, and switching stations and other structures and buildings associated therewith in Swain County that create visual appearances that threaten to destroy the scenic and unspoiled aesthetic features of the County and the quality of life." It stated that the Board of Commissioners and County's staff needed a reasonable period of time in which to consider adoption of a permanent ordinance or regulations addressing the construction of telecommunication towers and utility substations, tie-in stations, switching stations and buildings and structures associated therewith. The Ordinance established a 90-day moratorium on the issuance of building permits and soil and erosion permits for those projects in Swain County. Although Duke asserts that the Ordinance is preempted by the Commission's state-wide authority over transmission line siting, the Commission determines that it need not reach the issue of preemption in this case because the Commission resolves the disputes between the parties on other grounds.

Duke witness Morgan testified that Duke originally planned to terminate the 161-kV portion of the transmission line at the proposed Hyatt Tie Station, but when controversy arose about placing a tie station in the Kituwah Valley, Duke abandoned its plans for the Hyatt Tie Station and chose instead to build the Swain Tie Station in the Swain County Industrial Park and terminate the 161-kV portion of the transmission line there. In so doing, Duke voluntarily agreed to meet a major objective Complainant sought in this docket.

The Commission concludes that Complainant has failed to show that Duke acted unreasonably and inappropriately in placing the steel lattice towers within Duke's existing right-of-way at locations where wooden poles already were in place. In addition, Duke made reasonable and appropriate efforts to reduce the visual impact of the towers. Although Property Owner Complainants had a mostly unobstructed view before the towers were constructed, and although, as illustrated by the photographs introduced into evidence, the steel lattice towers create adverse visual and property enjoyment impacts that cause a diminution in the value and enjoyment of their homes, Complainant has offered no evidence that Duke's replacement steel towers or poles were not located in valid and appropriately recorded easements. Complainant has offered no evidence that the easements limited the height, location or mode of construction of facilities within the easements. Complainant has not appropriately responded to Duke's evidence that the 161-kV line must be elevated above the height of the 66-kV line. It has not identified any suitable alternative locations where the replacement structures should have been located. Complainant has not presented evidence that relocation of the replacement vertical structures would not have adverse visual and property enjoyment impacts on other property owners. While Property Owner Complainants understandably are disappointed that views are diminished and expectations unfulfilled, they or their predecessors in interest acquired property encumbered or affected by easements or granted easements that created the rights Duke is exercising on behalf of the using and consuming public. While they assumed that the less visually intrusive wooden poles would not be replaced with taller structures, they have failed to present evidence that these assumptions were based on terms of the easements, representations by Duke, or any independent investigation that would justify this assumption.

Duke replaced wooden poles numbered 65 through 74 at a time when it intended to construct the tie station at the Hyatt Creek site or at a site located nearby. Although Duke's decision to change the location of the tie station to the Swain County Industrial Park location postpones the immediate need for the replacement of the ten poles for Duke's fully intended purpose at the time of replacement, no evidence has been presented that Duke's decision to replace them when it did was unreasonable. Duke's evidence is that time was of the essence. In anticipation of arguments that the relocation of the tie station postpones the current need for the upgraded structures to support a 161-kV line, Duke witness Morgan testified that the transmission towers east of the Swain Tie Station now support two 66-kV circuits, and these circuits are needed to maintain the reliability of service in the Bryson City, Gateway and Cherokee areas. If Duke were to remove the steel towers and put back the old wooden pole line, each customer in these areas would be served from a single transmission line. In the event of damage to the line from a storm or logging accident, or to the wooden poles from woodpeckers, there would be a loss of service in all of these areas. Having a second circuit available increases the reliability of service for these customers. Moreover, if the wooden poles were reinstalled, the line would likely reach its capacity within ten years, and require installation of a double-circuit line at that time. Morgan also stated that removing the steel towers and then putting them back when the 161-kV line became necessary would be needlessly expensive.

Under G.S. 62-75, Complainant has the burden of proof. The Commission determines that Complainant has failed to provide sufficient evidence that Duke acted unreasonably in upgrading structures numbered 65-74 when it did in anticipation of constructing the tie station at the Hyatt Creek site. To meet its burden of proof, Complainant would have been required to show that Duke's decision to replace the ten poles was unreasonable at the time made based on the information available to Duke at that time. Complainant has failed to meet this burden. As the upgraded facilities are currently useful in providing enhanced, more reliable service, the Commission determines that no justification exists for taking the ten steel towers down and putting wooden poles back in their place at considerable additional costs. Indeed, the reason the ten structures will not be used to support a 161-kV line now is because Duke has agreed to abandon the Hyatt Tie Station, responsive to a primary assertion Complainant advanced in this action. Consequently, Complainant has failed to meet its burden of proof in showing that Duke's refusal to reinstall the wooden poles once replaced is unreasonable. The 161-kV line from the Swain Tie Station to the East Bryson Tap is justified as back-up capacity to maintain the reliability of service in the Bryson City, Gateway and Cherokee areas, and the 66-kV circuit likely will reach its capacity in ten years.

As a public utility, Duke has the right of eminent domain. Duke has the responsibility to provide reliable and adequately priced service in its assigned service area. To fulfill this obligation, Duke has been granted the authority to diminish or extinguish the property rights of individual property owners for the broader interest of the using and consuming public. Similarly, in this case Duke has upgraded a line for the benefit of the many in its service area to the detriment of the few. Duke must exercise these rights in reasonable and responsible ways, and the Commission can provide relief to aggrieved property owners in the appropriate case. However, due to the deficiencies in the Complainant's evidence cited above, the Commission determines that Complainant has failed to make a case for such relief here.

To the extent Property Owner Complainants are entitled to any relief as a result of Duke's actions, and the Commission expresses no opinion on whether they are, the Commission determines that the remedy is not one available in this forum where an award of damages is unavailable, but in the General Court of Justice where actions for additional encumbrances on property in the nature of inverse condemnation are permitted.

The principle that a public utility's decision about the siting and construction of a transmission line is reviewable by the Commission was established in Kirkman v. Duke Power Co., 64 N.C.U.C. 89, 94 (1974). In that case the Commission stated:

> It is ... basic law in this State that the grant of franchise to a public utility carries with it the requirement of reasonable conduct in the discharge of its business functions. No public utility may, under the cloak of franchise, act arbitrarily and unreasonably in the conduct of its business and in the providing of its service to the public without being answerable to the law or the jurisdiction. Assuming such arbitrary and unreasonable acts on the part of the public utility in the providing of its service to the public or to individual citizens, the proper forum for the consideration of such matters may be either this Commission or the General Court of Justice, depending upon the nature of the complaint and the relief sought in this matter. The nature of this complaint is that the Defendant, Duke Power Company, has acted or proposes to act in an unreasonable and arbitrary manner in the construction of an electric transmission line, the purpose of which is to provide

> electric service to individual citizens and the public in general in North Carolina, and the relief sought is an order to alter the plans of Duke Power Company for the construction of said line and to require that the proposed transmission line be constructed in a different manner and particularly in a different place. This is the proper forum for the consideration of such a complaint.

The Commission previously held, in its Summary Judgment Order, that Complainant had raised an issue of material fact and was entitled to an evidentiary hearing on the question of whether Duke "acted in a reasonable and appropriate manner in its siting and construction of the transmission line upgrade."

There are two statutes of particular importance in cases involving a review of transmission siting and construction decisions. The first is G.S. 113A-3, North Carolina's Environmental Policy Act, which states that "[i]t shall be the policy of the State to seek, for all of its citizens, safe, healthful, productive and aesthetically pleasing surroundings; to attain the widest range of beneficial uses of the environment without degradation, risk to health or safety; and to preserve the important historic and cultural elements of our common inheritance." The second statute is G.S. 62-2(a)(5), which provides that it is the policy of the State "[t]o encourage and promote harmony between public utilities, their users and the environment."

In Gwynn Valley, Inc. v. Duke Power Co., 78 N.C.U.C. 186 (1988), the Commission applied these two statutes. The complainant operated Camp Gwynn Valley, a camp for children that was located near Brevard in Transylvania County. The camp had been in operation for 46 years. Because of growth in Transylvania County, Duke planned to build a substation in the Rich Mountain-Connestee Falls area and a 44-kV transmission line that would pass through or near the camp. Duke proposed to purchase an easement near the northern boundary of the camp. When the camp refused to grant the easement, Duke began condemnation proceedings in Superior Court. The complainant sought an order from the Commission prohibiting Duke from proceeding with the condemnation action. Following an evidentiary hearing, the Commission found that the area in question included a hillside or upland meadow used by the camp for Sunday vespers, sunset viewing, horseback riding and similar purposes. The construction of the proposed line would significantly impact the camp's activities, especially Sunday vespers, because there was no other place on the camp property with a panoramic view of the setting sun. At the hearing the camp put forth three possible alternatives to Duke's proposed route for the transmission line. Each of these had advantages and disadvantages in comparison with Duke's proposal. One of them was described by Duke as the "best route," but it would have required the condemnation of a tract of land that Duke preferred not to condemn.

In Gwynn Valley, the Commission pointed out that G.S. 113A-3 is closely modeled after the National Environmental Policy Act. The Commission noted that in cases involving the National Environmental Policy Act, the federal courts have required an administrative agency to "take a 'hard look' at the environmental consequences of the proposed action and of any reasonable alternatives thereto." 78 N.C.U.C. at 199, citing Kleppe v. Sierra Club, 427 U.S. 390, 410 n.21 (1976), and Natural Resources Defense Council v. Morton, 458 F.2d 827, 838 (1972). Thus, the Commission concluded that it must take a hard look at the environmental consequences of Duke's proposed action in deciding whether Duke was acting arbitrarily or unreasonably.

The Commission held "that there is not sufficient evidence to enable it to take a 'hard look' and evaluate the alternatives in order to determine if they are environmentally less damaging than the proposed line siting across the Camp. Nor is the Commission satisfied that Duke itself has taken a sufficiently 'hard look' at the alternatives proposed by the Camp ...." 78 N.C.U.C. at 200. The Commission, therefore, ordered Duke to conduct a study of "the alternatives recommended by the Camp – or any other alternative routing which Duke may choose to examine – and evaluate the environmental consequences of the alternatives as compared with the proposed siting across Camp Gwynn Valley, the costs of the alternatives, and the ability of Duke to efficiently serve its load over the alternative routes." Id. Duke was directed to complete the investigation and file a report with the Commission within six months. In addition, the Commission requested that Duke request a stay of the condemnation proceeding in Superior Court while Duke completed its investigation.

Gwynn Valley is distinguishable from the present case in three important respects. First, in Gwynn Valley Duke was seeking to condemn property for use as a transmission right-of-way that had never before been dedicated to public use and that was used by its owners for a unique purpose. In the present case, Duke owns the right-of-way on which it upgraded the Wests Mill Transmission Line and has used it to serve the public for many decades. Second, the complainant in Gwynn Valley proposed an alternative route for the transmission line, a route that Duke rejected merely because it would require condemnation of land that Duke preferred not to condemn. In the present case, Complainant offered no evidence of an alternative route for the upgrade project. As Complainant stresses, scenic views in the mountains are coveted. For Duke to select an alternative route, interfering with the viewscape of property owners whose property had never been encumbered by easements, would not have provided a suitable alternative. Finally, unlike in Gwynn Valley, the evidentiary hearing required and undertaken by the Commission over Duke's objection in the present case produced sufficient evidence for the Commission to take a "hard look" at the environmental consequences of Duke's decision to construct the transmission line upgrade. Based on that hard look, the Commission concludes that the adverse visual and property enjoyment impacts upon Property Owner Complainants and others in the project area, though understandably of concern to Property Owner Complainants, are a necessary, reasonable and appropriate result of the need to upgrade the transmission line. Therefore, the Commission concludes that the upgrade project, and in particular the steel lattice towers used in the upgrade project, do not harm the environment in violation of the public policies established in G.S. 113A-3 and G.S. 62-2(a)(5).

The Commission concludes that Complainant has not proven by a preponderance of the evidence that Duke acted in an unreasonable or inappropriate manner in its siting and construction of the upgrade of the Wests Mill Transmission Line and in refusing to reinstall wooden poles in place of towers 65-74. Nevertheless, the Commission emphasizes that a public utility does not have an unlimited right to build whatever transmission line structures it chooses on its existing right-of-way. The utility must act in a reasonable and appropriate manner in its siting and construction of the transmission line.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT 19

The evidence supporting this finding of fact appears in the testimony of Complainant witnesses Wolf, Proctor, Simon and Roland and Duke witnesses Robinson and Morgan.

Complainant witness Wolf testified regarding his concerns about adverse health impacts from electromagnetic fields due to the close proximity of the transmission line. Complainant witness Roland testified to similar concerns, in particular with respect to his children's health. Complainant witnesses Proctor and Simon testified to similar concerns, as well as the fact that Proctor is dependent on a heart pacemaker. Proctor testified that she had knowledge of warnings by medical providers and pacemaker manufacturers that magnetic equipment can be detrimental to pacemakers.

Duke witness Robinson testified that Duke utilized standard, safe, reliable and cost-effective transmission line according to the voltage of the upgraded line.

Duke witness Morgan testified that Duke conducted simulation studies on the electromagnetic field of the upgraded transmission line. Duke studied five data points under the line for each house along the line. The data points were under the center of the tower, fifty feet to each side of the tower, which is along the right-of-way line, and fifty feet beyond each side of the right-of-way line. The electromagnetic fields were found to be negligible in comparison to appliances inside a house. Duke also used a transmission line conductor suitable for the altitude and fog conditions in the area to minimize the amount of line noise.

Complainant has not shown by a preponderance of the evidence that the upgraded transmission line creates the potential for adverse health effects. While allegations concerning health effects are not to be taken lightly, Complainant's testimony leaves to speculation whether any adverse electromagnetic field or other conditions result from this transmission line upgrade. On the other hand, Duke's evidence demonstrates that Duke tested for potential adverse effects and found none present. Therefore, the Commission concludes that Complainant has not carried its burden of proof on this matter.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT 20

The evidence supporting this finding of fact appears in the testimony of Complainant witnesses Wolf and Roland.

Complainant witness Wolf testified that the transmission towers are an accident waiting to happen. There are several young children in his family, and many other children in the neighborhood, and no matter how often parents warn that climbing the towers is dangerous, sooner or later a child will try to climb one of them and suffer an injury.

Complainant witness Roland testified that he has an infant daughter and that as she grows older he is concerned that she, or some other child, might try to climb one of the towers and fall. Except for the difference in size, the appearance of the towers is similar to that of a jungle gym. On cross-examination, he stated that a large fence could deter a child from playing on a transmission tower, but the better solution would be to remove the towers and put back the wooden poles.

North Carolina law recognizes the attractive nuisance doctrine, which provides that a landowner may be liable for injury to a child caused by a structure or condition on his property that attracts and is dangerous to children because of their inexperience and lack of mature judgment. See Strong's North Carolina Index 4th, "Negligence," § 63; Graham v. Sandhill Power

Co., 189 N.C. 381, 127 S.E. 429 (1925) (jury award upheld in favor of 14 year old child who was severely injured by contact with uninsulated electric lines carrying 11,000 volts while playing on top of a sawdust pile on which children frequently played).

However, Complainant has not cited any North Carolina authority in which electric transmission towers have been held to be attractive nuisances, and the Commission has found no such authority. Accordingly, the Commission declines to hold that these particular transmission towers and poles are attractive nuisances, or that Duke is required to place a fence around each tower and pole to prevent access by children.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT 21

The evidence in support of this finding of fact can be found in the testimony of Complainant witness Wolf and Duke's panel of witnesses.

Complainant witness Wolf testified that during the construction of the transmission tower near his home he regularly found human feces on his property in a children's play area. This occurred 12 to 15 times. He believes the construction crew was responsible because it occurred during the construction period, and he does not know how else it could have happened. Duke and its contractor did not provide any portable toilet facilities for the construction workers.

Duke witness Hollifield testified that Duke had men working at several different sites while putting up the towers and there was not a portable toilet at every site, but the employees at any site could be taken by vehicle to the site where the portable toilet was located.

Complainant has not established by a preponderance of the evidence that Duke's employees or its contractor's employees were responsible for these acts. The Commission strongly disapproves of indecent conduct by any employee or contractor of a public utility. Utilities must ensure that their employees and employees of their contractors have access to toilet facilities and use them appropriately. However, Complainant's testimony leaves to speculation who was responsible for the incidents described. Therefore, the Commission concludes that Complainant has not carried its burden of proof on this matter.

CONCLUSIONS

After careful consideration of the testimony and exhibits introduced at the hearings, the entire record in this proceeding and the applicable legal standards, the Commission concludes that Complainant has not carried its burden of proof to show that Duke acted unreasonably and inappropriately in its decisions and actions concerning the upgrade of the Wests Mill Transmission Line. Further, as the Commission held in its Summary Judgment Order, the Commission does not have the authority to award monetary damages for diminution in the value of the property of Complainant's members resulting from the upgrade of the transmission line. Complainant's members will need to pursue that remedy in the appropriate court. Duke has voluntarily agreed to abandon the Hyatt Tie Station, rendering unnecessary the need for the Commission to rule on Complainant's requests with respect to the location thereof. With respect to Complainant's other claims not already addressed by earlier orders, the relief Complainant seeks is denied.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the _28th_ day of December, 2011.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Lg122811.01

DOCKET NO. E-2, SUB 993

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Progress Energy Carolinas, Inc., for Registration of a New Renewable Energy Facility	) ORDER ACCEPTING) REGISTRATION OF RENEWABLE) ENERGY FACILITY

BY THE CHAIRMAN: On January 27, 2011, Progress Energy Carolinas, Inc. (PEC), filed a registration statement pursuant to Commission Rule R8-66 for a new renewable energy facility located in Marshall in Madison County, North Carolina. PEC stated that its 5 MW hydroelectric power facility, Marshall Hydroelectric Plant, had been operational since 1911.

The filing included certified attestations that: 1) the facility is in substantial compliance with all federal and state laws, regulations, and rules for the protection of the environment and conservation of natural resources; 2) the facility will be operated as a new renewable energy facility; 3) PEC will not remarket or otherwise resell any renewable energy certificates (RECs) sold to an electric power supplier to comply with G.S. 62-133.8; and 4) PEC will consent to the auditing of its books and records by the Public Staff insofar as those records relate to transactions with North Carolina electric power suppliers.

On February 15, 2011, the Public Staff filed the recommendation required by Commission Rule R8-66(e) stating that PEC's registration statement as a new renewable energy facility should be considered to be complete. No other party made a filing with respect to these issues.

In its July 31, 2009 Order Accepting Registration of Renewable Energy Facilities, in Docket No. E-7, Subs 886, 887, 888, 900, 903 and 904, the Commission concluded that six single-unit hydroelectric power facilities, each with a capacity of 10 MW or less, sought to be registered by Duke Energy Carolinas, LLC, as new renewable energy facilities qualified only as renewable energy facilities. As noted in that Order, G.S. 62-133.8(a)(7) defines "renewable energy facility," in relevant part, as "a facility, other than a hydroelectric power facility with a generation capacity of more than 10 megawatts, that ... [g]enerates electric power by the use of a renewable energy resource." "Renewable energy resource" specifically includes hydropower. Thus, the definition of renewable energy facility includes a utility-owned hydroelectric power facility with a generating capacity of 10 MW or less. PEC's Marshall Hydroelectric Plant, a hydroelectric power facility with a generating capacity of less than 10 MW, meets the statutory definition of a renewable energy facility.

G.S. 62-133.8(a)(5) defines "new renewable energy facility" as follows:

(5) "New renewable energy facility" means a renewable energy facility that either:
   a. Was placed into service on or after January 1, 2007.
   b. Delivers or has delivered electric power to an electric power supplier pursuant to a contract with NC GreenPower Corporation that was entered into prior to January 1, 2007.

c. Is a hydroelectric power facility with a generation capacity of 10 megawatts or less that delivers electric power to an electric power supplier.

In its June 17, 2009 Order in Docket No. E-100, Sub 113, the Commission stated that, "with regard to existing hydroelectric power facilities with generation capacity of 10 MW or less, the Commission agrees with the Public Staff that the 'delivery' requirement of G.S. 62-133.8(a)(5)(c) excludes such facilities from the definition of new renewable energy facility." Consistent with the Commission's determination in its June 17, 2009 Order, PEC's Marshall Hydroelectric Plant does not meet the statutory definition of a new renewable energy facility.

In its cover letter, PEC states that it is seeking to register its Marshall Hydroelectric Plant "[i]n order to utilize cost-effective hydroelectric renewable energy resources towards compliance with the North Carolina Renewable Energy and Energy Efficiency Portfolio Standard (REPS)." In its June 17, 2009 Order, the Commission further concluded (1) that an electric public utility may not use power generated at its own hydroelectric power facilities to meet its REPS requirement pursuant to G.S. 62-133.8(b)(2)(b) and (2) that an electric public utility is limited, pursuant to G.S. 62-133.8(b)(2)(a), to using power generated at a new renewable energy facility for REPS compliance. PEC, therefore, may not count toward REPS compliance hydroelectric power generated at its Marshall Hydroelectric Plant or the associated RECs. Under G.S. 62-133.8(c)(2), electric membership corporations and municipalities may, in meeting their REPS requirements, "[p]urchase electric power from a renewable energy facility or a hydroelectric power facility ..." or "[p]urchase renewable energy certificates derived from in-State or out-of-state renewable energy facilities ...."

Based upon the foregoing and the entire record in this proceeding, the Chairman finds good cause to accept registration of PEC's hydroelectric power facility as a renewable energy facility, but not as new renewable energy facility. PEC shall annually file the information required by Commission Rule R8-66 on or before April 1 of each year. PEC will be required to participate in the NC-RETS REC tracking system in order to facilitate the issuance of RECs.

IT IS, THEREFORE, ORDERED as follows:

1. That the registration by PEC for its hydroelectric power facility, Marshall Hydroelectric Plant, located in Marshall in Madison County, North Carolina as a renewable energy facility shall be, and hereby is, accepted.

2. That PEC shall annually file the information required by Commission Rule R8-66 on or before April 1 of each year.

ISSUED BY ORDER OF THE COMMISSION.
This the 1st day of April, 2011.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

k2040111.01

DOCKET NO. E-2, SUB 993

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Progress Energy Carolinas, Inc.,	)	
for Registration of a New Renewable Energy	)	ERRATA ORDER
Facility	)	

BY THE CHAIRMAN: On April 1, 2011, the Commission issued an Order Accepting Registration of Renewable Energy Facility in the above-captioned docket. On April 6, 2011, the Commission inadvertently issued a second, identical Order. That second Order, issued on April 6, 2011, was in error and should be rescinded. The Order Accepting Registration of Renewable Energy Facility issued on April 1, 2011, should remain in effect.

IT IS, THEREFORE, ORDERED that the Order Accepting Registration of Renewable Energy Facility issued on April 6, 2011, shall be, and hereby is, rescinded, and that the Order Accepting Registration of Renewable Energy Facility issued on April 1, 2011, shall remain in effect.

ISSUED BY ORDER OF THE COMMISSION.
This the 5th day of May, 2011.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

sw050511.01

DOCKET NO. E-7, SUB 819

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Carolinas, LLC, for Approval of Decision to Incur Nuclear Generation Project Development Costs	)))	ORDER APPROVING DECISION TO INCUR LIMITED ADDITIONAL PROJECT DEVELOPMENT COSTS

HEARD: Tuesday, March 15, 2011, at 9:00 a.m., Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman Edward S. Finley, Jr., Presiding; Commissioners Lorinzo L. Joyner, William T. Culpepper, III, Bryan E. Beatty, and ToNola D. Brown-Bland

APPEARANCES:

For Duke Energy Carolinas, LLC:

Robert W. Kaylor, Law Office of Robert W. Kaylor, P.A., 3700 Glenwood Avenue, Suite 330, Raleigh, North Carolina 27612

Timika Shafeek-Horton, Deputy General Counsel, Duke Energy Corporation, 526 South Church Street, EC03T/Post Office Box 1006, Charlotte, North Carolina, 28201-1006

Charles A. Castle, Senior Counsel, Duke Energy Corporation, 526 South Church Street, EC03T/Post Office Box 1006, Charlotte, North Carolina, 28201-1006

For Public Advocacy Groups:

John Runkle, Attorney at Law, Post Office Box 3793, Chapel Hill, North Carolina 27515

For the Using and Consuming Public:

Gisele L. Rankin, Staff Attorney, Public Staff-North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

Leonard G. Green, Assistant Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602-0629

BY THE COMMISSION: On November 15, 2010, Duke Energy Carolinas, LLC (Duke or the Company), filed an Amended Application for Approval of Decision to Incur Nuclear Generation Project Development Costs. By this application, Duke seeks authority to incur additional project development costs of up to $229 million for the period January 1, 2010, through December 31, 2013, for a total of $459 million for the Company's proposed Lee Nuclear Station in Cherokee County, South Carolina. Duke filed this application pursuant to G.S. 62-60, G.S. 1-253, G.S. 62-2, and G.S. 62-110.7.

In response to the application, the Commission issued an Order on November 29, 2010, scheduling it for hearing to begin on March 15, 2011, and requiring the prefiling of testimony. The Order stated that parties who had previously intervened did not need to seek additional leave to intervene; their status as intervenors continued. Those who had filed petitions to intervene included Carolina Utility Customers Association, Inc., Carolina Industrial Group for Fair Utility Rates III, and the Public Advocacy Groups (the Groups).[1] The Attorney General's previously-filed notice of intervention pursuant to G.S. 62-20 was recognized, and the intervention of the Public Staff was recognized pursuant to Commission Rule R1-19(e).

On December 6, 2010, Duke filed a revised amended application stating that it "estimates incurring project development costs of up to $287 million for a total of $459 million."

The matter came on for hearing as scheduled. The following testified as public witnesses and generally in opposition to Duke's application: Senator Eleanor Kinnaird, Richard Fireman, Avram Friedman, Lewis Patrie, William Kinsella, Kendall Hale, Jean Larson, Beth Henry, Pat Moor, Bob Jackson, Harry Phillips, and Hope Taylor.

Duke then presented the direct testimony of James E. Rogers, Chairman, President, and Chief Executive Officer of Duke Energy Corporation; Dhiaa M. Jamil, Group Executive and Chief Generation Officer for Duke Energy Corporation and Nuclear Officer for Duke; and Janice D. Hager, Vice President, Integrated Resource Planning and Regulated Analytics for Duke Energy Business Services. Duke also presented the rebuttal testimony of witnesses Rogers, Jamil, and Hager. The Groups presented the testimony of Peter A. Bradford, an adjunct professor at Vermont Law School and President of Bradford Brook Associates. The Public Staff presented the joint testimony of Michael C. Maness, an Assistant Director of the Accounting Division of the Public Staff, and Kennie D. Ellis, Utilities Engineer with the Electric Division of the Public Staff.

On April 5, 2011, Duke filed a late-filed exhibit correcting the projected total allowance for funds used during construction (AFUDC) for the Lee Station for the time period from 2011 through 2013. The corrections reduced the total AFUDC from $128 million to $124 million, which reduced the total estimate of project development costs from $459 million to $455 million.

On May 3, 2011, Duke filed a notice of acceptance stating that its proposed order would adopt the Public Staff's pre-filed position that the Company's decision to incur additional project development costs of up to $120 million from January 1, 2011, through June 30, 2012, for the proposed Lee Station is reasonable and prudent. The filing also stated that Duke continues to maintain that its decision to incur costs during 2010 was reasonable and prudent.

Based on the evidence presented at the hearing, and the entire record in this proceeding, the Commission makes the following

[1] The Groups include the following intervenors: N.C. Waste Awareness and Reduction Network (NC WARN), Public Citizen, the North Carolina Public Interest Research Group, the Nuclear Information and Resource Service, Common Sense at the Nuclear Crossroads, and the Blue Ridge Environmental Defense League.

ELECTRIC – MISCELLANEOUS

FINDINGS OF FACT

1. Duke is a public utility providing electric utility service to customers in its service area in North Carolina subject to the Commission's jurisdiction.

2. The Commission has jurisdiction over this application pursuant to G.S. 62-110.7, which allows a utility to request, at any time prior to the filing of an application for a certificate to construct a nuclear generating facility to serve North Carolina retail customers, that the Commission review the public utility's decision to incur project development costs.

3. Through December 31, 2009, Duke had incurred nuclear project development costs of approximately $172 million. Duke's application in this proceeding, as revised, requests Commission approval of its decision to incur the project development costs necessary to continue development work from January 1, 2010, through December 31, 2013, of up to $283 million, for a total of $455 million through December 31, 2013.

4. The planning environment for electric utilities has been characterized for some time by uncertainties related to the effectiveness of new demand-side management (DSM) and energy efficiency (EE) programs; whether carbon legislation will be enacted and, if it is, what form it will take and at what cost; whether and how much renewable energy will become available; and how well renewable technologies can be integrated into a utility's resource mix. The following have been added to these uncertainties: whether North Carolina will enact legislation that will allow Duke's rates to "track" construction work in progress (CWIP) in a manner similar to legislation that has already been passed in South Carolina; the amount of load lost due to the recession that will not return and the extent to which growth in customer demand will occur as the economy improves; and any effect from the nuclear plant failures in Japan resulting from the earthquake and tsunami on March 11, 2011, on the timing and the construction costs of future nuclear plants and the costs related to spent nuclear fuel storage.

5. Of particular importance is the uncertainty as to the date in the future when Duke would need a nuclear unit to be on line. Duke's projected need in its 2006 filing in this docket for nuclear baseload generation was 1,734 MW by 2016. In its late 2007 filing, Duke had reduced the initial need to one 1,117 MW unit and delayed it until 2018. At that time, the Company anticipated filing for a certificate with the South Carolina Public Service Commission (SCPSC) in late 2008. Duke's projected need for the first unit has now been moved out to 2021, and the certificate application filing with the SCPSC is not expected until 2013.

6. Assumptions about carbon legislation have a significant effect on whether and when new nuclear units become part of the optimal resource mix under Duke's planning process. An assumption of no carbon regulation makes portfolios with no new nuclear look best, while an assumption of high CO_2 allowance prices makes a portfolio with two nuclear units look most cost-beneficial. Under Duke's reference case in the 2010 Integrated Resource Planning (IRP) proceeding, which assumed a cap and trade program with CO_2 prices based on the Waxman/Markey legislation delayed until 2015, two nuclear units in 2021 and 2023 were $1.8 billion more cost-effective than the natural gas-fired combustion turbine/combined cycle (CT/CC) portfolio. Under a no-carbon regulation scenario, the CT/CC portfolio was $3 billion more cost-effective than the two nuclear unit portfolio.

7. In Duke's IRP analysis, after selecting portfolios to test against sensitive input assumptions, in two out of four cases the portfolio that delayed nuclear until the 2026-2028 time frame proved more cost-effective than the portfolio that installed nuclear capacity for the 2021 time frame. Overall, the analysis showed that there is no difference in the present value of revenue requirements impact between completing the nuclear plant in the 2021-2023 time frame or in the 2026 time frame.

8. It is not appropriate at this time in this proceeding to approve any specific amount of nuclear project development costs nor is it appropriate to approve a cumulative amount from 2006 through 2013 as requested by Duke in its application.

9. It is appropriate for Duke to incur on and after January 1, 2011, only those nuclear project development costs that must be incurred to maintain the status quo with respect to the Lee Nuclear Station, including Duke's combined construction and operating license (COL) application at the Nuclear Regulatory Commission (NRC), up to a maximum of the North Carolina allocable portion of $120 million.

10. It is appropriate to require Duke to file and serve reports similar to the reports required by the Commission in the declaratory ruling order it issued in this docket on March 20, 2007, as more specifically described hereinafter.

11. Should Duke decide to cancel the Lee Nuclear Station prior to the issuance of a certificate, any approval granted by the Commission in this proceeding should not be considered to be approval to record any abandoned project development costs in a regulatory asset account. Any such treatment requires that an application be filed by Duke.

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

The evidence supporting these findings of fact is contained in the verified Application, the testimony in this docket, and the statutes and rules governing the authority and jurisdiction of the Commission. These findings are informational, procedural and jurisdictional in nature and are not contested by any party.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3 - 10

The evidence for these findings of fact is found in the testimony of Duke witnesses Rogers, Jamil, and Hager, the testimony of the Groups' witness Bradford, and the testimony of Public Staff witnesses Maness and Ellis.

Duke witness Rogers testified that the Company was seeking approval of its decision to incur total development costs of $459 million through December 31, 2013, for the proposed Lee Nuclear Station, and that the allocated North Carolina retail portion of those costs is approximately 68%. He stated that Duke was continuing with the development of the Lee Nuclear Station because the Company has an obligation to plan for and meet its customers' needs in a reliable and cost-effective manner in the face of the uncertainties surrounding future economic, environmental, regulatory, and operating circumstances. Mr. Rogers further testified that he believed that the Lee Nuclear Station will provide significant value to the customers in light of those uncertainties. He stated that the Lee Nuclear Station, along with other supply-side resources, as well as increased DSM, EE, and renewable energy resources, is a key component of Duke's strategic comprehensive modernization plan, which is designed to meet growing customer capacity and energy needs, as well as respond to changing regulatory circumstances, which have brought about commitments to retire approximately 1,667 MW of older, more polluting, and less efficient coal generating units.

Mr. Rogers further testified that the planned commercial operation date of the Lee Nuclear Station has been changed from 2018 to 2021, but that the Company still anticipates receiving a commercial operating license from the NRC by December 31, 2013, which is the basis for the date chosen for its approval request in this proceeding. He stated that with the very long lead time involved in developing and constructing nuclear generation facilities, there is a great deal of development work to be done and costs to be incurred in order to meet a commercial operations date in 2021. In fact, in order to obtain a COL in 2013, he stated that the Company will need to incur up to the $459 million of costs identified in its request for approval. Mr. Rogers stated that Duke is seeking approval of its decision to incur additional nuclear project development costs from 2010 through 2013 because seeking such approval is consistent with the legislation passed in North Carolina and South Carolina expressly providing for such approval, which also provides additional assurance of recovering nuclear construction-related financing costs. Mr. Rogers testified that, even with the approval requested in this proceeding, the Commission will retain significant oversight over the project development process, and that the Company was not asking the Commission to make any determination with respect to recovery of the costs incurred to develop the Lee Nuclear Station.

He further testified that, even with the uncertain future of carbon legislation, new nuclear generation resources are the right choice for Duke to make. He stated that new nuclear generation will operate at high capacity factors and provide carbon emission-free energy at relatively low fuel costs for over 50 years. He testified that Duke's current reliance on nuclear generation for over 5,000 MW of capacity and approximately 50% of its generated energy have provided the Company's customers with electric rates lower than the national average, giving the region a competitive advantage in attracting new jobs and businesses. He testified that, even if carbon legislation does not occur in the short term, it would be entirely unreasonable to ignore the fact that stringent regulation of carbon and other emissions will occur at some point. Therefore, he stated, the Company must retain and enhance the diversity of its generation resource portfolio, including new nuclear, natural gas, advanced coal, renewable, and DSM and EE resources.

With specific regard to the evolving market for natural gas, Mr. Rogers testified that Duke is taking a measured approach. He stated that, although prices for natural gas are forecasted to remain low over the near term, they have been historically subject to significant volatility, and questions remain as to access to newly discovered reserves of shale natural gas. Mr. Rogers stated that he believes that additional time is needed to assess the true achievable potential and market impact of these reserves. However, he testified that natural gas will certainly play a role in Duke's diverse future resource mix.

With regard to joint ownership opportunities for the Lee Nuclear Station, Mr. Rogers stated in his initial direct testimony that while Duke is currently developing the station on an independent basis, it is continuing to assess opportunities for joint ownership or financial arrangements that could benefit its customers. He testified that Duke strongly believes in a regional generation concept for new nuclear generation, which would share risk and smooth out the rate impact on customers of placing new plants into service by enabling the addition of capacity in smaller increments. However, Mr. Rogers added, Duke is well-positioned to, and can support the need for, the project on an independent basis. In supplemental testimony, Mr. Rogers stated that on February 1, 2011, Duke entered into an agreement with Jacksonville Electric Authority (JEA), a municipally-owned electric utility serving the city of Jacksonville, Florida, whereby JEA is granted an option to purchase an undivided ownership interest in the Lee Nuclear Station of between 5% and 20% of the station. In return for the option, JEA has agreed to pay Duke $7.5 million. Mr. Rogers stated that Duke views the sale of this option as a very positive development in the process of developing both the Lee Nuclear Station and the concept of regional generation. On cross-examination, Mr. Rogers agreed that JEA's option payment would be credited toward the Company's nuclear development costs.

In response to cross-examination, Mr. Rogers testified that the percentage of the Company's produced energy generated by nuclear power is approximately 50%. Mr. Rogers also agreed that if the two new natural gas combined cycle plants currently being built by Duke are placed into service, the percentage of Duke's energy produced by natural gas will still be less than, or perhaps close to, 10%. He further testified that he had asked certain Duke personnel to review Duke's history of building nuclear power plants in North Carolina and South Carolina and determine if there were lessons to be learned from the past that would make Duke smarter in the future. As a result of this review, Jim Turner, at that time a group vice-president with the Company, provided Mr. Rogers with an e-mail (identified in this proceeding as Public Advocacy Groups Rogers Cross-Examination Exhibit No. 2) that stated that it would not be unreasonable to assume and plan for costs of building a plant using the AP1000 design to be as high as 40%-50% above the then current estimates. Mr. Rogers testified, however, that he did not agree with Mr. Turner's assessment because by the time Duke constructs the Lee Nuclear Station, there will already be reference plants built by SCANA Corporation, Southern Company, and by the Chinese which will provide tracking or comparison points for construction and construction costs.

Mr. Rogers further testified in response to cross-examination that there are several key factors under consideration by Duke to determine if the Company will proceed with construction of the Lee Nuclear Station. One factor is the Company's need for legislation in North Carolina that will allow the Company's rates to "track" CWIP, as already allowed in South Carolina. A second key factor is the extent and timing of the growth in customer demand as the economy improves. Mr. Rogers testified that he believes the economy will recover and that growth in demand will be significant, resulting in need for the plant. He further stated that the Company will not proceed with construction absent a CWIP financing statute being enacted in North Carolina. However, he stated that it is prudent for the Company to proceed with development at this time because he believes that North Carolina will ultimately approve such legislation. Furthermore, Mr. Rogers testified that if the North Carolina legislature ultimately does not enact such legislation, it is saying no to nuclear in the future in this state.

Duke witness Jamil's testimony recommended that the Commission grant the application for approval of the decision to incur up to $459 million in nuclear generation project development costs through the end of 2013. He also stated that the Lee project development work included site selection, selection of the Westinghouse AP-1000 NRC-certified design, and work on design changes to this design to close out a number of follow-up items identified in the initial design certification. This design certification amendment process is on schedule for approval by October 2011. He further testified that the Company has also responded to over 800 requests for additional information in ongoing communication with the NRC to support the review of the COL.

Mr. Jamil described planned project development work as including pre-construction and site preparation, continued communication with the NRC to prepare a draft environmental impact statement, and a draft safety evaluation report. The NRC is also scheduled to hold public hearings in South Carolina in mid-2011, and to hold mandatory evidentiary hearings in 2012. The Company also plans to submit the application for a certificate of public convenience and necessity, and a base load review order to the SCPSC, in addition to the application for cost recovery for an out-of-state baseload facility to this Commission. In addition, Mr. Jamil testified that the purchase of some transmission rights-of-way, a training simulator, and other long lead time equipment reservations were planned, but had been delayed due to the postponement of the planned operation dates of the proposed facility as described by witness Hager. Other planned project development work includes operational planning, supply chain, construction planning and detailed engineering work.

Mr. Jamil testified that it is important to continue development efforts without delay through the 2013 time frame in order to preserve the option to have the Lee Nuclear Station available to serve customers in the 2021 time frame.

Duke witness Janice Hager presented direct testimony regarding how the Duke 2010 IRP supports the Company's decision to continue development of the Lee Nuclear Station. Ms. Hager testified that Duke's IRP process begins with a 20-year forecast of summer and winter peak demands, as well as of energy use. Additionally, data are gathered regarding Duke's existing supply-side and demand-side capacity and energy resources, as well as the costs of possible additional resource options. The Company conducts quantitative analyses to identify options that will meet customer needs (including a reserve margin of 17% in the 2010 IRP) while minimizing costs, selecting potential portfolios that can be tested under baseline assumptions and with certain sensitive assumptions altered (sensitivities). Ms. Hager stated that, in addition to quantitative analysis, Duke also takes into consideration qualitative factors, such as fuel diversity, Duke's environmental profile, the stage of technology deployment, and regional economic development. Ms. Hager stated that the objective of the IRP is to inform the Company's decision-making over the short and long term to ensure that there is a safe, reliable, and reasonably priced supply of electricity to meet customer needs, even in the face of uncertainty. Duke believes that prudent planning requires a plan that is robust under many possible future scenarios, and that it is also important to maintain flexibility to respond to different potential outcomes.

Ms. Hager testified that Duke's existing generation portfolio totals over 21,000 MW of generation capacity. This capacity is split into approximately equal components of (1) nuclear, (2) coal, and (3) hydroelectric and natural gas, with nuclear and coal generation providing approximately 50% and 40% of the generated energy, respectively. She indicated that the 2010 IRP assumes retirement by 2015 of 370 MW of 1960s vintage combustion turbines and, pursuant to the Commission's Order in Docket No. E-7, Sub 790, as well as proposed federal requirements, the retirement of 1,667 MW of non-scrubbed coal generation.

Ms. Hager further testified that Duke's current load forecast reflects a 1.8% average annual growth rate in both summer and winter peak demand, and a 2.0% average annual growth rate in total energy usage over a twenty-year planning horizon. Additionally, the Company must take into account that some currently existing resources will no longer be available over the planning horizon. Taking these factors, as well as certain others, into consideration, Ms. Hager testified that Duke's need for additional capacity would reach 2,200 MW by the year 2020, and 6,000 MW by 2030. She stated that Duke plans to meet this projected need with a diverse portfolio of resources, including traditional and renewable generation, as well as demand response and EE resources. She testified that there are essentially two types of supply-side resources available at this time to meet the growth in load that will not be provided by DSM and EE resources: natural gas and nuclear. She stated that the Company views natural gas as a component of the long-term supply-side solution, but not the sole answer. In addition, the Company views a diverse portfolio of resources, including natural gas and nuclear, to be best, in that it will allow Duke to balance the risk of fuel volatility and minimize costs to customers over the long term. She testified that, even with the Lee Nuclear Station, the percentage of nuclear capacity and energy expected in 2030 would remain the same as it is in 2011.

Ms. Hager testified that the projected costs of natural gas is a key input into the Company's IRP analysis. She stated that projected costs have dropped significantly over approximately the last year, mainly due to expectations regarding the availability of domestic shale natural gas. She stated, however, that questions remain regarding access to shale gas, and thus uncertainty exists regarding the long-term availability and pricing of natural gas. However, she indicated that natural gas resources are a part of Duke's planned-for diversified energy mix.

Ms. Hager testified that in the 2010 IRP, Duke considered a range of possible carbon allowance prices, consistent with Duke's expectation for a carbon-constrained future. To determine the range of prices to be considered in the IRP, Duke utilized various federal cap and trade proposals, as well as a possible non-cap and trade approach involving a federal clean energy standard.

With respect to the Company's baseline projected load impacts for EE and DSM resources, Ms. Hager testified that these were based on the settlement regarding Duke's Energy Efficiency Plan reached in Docket No. E-7, Sub 831, which incorporates impacts measured at 85% of the targets set forth in the settlement. For purposes of the 2010 IRP, Duke assumed that total efficiency savings will continue to grow through 2021. Additionally, Ms. Hager testified that Duke developed a high impact scenario using 100% of the settlement targets for five years and then an annual increase of 1% of retail sales until the impacts reach the economic potential set forth in the 2007 market potential study.

Ms. Hager testified that in the 2010 IRP, Duke modified its consideration of renewable energy resources due to North Carolina's enactment of the Renewable Energy and Energy Efficiency Portfolio Standard (REPS). In addition to explicitly incorporating the impact of the REPS on North Carolina retail sales, Duke included the same requirements for all sales, retail and wholesale, to take into account the possibility of a Federal Renewable Standard.

In conclusion, Ms. Hager testified that the results of the 2010 IRP suggest that a combination of additional baseload, intermediate, and peaking generation, as well as renewable, EE, and DSM resources, are needed to meet customers' needs over the next 20 years. She stated that the 2010 IRP supports new nuclear generation, either owned solely by Duke or jointly owned, as the best option for meeting Duke's long term baseload generation needs. She stated that the need for new baseload generation is demonstrated by the fact that, in the IRP, the cost to customers of portfolios including nuclear capacity and energy is lower than the cost of those portfolios that do not. Ms. Hager stated that this result was consistent with results obtained in IRP analyses performed in the 2007-2009 time frame. Therefore, testified Ms. Hager, it is prudent for Duke to continue to develop new nuclear generation as a resource option for the 2020 time frame.

In response to cross-examination, Ms. Hager agreed that the longer the period for which the Commission is asked to approve the decision to incur development costs, the more difficult it is for th8e Commission to decide whether that decision is reasonable and prudent. However, Ms. Hager also testified that even with Commission approval of the decision to incur development costs over a future period of time, the Company still has the responsibility during that period to monitor whether continuing with the development of the plant is in the customers' best interests. She also agreed that, in Duke's IRP analysis, after selecting portfolios to test against sensitive input assumptions, in two out of four cases the portfolio that delayed nuclear until the 2026-2028 time frame proved more cost-effective than the portfolio that installed nuclear capacity for the 2021 time frame and that two were lower with their being so close that she would call them a wash because they are so close in results. She also testified in response to questions from the Commission that there was really no difference in the present value of revenue requirements impact between completing the nuclear plant in the 2021-2023 time frame or in the 2026 time frame; however, she stated that one of the factors that persuaded the Company that the earlier date was preferable was the risk of high inflation if the plant was delayed.

The Groups witness Bradford recommended that the Commission not grant the application for approval of the decision to incur an additional $287 million in nuclear generation project development costs between the date of the filing and the end of 2013. Mr. Bradford stated that the fundamental reasons Duke had put forth as justification for the Lee project had been substantially undermined by events of the last three years. Mr. Bradford claimed that the need for new capacity had decreased from 7000 MW by 2018 in the 2008 proceeding to 2200 MW by 2020 and 6000 MW by 2030 in the currently filed proceeding. Mr. Bradford pointed out that the projected in-service date for the project had slipped by three years from 2018 as projected in the 2008 proceeding to 2021 in the current proceeding. Mr. Bradford also pointed out that projected natural gas prices are significantly lower than was the case in 2008 with the current Energy Information Administration's (EIA) projections of natural gas wellhead prices remaining under $5 through 2022. Mr. Bradford argued that this forecast made fuel diversity justifications unpersuasive when used to justify nuclear construction. Mr. Bradford stated that with Duke's current energy mix at less than 10% natural gas, diversity concerns point toward increasing the gas share.

Mr. Bradford also stated that the nuclear renaissance reported in the 2008 proceeding has collapsed due to declining demand, rising cost estimates, reduced cost estimates for alternatives, the absence of federal policies for reduced greenhouse gas emission, and lack of federal subsidy for new reactors. Mr. Bradford also provided some instances of cancellations of proposed facilities and solicitations of utilities seeking partners for the building of units. He further opined that any additional expenditures exposed ratepayers to further risk of loss and that, at this point, there is little chance that the Lee project could produce competitively priced electricity, even with a federal loan guarantee, which it has no immediate prospect of receiving.

Mr. Bradford also reiterated some recommendations to the Commission from his 2008 testimony to include: cap any prudence determination that it makes at a figure that does no more than maintain the current state and value of the Lee project; determine a maximum acceptable cost for the Lee project as a factor to mitigate cost overruns; revisit the determination that payments to secure long lead time items are "project development costs"; require competitive power procurement to screen supply resources; reiterate the 2008 statement that a showing will be required that all cost-effective EE programs are in place; and reduce the allowed rate of return allowed to investors if risk is shifted from investors to the rate payers.

The Public Staff presented, as a panel, witnesses Maness and Ellis, who testified that through December 31, 2009, Duke had incurred project development costs of approximately $172 million. The Public Staff witnesses testified that Duke is now asking for Commission approval of its decision to incur the project development costs necessary to continue development work from January 1, 2010, through December 31, 2013, of up to $287 million, for a total of $459 million through December 31, 2013, to ensure that the Lee Nuclear Station remains an option to serve customer needs in the 2021 timeframe.

With regard to Duke's previous applications for approval to incur nuclear development costs, witnesses Maness and Ellis testified that, by Order issued March 20, 2007, prior to the enactment of G.S. 62-110.7, the Commission ruled 1) it was appropriate in general for Duke to pursue preliminary siting, design and licensing of the proposed Lee Nuclear Station through December 31, 2007, and to incur costs not to exceed the North Carolina allocable portion of Duke's total system share of $125 million, and 2) it was in the public interest for all potential resource options, including nuclear generation, to be adequately considered to ensure that the most economical resources are available to meet customers' needs on a timely basis. By Order issued August 6, 2007, the Commission clarified that it did not intend to approve or endorse any specific nuclear technology or design, and that it had not pre-approved or denied any particular ratemaking treatment for development costs regardless of whether the plant was completed, abandoned, or never begun.

According to witnesses Maness and Ellis, on December 7, 2007, Duke filed an application pursuant to the newly enacted G.S. 62-110.7 requesting approval to incur up to $160 million in project development costs, for the January 1, 2008, through December 31, 2009, time period, to ensure that the Lee Nuclear Station remained an option to serve customer needs in the 2018 timeframe. On June 11, 2008, the Commission issued an Order approving Duke's decision, subject to a limit on such costs to the North Carolina allocable portion of a total system amount of $160 million and a limit on the time that such costs could be incurred to the period from January 1, 2008, to December 31, 2009. Witnesses Maness and Ellis testified that, in its Order, the Commission stated that its approval did not constitute approval of any particular activities or costs, all of which would be subject to later determinations as to their prudence and reasonableness, placed Duke on notice that the approval in the Order could not be interpreted as making it probable that the recovery of any specific actual costs would be allowed, and required Duke to file for approval for the use of a regulatory asset account with respect to any abandoned project development costs.

Witnesses Maness and Ellis further explained that the utility's initial decision to incur some level of project development costs is typically made before these costs are actually incurred. The decisions to undertake individual specific activities or to make specific expenditures are made after the initial decision or decisions and are based upon a number of factors. Furthermore, changes in facts and circumstances occurring after the initial decision to proceed and subsequent decisions to continue with project development may affect not only the appropriate timing of a specific activity or expenditure, but also may raise questions as to the reasonableness and prudence of going forward with certain specific activities and expenditures at all. It is these types of factors and changes in circumstances that arise during the course of project development that the utility must consider before it takes further action and that the Commission must consider in determining whether an actual activity or expenditure is reasonable and prudent.

Based on their review of the Company's application and its current IRP, witnesses Maness and Ellis testified that Duke's general decision to incur additional project development costs is reasonable and prudent so that the proposed Lee Station can be maintained as a potential resource option to satisfy future projected load and energy requirements. They further stated, however, that the Public Staff has a number of concerns about Duke's application, particularly the amount that has been requested and the time period included in the request.

The Public Staff witnesses stated that the Public Staff's first concern relates to the uncertainty that has been evident in recent years regarding Duke's need for a nuclear unit to be on line by any certain date in the future. When the Company filed its first request related to nuclear development costs in 2006, it stated that it needed 1,734 MW of nuclear baseload generation to serve its expected 2016 load. When the Company filed its next project development cost application in late 2007, it had reduced the initial need to one 1,117 MW unit and delayed it until 2018. At that time, the Company anticipated filing for a certificate with the SCPSC in late 2008. The current filing states that the first nuclear unit will be needed in 2021 and indicates that Duke anticipates filing its application for a certificate with the SCPSC closer in time to the receipt of the COL, which is expected in 2013.

The Public Staff witnesses also testified that an interrelated concern is the fact that it has been a number of years since Duke conducted a comprehensive study to justify its 17% target planning reserve margin. As a result, the Public Staff recommended that the Company be required to conduct a comprehensive reserve margin study to determine the optimal level of reserves to provide generation reliability while minimizing the cost to ratepayers, and file it next year with its IRP filing.

With respect to the Public Staff's third concern, witnesses Maness and Ellis testified that the Public Staff is concerned, as discussed in its 2010 IRP Comments, about the lack of a no- or low-carbon regulation scenario in Duke's IRP evaluations. In its application in the 2008 proceeding in this docket, the Company stated that its 2007 IRP analysis showed that the optimal resource mix varies under different scenarios, with an assumption of no carbon regulation making portfolios that do not contain new nuclear look best, and an assumption of high CO_2 allowance prices making a portfolio with two nuclear units look most cost-beneficial. In its reference case in the current IRP proceeding, Duke assumed a cap and trade program with CO_2 prices based on the Waxman/Markey legislation delayed until 2015. Under that scenario, two nuclear units in 2021 and 2023 were $1.8 billion more cost-effective than the natural gas-fired CT/CC portfolio. Through discovery, however, the Public Staff learned that under a no-carbon regulation scenario, the CT/CC portfolio was more advantageous, relative to the two nuclear unit portfolio, than it was in the reference case.

Witnesses Maness and Ellis further testified that the Public Staff's fourth concern is the seemingly slow pace of the development of sharing the risks, rate impacts, and lumpiness associated with new nuclear plants. In discovery, the Public Staff asked Duke for the details of its efforts to join South Carolina Electric & Gas Company (SCE&G) and Santee Cooper in the new nuclear units planned for their existing V.C. Summer Station, particularly with regard to Santee Cooper's stated intent to sell off a significant part of its current ownership interests in the new units. Duke responded that it had been in communication with Santee Cooper and that it continues to explore approaches that could lead to sharing a portion of Santee Cooper's ownership. Witnesses Maness and Ellis testified that Duke recently entered into an option agreement with JEA pursuant to which JEA has the option to purchase an undivided ownership of not less than five percent and not more than 20 percent of the proposed Lee Station. The Public Staff witnesses stated that, given the very high capital costs associated with the construction of a nuclear plant, the fact that the addition of the Lee Station as proposed by Duke will create lumpiness and projected higher than optimal reserve margins early in the plant's operational life, and the uncertainty as to the timing of Duke's actual need for baseload capacity, among other things, the Public Staff believes that every effort should be made to explore sharing these risks and costs with other entities.

Witnesses Maness and Ellis pointed out that Duke incurred approximately $36 million in project development costs related to the Lee Station between January 1, 2010, and December 31, 2010, including AFUDC, that the Company proposes to incur approximately $250 million from January 1, 2011, through December 31, 2013 (also including AFUDC), and that the Company seeks approval of its decision to incur the total amount of project development costs incurred or to be incurred for the four-year period from January 1, 2010, through December 31, 2013, for a total of $459 million since its initial decision. Duke's testimony, however, focuses on the IRP it filed in September of 2010 as justification for its decision to continue to incur nuclear project development costs, with only a general mention that the earlier IRPs support such a decision. The witnesses testified that the Public Staff has focused its recommendation on the prospective period, but, based upon its review of the 2008 and 2009 IRP proceedings (Docket No. E-100, Subs 118 and 124, respectively), the Public Staff believes that Duke's decision to continue to incur project development costs as of January 1, 2010, was not unreasonable. However, the Public Staff believes that it would be highly beneficial to the Commission for a utility to make its filings pursuant to G.S. 62-110.7 prior to the time period for which it plans to begin or continue incurring costs pursuant to that decision. They testified that the Public Staff would strongly encourage Duke to file its requests prospectively in the future, as it did the first two times it filed in this docket. In any event, because the utility filing an application pursuant to G.S. 62-110.7 has the burden of demonstrating by a preponderance of the evidence that its decision to incur project development costs is reasonable and prudent, all of the justification for the entire time period in question should be included in the application and supporting pre-filed testimony.

Based upon all of the foregoing concerns, the Public Staff witnesses testified that the Commission should limit its approval of Duke's decision to incur additional project development costs to a lower dollar amount and a shorter time period than requested in Duke's application. Specifically, the Public Staff recommended that the time period be limited to January 1, 2011, through June 30, 2012, and correspondingly the dollar amount be limited to a maximum of the North Carolina allocable share of $120 million, including any AFUDC accrued during the approved 2011/2012 time frame on the costs incurred both before and on or after January 1, 2011. The witnesses pointed out that this recommended amount is slightly greater than the amount the Company estimates it will spend during the 18-month period in question.

Witnesses Maness and Ellis indicated that these limitations are reasonable, given the current uncertainty with respect to potential carbon legislation, the need for Duke to conduct a comprehensive reserve margin study, the potential for further delay in the need for nuclear generation, the high costs associated with nuclear construction, and the need for in-depth exploration of sharing the costs and risks of nuclear construction, whether with respect to the SCE&G/Santee Cooper V.C. Summer Station or otherwise. These limitations also will provide the Commission the opportunity to receive additional information as a result of the 2011 IRP proceeding, and another opportunity to consider these issues before approving the decision to incur additional project development costs.

With respect to the $36 million Duke incurred during 2010, witnesses Maness and Ellis stated that the Public Staff did not contest Duke's general decision to continue to incur additional project development costs, but that the Commission should not include in its approval a specific amount of dollars that Duke already has spent. It is more appropriate for the Commission to impose a not-to-exceed cap for prospective expenditures, as it did in the previous orders in this docket.

In addition to the foregoing, witnesses Maness and Ellis stated that any Commission Order approving Duke's decision to incur additional project development costs related to the Lee Station should again state that the Order does not constitute approval to spend any specific amount, nor to engage in any specific activities. It also should state that it does not constitute a finding that additional base load capacity is needed within the relevant time frame nor a finding that the Lee Station should be built. They further testified that any Commission Order approving Duke's decision to incur additional project development costs related to the Lee Station should again state that, although it is appropriate for Duke to continue to accrue AFUDC on the Lee Station project development costs, such AFUDC accrual is provisional, subject to future determinations by the Commission as to the reasonableness and prudence of all project development costs associated with the Lee Station, including AFUDC. Also, they recommended that the appropriateness of the accounting treatment employed by the Company relative to such AFUDC be subject to future Commission determination.

The Public Staff witnesses recommended that Duke should be required to file reports similar to the reports required by the Commission in prior orders in this docket. Specifically, Duke should be required to file the following: (1) on August 1, 2011, a report detailing its activities and expenditures in pursuit of project development for the Lee Station from January 1, 2011, through June 30, 2011; (2) on February 1, 2012, a report detailing its activities and expenditures in pursuit of project development for the Lee Station from July 1, 2011, through December 31, 2011; and (3) on August 1, 2012, a report detailing its activities and expenditures in pursuit of project development for the Lee Nuclear Station from January 1, 2012, through June 30, 2012. Any Commission order approving Duke's decision to incur project development costs should provide that these reports are for informational purposes only and that they cannot be used as support for an argument that the Commission has made any determination with respect to the reasonableness or prudence of the activities and expenditures reported therein.

Finally, witnesses Maness and Ellis recommended that any approval granted by the Commission in this proceeding should again state that such approval is not to be considered approval to record any abandoned project development costs in a regulatory asset account. The requirement of Commission Rule R8-27 for the Company to apply to the Commission for use of regulatory asset accounts should continue to apply in this case, because (1) any approval granted in this proceeding should not be understood as making it probable at this time that the recovery of any specific actual costs will be allowed, and (2) it would be appropriate and beneficial for the Commission to begin to examine the circumstances of any abandonment as close as possible in time to abandonment, and such examination would be facilitated by the continued requirement that a request for regulatory asset approval be filed with the Commission.

In response to questions on cross-examination, Public Staff witness Maness testified that, if after Duke incurs the development costs for the Lee Station, JEA exercises its option to purchase capacity in the Station, it would be reasonable to expect that any costs related to the Station that have already been recovered from North Carolina retail customers at that point in time (e.g., amounts resulting from CWIP having been previously included in rate base or amounts already recovered due to the legislation being considered) would be ultimately treated so that, to the extent a joint owner gets a benefit from the plant, the costs that are proportionately associated with that benefit should not be expected to be borne by North Carolina retail ratepayers. Mr. Maness also testified on cross-examination that Commission approval of Duke's request would not ensure that Duke will recover the costs that it incurs from now until 2013. For example, if it became evident six months into the future that the Station clearly was no longer in the interest of the ratepayers, Duke would be under an obligation to make the prudent decision that the plant should be cancelled. In effect, Duke is obligated to continue to examine, on a continuous basis, the decisions to proceed with development.

In response to questions by the Commission regarding the advisability of continuing to incur costs for the Lee Station in light of the nuclear plant failures in Japan resulting from the earthquake and tsunami, Public Staff witness Ellis testified that he did not have reservations at that time about continuing to proceed. He stated that, while it might introduce additional costs, the ultimate goal of the NRC would be to implement any necessary changes in design to ensure public safety.

In its proposed order, the Public Staff amended its position and stated that, in light of Duke's position that it will not proceed with construction absent legislation allowing recovery of CWIP financing costs outside a general rate case, and the fact that no such legislation is now pending before the General Assembly, it is not appropriate to approve Duke's application at this time. Instead, the approval granted by this order should be limited to Duke's decision to incur only those nuclear project development costs that must be incurred to maintain the status quo with respect to the Lee Station, including Duke's COL application at the NRC. Accordingly, the Public Staff recommended that, while the Commission cannot find that such costs should be incurred during a certain period of time, it should order that the costs be subject to a not-to-exceed cap of the North Carolina allocable portion of $120 million.

In rebuttal of the testimony of the Groups witness Peter Bradford, Duke witness Rogers testified that although the recent economic downturn has caused a short-term reduction in the demand for electricity and the anticipation of abundant shale natural gas has depressed forward prices for natural gas, thus causing several nuclear construction projects, including the Lee Station, to be delayed, these developments have not eliminated the need for new nuclear capacity. He asserted that nuclear generation remains the appropriate choice for Duke's customers, as demonstrated by Duke's 2010 IRP. The differences between Duke's changes in its development and construction timeline and those of certain other project developers can often be accounted for by factors relating to the different forms of market regulation (including deregulated markets) and technologies associated with each individual project. Duke, like other utilities in regulated markets, continues to be subject to an obligation to plan for and serve retail customers over the long term, and employs detailed IRP processes to evaluate resource options. With regard to technology, Mr. Rogers opined that Duke's chosen reactor design (Shaw Nuclear and Westinghouse Electric Company's AP1000) would enable Duke to follow the progress of and learn lessons from AP1000 projects that are further along than the Lee Station in development and construction.

In rebuttal to Mr. Bradford's assertion that approval of Duke's request in this proceeding would expose the Company's customers to costs and harm, Duke witness Rogers testified that such is not the case. He stated that Duke has taken a "measured and deliberate" approach to the development of the project. Additionally, Mr. Rogers stated that the warnings of Mr. Bradford against shifting the risk of loss and charging large costs to captive customers, and his recommendation that caps be placed on the overall cost of the Lee Station, reflect a misunderstanding of this proceeding, which is limited to approval of a decision to continue to incur project development costs, and is not a proceeding to determine whether the Lee Station should receive a certificate of public convenience and necessity. Mr. Rogers also testified that the risks of successfully developing, designing, and constructing the Lee Station would not be mitigated by the Commission's approval of Duke's request in this proceeding, and thus would not make it appropriate for the Commission to reduce the Company's allowed return on common equity in a future general rate case.

In further rebuttal of the Groups witness Bradford, Duke witness Hager testified that Mr. Bradford's claim that the need for power has dropped dramatically since the 2008 development costs proceeding is incorrect. She stated that Mr. Bradford did not account for the fact that the need for new capacity set forth in the 2008 proceeding included amounts of capacity that are not shown as needed in the current proceeding, due to the fact that they are assumed to be fulfilled by the Cliffside Unit 6 coal facility and the Buck and Dan River combined cycle plants. With respect to Mr. Bradford's testimony that current projections of natural gas and carbon allowance prices are lower than they were in the previous IRP proceeding, Ms. Hager stated that the current prices are remarkably similar to the prices used in the 2007 IRP. However, she testified that these older projections are not important; instead, she stated, that what is important are the results of the most recent analyses, which show that even with the relatively low projections of natural gas prices, the portfolio with new nuclear generation is projected to be cost effective. Additionally, with regard to natural gas volatility, she testified that doubling the cost of natural gas would increase the fuel cost disadvantage of the no-nuclear portfolio over the two nuclear unit portfolio by 17 percentage points (from 27% to 44%); while doubling the cost of nuclear fuel would only reduce that disadvantage by eight percentage points (to 19%). She stated that this does not mean that the Company is anti-natural gas, however, pointing out that the two nuclear unit portfolio still includes over 3,000 MW of new natural gas capacity.

With respect to Mr. Bradford's use of busbar costs to illustrate the cost disadvantage of nuclear power to natural gas-fired power, Duke witness Hager testified that levelized busbar costs are meaningless in resource planning. She stated that sophisticated models are needed to develop the most cost-effective portfolio of resources. With respect to Mr. Bradford's criticism of the Company for not conducting a competitive solicitation, she testified that the Company's purchased power philosophy does not currently incorporate the bidding out of baseload capacity. According to Ms. Hager, the susceptibility of generation outside of the utility's control area to interruption and the risk of supplier default are the two key factors militating against the use of purchased power to provide baseload needs.

In rebuttal to Mr. Bradford's contention that nuclear power is not an effective strategy for fighting climate change, Duke witness Hager testified that without the addition of nuclear generation, carbon emissions in 2030 will be substantially higher than in 2010, even with aggressive EE efforts and compliance with the North Carolina REPS. With respect to Mr. Bradford's assertion that new nuclear generation will cause a decrease in jobs due to higher electric prices, she testified that the goal of Duke's IRP is to minimize rate impacts on customers; the Company's analyses demonstrate that it is in the customers' best interests for Duke to continue to pursue the development of the Lee Nuclear Station.

With respect to the Public Staff's testimony concerning the asserted slow pace of the pursuit of nuclear development partners, Duke witness Rogers testified that the development of partnerships in projects do not follow a predefined schedule. He further stated that with approximately ten years remaining before the commercial operation date for the Lee Nuclear Station, there was ample time to include additional partners in the project. He testified that Duke was committed to finding partners, and also continues to explore the possibility of beneficial participation in other regional nuclear generation projects, including the new V.C. Summer units currently owned by Santee Cooper, with which the Company is continuing discussions. In response to a question from the Commission, Mr. Rogers stated that Duke has a team that has been working on the issue of finding partners for regional construction for 18 months, but it has not historically been part of the culture of the electric industry to engage in joint partnerships. Mr. Rogers stated that partnerships could take the form of joint ownership arrangements or purchased power arrangements. Mr. Rogers also testified that if the types of partnerships he describes do not take place, another way to spread the costs of nuclear over a larger customer base would be through the planned merger with Progress Energy.

In rebuttal of the testimony of the Public Staff witnesses regarding the Public Staff's concerns about the Company's 17% reserve margin, Company witness Hager testified that the

Company has used this reserve margin for over 10 years, and noted that it was approved by the Commission in Docket No. E-100, Subs 118 and 124. Ms. Hager noted that in the currently pending IRP proceeding, Docket No. E-100, Sub 128, the Public Staff has recommended that the Company be required to conduct a reserve margin study, a recommendation that the Company has noted it does not believe is appropriate at this time. The Company has also requested that if the Commission does require it to perform a reserve margin study, it be allowed to consider the impact of the proposed merger between itself and Progress Energy. Ms. Hager testified that at present, the Company "remains confident" that the 17% reserve margin is reasonable and appropriate. However, she testified, a change in the reserve margin would have little impact on the need for the Lee Nuclear Station, because a change in the reserve margin would likely affect the need for peaking capacity, not baseload capacity.

With respect to the Public Staff's concern that Duke has not provided a no- or low-carbon regulation scenario in its IRP, Company witness Hager testified that Duke provided three scenarios – a base carbon case, a high carbon sensitivity, and a Clean Energy Standard sensitivity. She stated that the Company did not perform a no-carbon sensitivity for the 2010 IRP because of its belief that it is a matter of how and when, not if, carbon emissions will be regulated. Ms. Hager also testified that due to the Public Staff's expressed concern, the Company had recently performed a no-carbon sensitivity on its base case portfolio. Under this scenario, a portfolio made up of combustion turbine and combined cycle facilities was more cost-effective than a portfolio containing two nuclear units. However, Ms. Hager stated, it is important to note that if we were truly in a no carbon future, new coal generation may be cost-effective and would likely replace the natural gas combined cycles.

Further in rebuttal to the Public Staff, Ms. Hager testified that the Public Staff's conclusion that a mid-carbon, low fuel cost scenario would substantially delay the need for new nuclear capacity was incorrect. She stated that although a delayed nuclear scenario was among those selected as representing the reasonable range of potential portfolios that could be beneficial to customers under a wide variety of potential future outcomes, Duke's analysis did not lead to a conclusion that delay was in the best interests of the Company's customers.

Duke witness Jamil, in rebuttal to the Public Staff, testified that to limit the time period of project development activities to January 1, 2011, through June 30, 2012, or change the limit of the dollar amount spent on such activities to the North Carolina allocable share of $120 million is unwarranted and may unduly hamper the Company's efforts to preserve the nuclear option for its customers in the 2021 time frame. Mr. Jamil also disagreed with the Public Staff in regard to its position taken regarding expenditures for project development made during the 2010 time frame. The Public Staff stated that it does not consider the decision to continue to incur project development costs to be unreasonable, but the Commission should not include in its decision a specific amount of dollars already spent. Mr. Jamil stated that the project development work through 2013 is necessary to ensure the Company can obtain a COL in 2013 and continue to preserve the option to have Lee Nuclear Station available to serve customers in the 2021 time frame.

Mr. Jamil further stated that the Public Staff based its position on the following: the current uncertainty with respect to carbon legislation, the need for Duke to conduct a comprehensive Reserve Margin Study, the potential for further delay in the need for nuclear generation, the high costs associated with nuclear generation, and the need for in-depth exploration of sharing the costs and risks of nuclear construction, whether with respect to SCE&G/Santee Cooper V.C. Summer Station or otherwise. Mr. Jamil stated that Duke witnesses Rogers and Hager addressed aspects of the Public Staff's concern and noted that many of these uncertainties had existed for some time and may continue to exist beyond June 30, 2012. Mr. Jamil stated that this date does not correspond to the COL or the project development schedule, appears arbitrary, and would result in Duke having to file another application this year in order to incur the additional costs to be incurred through the projected receipt of the COL. Mr. Jamil stated that Duke has every incentive to cease its project development efforts if it determines that such development is no longer in the best interest of its customers.

Mr. Jamil also stated that in Docket No. E-100, Subs 118 and 124, the Commission approved the Company's plan that selected new nuclear generation as the appropriate resource to meet Duke's needs in the future. The Company's decision to incur development costs during 2010 was consistent with the results of its planning analysis, which have been deemed to be reasonable by both the Public Staff and the Commission for planning purposes. Mr. Jamil stated that he believes the Commission should find that the Company's decision to continue to incur development costs in 2010 was reasonable and prudent under the circumstances, and such costs should be included in any order approving the Company's decision to incur project development costs.

Based upon the foregoing, the Commission concludes that, in light of Duke's position that it will not proceed with construction absent legislation allowing recovery of CWIP financing costs outside a general rate case, and the fact that no such legislation is now pending before the General Assembly, it is not appropriate to approve Duke's application at this time. Instead, the approval granted by this order should be limited to Duke's decision to incur only those nuclear project development costs that must be incurred to maintain the status quo with respect to the Lee Nuclear Station, including Duke's COL application at the NRC. Accordingly, while the Commission cannot find that such costs should be incurred during a certain period of time, it will order that the costs incurred on or after January 1, 2011, be subject to a not-to-exceed cap of the North Carolina allocable portion of $120 million.

While uncertainties are not new to the electric industry, very significant uncertainties have been added since the last proceeding. These include whether North Carolina will enact legislation that will allow Duke's rates to "track" CWIP in a manner similar to legislation that has already been passed in South Carolina; the amount of load lost due to the recession that will not return and the extent to which growth in customer demand will occur as the economy improves; and the effect of the nuclear plant failures in Japan resulting from the earthquake and tsunami on March 11, 2011, on the timing and the construction costs of future nuclear plants and the costs related to spent nuclear fuel storage.

Of particular importance is the uncertainty as to the date in the future when Duke would need a nuclear unit to be on line. Duke's projected need in its 2006 filing in this docket for nuclear baseload generation was 1,734 MW by 2016. In its late 2007 filing, Duke had reduced the initial need to one 1,117 MW unit and delayed it until 2018. At that time, the Company anticipated filing for a certificate with the SCPSC in late 2008. Duke's projected need for the first unit has now been moved out to 2021, and the certificate application filing with the SCPSC is not expected until 2013.

In addition to the foregoing, it is even less clear than in the last proceeding as to the likelihood that carbon regulation will occur in the not too distant future, much less when and at what costs. At the time Duke performed and filed its IRP, the expectation was that carbon legislation would be passed within the foreseeable future, and there were several proposals and prices to use as assumptions. Since then, however, the make-up of the Congress has changed significantly and assumptions are much more speculative. Because carbon regulation has a significant effect on whether and when new nuclear units become part of the optimal resource mix under Duke's planning process, there is less support for Duke's assumptions as to when nuclear units will prove to be the most cost effective resource option. In this regard, Duke witness Hager's testimony on cross-examination that, in Duke's IRP analysis, after the selection of portfolios to test against sensitivities, the analysis showed that there is no difference in the present value of revenue requirements impact between completing the nuclear plant in the 2021-2023 time frame or in the 2026 time frame, buttresses this conclusion.

In addition, it is not appropriate in this proceeding, as requested in Duke's application, to approve a total cumulative amount of nuclear project development costs. While Duke modified its request by the filing of a notice of acceptance on May 3, 2011, stating that its proposed order will adopt the Public Staff's pre-filed position that the Company's decision to incur additional project development costs of up to $120 million from January 1, 2011, through June 30, 2012, for the proposed Lee Station is reasonable and prudent, Duke misstated the Public Staff's position. The Public Staff's pre-filed position was that the $120 million would be a not-to-exceed cap on expenditures. No specific costs or activities have ever been approved in these proceedings, and all activities and expenditures will be subject to later determinations as to their reasonableness and prudence.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The evidence for this finding of fact is found in the testimony of Public Staff witnesses Maness and Ellis.

The Public Staff witnesses testified that if Duke decides to cancel the Lee Nuclear Station prior to the issuance of a certificate, any approval granted by the Commission in this proceeding should not be considered approval to record any abandoned project development costs in a regulatory asset account. They asserted that any such treatment requires that Duke file an application with the Commission. The requirement of Commission Rule R8-27 for the Company to apply to the Commission for use of regulatory asset accounts should continue to apply in this case, because (1) any approval granted in this proceeding should not be understood as making it probable at this time that the recovery of any specific actual costs will be allowed, and (2) it would be appropriate and beneficial for the Commission to begin to examine the circumstances of any abandonment as closely as possible in time to that abandonment, which examination would be facilitated by a requirement that a request for regulatory asset approval be filed.

No party opposed the Public Staff's recommendation that any Commission order issued in this proceeding (1) include a statement that the Commission's approval of Duke's application in this docket was not to be interpreted as making it probable at this time that the recovery of any specific actual costs would be allowed and (2) state that Duke is required to file an application with the Commission in order to use a regulatory asset account for any abandoned project development costs. The Commission concludes that this recommendation should be adopted. The approval herein of Duke's decision to incur project development costs is not to be interpreted as making it probable at this time that the recovery of any specific actual costs will be allowed, and, further, Duke is required to file an application with the Commission in order to use a regulatory asset account for any abandoned project development costs.

IT IS, THEREFORE, ORDERED as follows:

1. That, in light of Duke's position that it will not proceed with construction absent legislation allowing recovery of CWIP financing costs outside a general rate case, and the fact that no such legislation is now pending before the General Assembly, it is not appropriate to approve Duke's application at this time. Instead, the approval granted by this Order is limited to Duke's decision to incur only those nuclear project development costs that must be incurred to maintain the status quo with respect to the Lee Station, including Duke's COL application at the NRC.

2. That nuclear project developments costs incurred on or after January 1, 2011, shall be subject to a not-to-exceed cap of the North Carolina allocable portion of $120 million.

3. That the approval of a not-to-exceed cap of $120 million is not approval to spend up to the North Carolina allocable portion of that amount. No specific activities or costs are being approved, and all activities and expenditures will be subject to later determinations as to their prudence and reasonableness.

4. That Duke shall file a report on September 1, 2011, detailing its activities and expenditures in pursuit of project development for the Lee Station from January 1, 2011, through June 30, 2011; and that Duke shall file further reports every six months, beginning February 1, 2012, until further order of the Commission, detailing its activities and expenditures in pursuit of project development for the Lee Station during the six-month period ending one month before the due date for the report (e.g., the report due February 1, 2012, would cover the period from July 1, 2011, through December 31, 2011).

5. That the reports ordered herein shall be used for informational purposes only and cannot be used as support for an argument that the Commission has made any determination with respect to the reasonableness or prudence of the activities and expenditures reported therein.

6. That Duke is on notice that the Commission's limited approval in this proceeding of Duke's decision to incur project development costs cannot be interpreted as making it probable at this time that the recovery of any specific actual costs will be allowed and that Duke is required to file an application with the Commission prior to the use of a regulatory asset account with respect to any abandoned project development costs.

ISSUED BY ORDER OF THE COMMISSION.
This the 5th day of August, 2011.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

kh080511.01

ELECTRIC – MISCELLANEOUS

DOCKET NO. E-7, SUB 984

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 8-67	)	ORDER APPROVING REPS AND REPS EMF RIDERS AND 2010 REPS COMPLIANCE

HEARD: Wednesday, June 8, 2011, 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 Lorinzo L. Joyner, William T. Culpepper, III, ToNola D. Brown-Bland, and Lucy T. Allen

APPEARANCES:

For Duke Energy Carolinas, LLC:

Charles A. Castle, Senior Counsel, Duke Energy Corporation, 550 South Tryon Street, Charlotte, North Carolina 28201

Robert W. Kaylor, Law Office of Robert W. Kaylor, P.A., 3700 Glenwood Avenue, Suite 330, Raleigh, North Carolina 27612

For North Carolina Sustainable Energy Association:

Kurt Olson, North Carolina Sustainable Energy Association, 1111 Haynes Street, Suite 109, Post Office Box 6465, Raleigh, North Carolina 27628

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

BY THE COMMISSION: On March 11, 2011, Duke Energy Carolinas, LLC (Duke or the Company), filed its Application for Approval of REPS Cost Recovery seeking an adjustment to its North Carolina 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 to determine whether a rider should be established to permit the recovery of the incremental costs incurred in order 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 over- or under-recovery of compliance costs. Duke's Application was accompanied by the pre-filed testimony and exhibits of Kim H. Smith, Rates Manager for Duke, and Emily O. Felt, Director of Renewable Strategy and Compliance, Carolinas, for Duke Energy Corporation. In its Application and pre-filed testimony, Duke sought approval of a proposed REPS rider, which incorporates the Company's proposed adjustments to its North Carolina retail rates. One of the exhibits attached to witness Felt's testimony was Duke's 2010 REPS compliance report, which is required to be filed annually under Rule R8-67(c).

On March 15, 2011, the Commission issued an Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice, in which it set this matter for hearing; established deadlines for the submission of intervention petitions, intervenor testimony, and Duke's rebuttal testimony; required the provision of appropriate public notice; and mandated compliance with certain discovery guidelines.

Petitions to intervene were filed by Carolina Industrial Group for Fair Utility Rates III (CIGFUR); GreenCo Solutions, Inc. (GreenCo); Carolina Utility Customers Association, Inc. (CUCA); North Carolina Sustainable Energy Association (NCSEA); and Blue Ridge Electric Membership Corporation (Blue Ridge EMC). Each of these petitions to intervene was allowed by the Commission. The intervention and participation of the Public Staff are recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

On May 13, 2011, Duke filed affidavits of public notice indicating that public notice had been provided in accordance with the Commission's procedural order.

On May 18, 2011, the Public Staff filed the testimony and exhibits of Randy T. Edwards, Staff Accountant, and the testimony of Jay B. Lucas, Utilities Engineer; and NCSEA filed the testimony of its Executive Director, Ivan K. Urlaub. On June 2, 2011, Duke filed the rebuttal testimony and exhibits of witness Smith and the rebuttal testimony of witness Felt. On June 6, 2011, the Public Staff filed the revised testimony and exhibits of witness Edwards and the revised testimony of witness Lucas.

On June 6, 2011, the Commission issued an order authorizing Duke witnesses Smith and Felt to appear as a panel and continuing the evidentiary hearing until June 8, 2011. The public hearing was held as scheduled on June 7, 2011, and no public witnesses appeared. At the evidentiary hearing on June 8, the Commission granted an oral motion of the Public Staff that its witnesses be allowed to appear as a panel. Duke presented the testimony and exhibits of witnesses Smith and Felt; the Public Staff presented the testimony and exhibits of witness Edwards and the testimony of witness Lucas; and NCSEA presented the testimony of witness Urlaub.

Based upon the foregoing, the testimony and exhibits introduced at the hearing, Duke'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

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FINDINGS OF FACT

1. Duke 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. Duke is engaged in the business of generating, transmitting, distributing and selling electric power to the public in North Carolina. Duke is also an electric power supplier as defined in G.S. 62-133.8(a)(3). Duke 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 Renewable Energy and Energy Efficiency Portfolio Standard (REPS) established by G.S. 62-133.8, beginning in the year 2010, electric power suppliers must supply at least 0.02% of their previous year's North Carolina retail energy sales by a combination of new solar electric facilities and new metered solar thermal energy facilities. In 2012, this solar requirement increases to 0.07% of the previous year's North Carolina retail sales. Also in 2012, electric power suppliers must generally meet 3% 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. The electric power suppliers of North Carolina are 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.

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 amount of 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.

5. Duke 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 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. Duke and the seven electric power suppliers to which Duke is providing compliance services met their 2010 REPS obligations. Duke's 2010 REPS compliance report should be approved.

7. For purposes of Duke'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 2010, and the 12-month period ending August 31, 2012.

8. In Docket No. E-7, Sub 856, the Commission concluded that it is appropriate for Duke, as one component of its effort to comply with the solar requirements of the REPS, to install a limited amount of self-built solar distributed generation. It is not appropriate in this proceeding to address issues regarding the public convenience and necessity of future electric generating facilities.

9. Duke appropriately based the incremental costs of its Solar Distributed Generation (DG) program to be recovered by the REPS riders upon the levelized revenue requirements of the capital and operating costs over the expected lives of the solar facilities less the levelized avoided costs and limited by the effective price per MWh submitted by the third-place bidder in response to Duke's request for proposals (RFP).

10. For purposes of establishing the REPS EMF rider in this proceeding, Duke's incremental Solar DG program costs amount to $752,710.

11. Duke has appropriately made information available about the research and administrative costs it seeks to recover through the REPS rider, and it has not acted improperly in filing some information under seal.

12. The research activities funded by Duke during the test period and 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.

13. For purposes of establishing the REPS EMF rider in this proceeding, Duke's incremental costs for REPS compliance during the test period were $8,637,984, including the costs incurred for its wholesale customers, and these costs were reasonable and prudently incurred.

14. Duke's North Carolina test period REPS expense under-collection was $1,916,078, $1,258,995 and $461,049 for Duke's residential, general service and industrial customer classes, respectively, excluding gross receipts tax and regulatory fee.

15. Duke's North Carolina billing period expense for use in this proceeding is $7,133,159, 4,805,286 and $1,170,796 for Duke's residential, general service and industrial customer classes, respectively, excluding gross receipts tax and regulatory fee.

16. The appropriate monthly amount of the REPS EMF rider per customer account, excluding gross receipts tax and regulatory fee, to be collected during the billing period is $0.10 for residential accounts, $0.49 for general service accounts, and $7.37 for industrial accounts.

17. The appropriate monthly amount of the REPS rider per customer account, excluding gross receipts tax and regulatory fee, to be collected during the billing period is $0.37 for residential accounts, $1.87 for general service accounts, and $18.70 for industrial accounts.

18. The combined monthly REPS and REPS EMF rider charges per customer account, excluding gross receipts tax and regulatory fee, to be collected during the billing period are $0.47 for residential accounts, $2.36 for general service accounts, and $26.07 for industrial accounts.

19. Duke's REPS incremental cost rider to be charged to each customer account for the billing period is within the annual cost caps established in G.S. 62-133.8(h)(4).

20. It is appropriate for Duke and the Public Staff to jointly evaluate Duke's cost allocation between retail and wholesale customers for renewable energy certificates (RECs) derived from energy efficiency and electricity obtained from the Southeastern Power Administration (SEPA). If necessary, either party or both parties may propose a different allocation method than that used in the current proceeding.

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) establishes a REPS for all electric power suppliers in the State. The statute requires, for example, each electric public utility to provide a certain percentage of its North Carolina retail sales from various renewable energy or energy efficiency resources, including the following: (a) generating electric power at a new renewable energy facility; (b) using 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) reducing energy consumption through the implementation of energy efficiency measures; (d) purchasing electric power from a new renewable energy facility; (e) purchasing renewable energy certificates; or (f) using electric power that is supplied by a new renewable energy facility or saved due to the implementation of an energy efficiency measure that exceeds the requirements of the REPS for any calendar year as a credit towards the requirements of the REPS in the following calendar year. Each of these measures is subject to certain additional limitations and conditions. In 2012, Duke must generally meet 3% of its previous year's North Carolina retail electric sales by a combination of these measures.

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 0.02% for 2010-11 and 0.07% for 2012.

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. In 2012, the aggregate requirement for swine waste resources is 0.07%. 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 is 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, Duke's share of the aggregate State set-aside requirements for energy from swine and poultry waste is based on the ratio of its North Carolina retail kilowatt-hour sales for the previous year divided by the previous year's total North Carolina retail kilowatt-hour sales.

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 rider 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."

Duke's 2010 REPS compliance report states that, pursuant to G.S. 62-133.8(c)(2)(e), the Company provides 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. Available methods of REPS compliance for these municipal electric suppliers and EMCs are those set forth in G.S. 62-133.8(c).

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence supporting this finding of fact appears in Duke's 2010 REPS compliance report and in the testimony of Duke witness Felt and Public Staff witness Lucas. In addition, the Commission takes judicial notice of information contained in NC-RETS.

Duke's 2010 REPS compliance report was admitted into evidence as Exhibit 1 to the testimony of Duke witness Felt. Witness Felt testified that the report provides the information required by Commission Rule R8-67(c) in aggregate for Duke and the wholesale customers for which Duke has agreed to provide REPS compliance services. Public Staff witness Lucas testified that he had reviewed the compliance report and that it meets the requirements of Commission Rule R8-67(c).

Duke's 2010 REPS compliance report states that the combined 2009 retail electric sales for itself and the seven wholesale customers for which it provides compliance services was 57,396,449 MWh; hence, the related 2010 REPS obligation was 11,479 solar RECs. Public Staff witness Lucas stated that this number of RECs meets the REPS requirement that 0.02% of 2009 retail sales must be matched with an equivalent number of RECs derived from solar energy in 2010. Witness Lucas stated that, of the 11,479 RECs placed into Duke's compliance subaccount in NC-RETS, 2,870 were out-of-state RECs, in compliance with the provision 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 a utility's REPS requirements.

According to the records in NC-RETS, Duke correctly transferred 11,479 solar RECs into two NC-RETS compliance sub-accounts, one ear-marked toward Duke's 2010 obligation and the other toward the seven wholesale customers' 2010 obligations. No parties disputed whether Duke and the wholesale customers complied with their 2010 REPS requirements, and both the Public Staff and NCSEA stated that Duke and the seven wholesale customers had met the 2010 REPS requirements.

Therefore, the Commission finds and concludes that Duke and the seven wholesale customers for which it is providing REPS compliance services have fully complied with the requirements of the REPS for 2010, and that Duke's 2010 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 fuel charge adjustment proceedings, which is specified in Rule R8-55(c) for Duke to be the calendar year. Therefore, Duke proposed that the test period for its REPS cost recovery proceeding be the calendar year 2010.

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 adjustment proceeding, Docket No. E-7, Sub 982, and in this proceeding, Duke proposed that its rate adjustments take effect on September 1, 2011, and remain in effect for a 12-month period. This period is the "billing period."

The test period and billing period proposed by Duke were not challenged by any party. Therefore, the Commission finds and concludes that the test period and billing period appropriate for this proceeding are the calendar year 2010 and the twelve months ending August 31, 2012, respectively.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence for this finding of fact is found in the testimony and exhibits of Duke witness Felt, the testimony of NCSEA witness Urlaub, and the Commission's orders in Docket No. E-7, Sub 856.

Duke witness Felt testified regarding Duke's strategy for REPS compliance. With regard to the solar requirements, witness Felt stated that this included the construction of 9.95 megawatt (MW) direct current (8.45 MW alternating current) of solar photovoltaic (PV) capacity through the Duke Energy North Carolina Solar Photovoltaic Distributed Generation Program (Solar DG program), approved by the Commission in Docket No. E-7, Sub 856.

NCSEA witness Urlaub testified that Duke's compliance strategy may not be the best and least-cost approach to compliance, but may result in potential problems such as reaching the incremental cost cap ceiling prematurely resulting in less renewable energy being generated. He requested that the Commission consider issuing a statement that indicates that future significant disparities between the costs of self-generation and third-party market prices should make it difficult to justify self-generation as being in the public interest and meeting the public convenience and necessity standard.

In her rebuttal testimony, Duke witness Felt stated that both the Public Staff and the Commission have acknowledged the reasonableness of Duke's current compliance strategy in their review and approval of the Company's REPS compliance plan in Docket No. E-100, Sub 124. Witness Felt further stated that, if the Company makes any further application to construct additional solar generation facilities or any other renewable generation facilities, it will have to meet its burden of proof to justify the construction of those facilities based on the facts and circumstances at the time.

In Docket No. E-7, Sub 856, the Commission found that it is appropriate for Duke to use a limited amount of self-built solar DG as one component of its compliance with the solar requirements of the REPS. As regards NCSEA's proposal, the Commission agrees with witness Felt that a utility that proposes to build additional electric generation has the burden to prove at that time that it is in the public interest. Parties such as NCSEA are free to argue in that proceeding that construction of the facility is not in the public interest, should they so choose. Therefore, because it is not appropriate in this proceeding to address issues regarding the public convenience and necessity of future electric generating facilities, the Commission will decline to adopt NCSEA's proposal.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 9-10

The evidence supporting these findings of fact appears in the testimony and exhibits of Duke witness Smith, Public Staff witness Edwards, and the record in Docket No. E-7, Sub 856.

The Commission's orders in Docket No. E-7, Sub 856 state that not all of the costs of Duke's Solar DG program may be recovered through the REPS riders. First, the effective avoided costs must be recovered through base rates. In addition, the costs in excess of \$170/MWh[1] must also be recovered through base rates in order to ensure that the cost incurred for the Solar DG program does not cause Duke to prematurely reach the cost caps imposed by G.S. 62-133.8(h)(3) and (4). Witness Smith testified regarding how these costs were calculated and subtracted from the levelized annual fixed Solar DG program costs. Through these calculations, she determined that the incremental costs of the Solar DG program for the test year amounted to \$752,710, as shown in Smith Exhibit No. 1, page 1. Duke proposed to recover these costs in the REPS EMF rider.

On cross-examination, witness Smith asserted that, just as the capital costs of a fossil or nuclear plant are fixed and recovered in roughly equal amounts from year to year, without regard to the amount of power the plant generates in a particular test year, it is appropriate for the Solar DG program to be treated in the same manner. Ms. Smith stated that her levelization method was equivalent to multiplying \$170/MWh by the projected output of the Solar DG program, rather than its actual output; that it is unusual to use projections in an EMF proceeding; and that under her levelization method, even if the Solar DG program were to produce no power at all during a

[1] In Docket No. E-7, Sub 856, this figure was referred to as "the effective price per MWh submitted by the third-place bidder in response to Duke's solar RFP" in order to protect the confidentiality of the third-place bid. However, Duke has acknowledged that this figure no longer needs to be kept confidential, and in this Order it is simply referred to as \$170/MWh.

given test year, the Company would recover the same level of costs as if the facilities had operated at maximum output.

Public Staff witness Edwards testified that he believed that Duke had used an improper method of calculating incremental Solar DG program costs. He asserted that the proper method would have been to multiply the actual test-year output of the Solar DG program facilities (not their projected output) by $170/MWh and to then subtract avoided costs. Accordingly, witness Edwards calculated that test-year incremental Solar DG program costs amounted to $585,282, rather than the $752,710 asserted by Duke.

The Commission determines that the Public Staff's proposed approach has some appeal in that it would link cost recovery via the REPS riders directly to the amount of renewable energy produced by Duke's solar DG facilities as if Duke were purchasing renewable energy from a third party. However, Duke is not purchasing from a third party in this case, and over the long term the Commission concludes that Duke's customers would be better served by a cost-recovery approach that is predictable and allows for easy tracking of REPS-related costs and their relation to the REPS incremental cost caps. In the Solar DG program CPCN proceeding, the Commission limited the amount of costs to be recovered through the REPS rider to leave headroom so as to reduce the likelihood of Duke prematurely reaching the cost caps. This limitation forced Duke to recover a portion of its incremental costs from its Solar DG program through base rates. The Commission deems it unwise to recover through base rates non-variable production plant costs as a function of production output that varies from year to year, as called for by the Public Staff's proposed method. For these reasons, the Commission supports Duke's proposed cost-recovery approach for its reasonable and prudent Solar DG program costs. However, the record is not clear as to whether Duke's calculation of 2010 Solar DG program costs based upon the projected output over a full year appropriately captures the fact that the Solar DG facilities came on-line throughout 2010, and that none of them were operational for the entire 2010 calendar year.[1] Therefore, while the Commission will approve Duke's approach for calculating the amount of incremental costs to be recovered via the REPS riders based upon the levelized revenue requirements, avoided costs and RFP ceiling price, the Commission will require Duke to demonstrate in its next REPS proceeding how its 2010 Solar DG program cost calculations account for the various in-service dates of the facilities in the program.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 11-15

The evidence supporting these findings of fact is found in the testimony and exhibits of Duke witnesses Smith and Felt, the testimony and exhibits of Public Staff witnesses Lucas and Edwards, the testimony of NCSEA witness Urlaub, and the record in Docket No. E-7, Sub 856.

Duke witness Smith testified regarding the methodology used by Duke to calculate the incremental costs of compliance with the REPS requirements. Ms. Smith testified that Duke's proposed REPS EMF rider includes incremental administration and labor costs incurred during the test period. These costs of $2,493,975 are shown on page 1 of Smith Exhibit No. 1.

[1] The Commission takes judicial notice of Duke's February 10, 2011 submittal in Docket No. E-7, Sub 856, which lists the in-service dates for each facility in Duke's Solar DG program.

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Duke witness Felt testified regarding the research costs incurred by Duke during the test period, which are $750,765, and research costs planned for the billing period, which are $436,836. These costs are shown in Felt Exhibit No. 2.

NCSEA witness Urlaub testified that a significant portion of Duke's incremental costs, $2,503,340 in the billing period, are identified as "other." He stated that it appears that some of the costs described by Duke witness Felt are essentially one-time costs involving the development and implementation of models or tracking systems. Also, witness Urlaub stated that the research component of what Duke seeks to recover lacks detail and is not explained in the compliance report or elsewhere.

In her rebuttal testimony, Duke witness Felt stated that the term "other incremental costs" in Felt Exhibit No. 2 includes recurring internal labor costs associated with REPS compliance, recurring non-labor costs for Duke's internal REC accounting system, annual fees related to NC-RETS, and miscellaneous non-recurring expenses such as broker fees and consulting services. She referred to the Commission's Order Approving REPS and REPS EMF Riders in Docket No. E-7, Sub 936, in which the Commission approved the amortization of the costs of the Company's internal REC accounting system over a five-year period, to illustrate the recurring nature of some of these costs. Witness Felt also listed specific research efforts undertaken by Duke, including: (a) research regarding cultivation and development of purpose-grown trees and crops as biomass fuels for renewable energy generation; (b) further evaluation and research regarding technological alternatives for co-firing woody biomass with coal; (c) purchase of reports and analysis from the Electric Power Research Institute regarding renewable energy development issues, primarily related to biomass technologies, (d) participation in Phase 2 of a University of North Carolina ocean-side offshore wind feasibility study; and (e) development of a pilot-scale swine waste-to-energy generation technology in cooperation with Duke University at Loyd Ray Farms.

NCSEA witness Urlaub also commented on the general need for more transparency in the filings made at the Commission. He stated that a meaningful analysis of Duke's approach to compliance would be impossible based only on the non-confidential information filed with the Commission and that the public would have a difficult time determining if the public interest is served based on the non-confidential version of Duke's filing.

Duke witness Felt stated that Duke remains very concerned about third-party developers and bidders gaining access to market-sensitive information, such as Duke's willingness to pay for a particular resource to meet the poultry or swine set-aside, to the detriment of the Company's customers. Witness Felt further stated that Duke is statutorily accountable to its customers to meet its REPS obligation in the most reasonable and prudent manner under the circumstances, which necessarily includes maximizing its ability to transact with third parties to secure resources at favorable prices and terms. Because the disclosure of specific information might impair the Company's ability to negotiate and transact at favorable prices, Duke believes it is not in the best interests of its customers to disclose this information.

Witness Felt stated that, in response to the concerns raised by NCSEA witness Urlaub, Duke will comprehensively review the necessity to maintain the confidentiality of all of the redacted information contained in its REPS compliance filings and, to the extent the Company believes that its customers will not be harmed by the disclosure of certain information, make appropriate adjustments to the Company's next REPS compliance plan filing to be made September 1, 2011.

Witness Felt testified that she is satisfied that the REPS compliance costs incurred by Duke during the test period had been prudently incurred. She stated that Duke maintains a diverse and balanced portfolio of renewable resources to meet its REPS requirements. This balanced portfolio includes the use of Duke-owned assets, the purchase of bundled renewable energy and RECs on the market, the purchase of unbundled RECs from in-state and out-of-state suppliers, and cost-effective energy efficiency savings. Additionally, during the test period, Duke largely completed construction of its Solar DG program facilities; continued co-firing applications at certain existing Company-owned fossil generation plants with woody biomass fuels; continued to assess the possibility of biomass co-firing or repowering at other fossil plants; and engaged in research and development activities. Duke produced or procured 11,479 RECs from solar energy resources in 2010, fully meeting its REPS obligations for the year. Duke entered into several agreements during the test period to purchase power or RECs from swine waste generation facilities, and it is engaged in active negotiations with other swine waste generation facilities and with poultry waste generation facilities.

As regards NCSEA's concerns with data transparency, the Commission notes that, in other proceedings, utilities have objected to filing data related to the prices paid for RECs and other renewable energy market data, asserting that it is subject to trade secret protection. Under G.S. 132-1.2, a utility has the right to file information under seal when the information constitutes a trade secret. (State ex rel. Utilities Commission v. MCI Telecommunications Corp., 132 N.C. App. 625, 514 S.E.2d 276 (1999)). The Commission recognizes that disclosure of certain information could affect a public utility's ability to negotiate with providers of renewable energy products, and, therefore, supports Duke's continued maintenance of the proprietary nature of some of this information. The Commission also recognizes the value of making more of this information public so as to improve customer confidence in the expenditures that are being made, as well as to potentially prompt further innovations and reductions in the cost of REPS compliance. The Commission commends Duke's willingness to review and appropriately reduce the confidential portions of its future REPS filings.

The Commission finds and concludes that Duke has appropriately made information available about the research and administrative costs it seeks to recover through the REPS rider in this proceeding, and it has not acted improperly in filing some information under seal. The Commission also finds and concludes that the research activities funded by Duke during the test period and planned for the billing period are renewable research costs recoverable under G.S. 62-133.8(h)(1)(b), and that the research costs included are within the $1 million annual limit.

No party offered evidence that any of Duke's REPS compliance costs were imprudently incurred. To the extent that NCSEA witness Urlaub's concerns about the cost of Duke's Solar DG program may be viewed as an assertion of imprudence, the Commission has addressed these concerns in the discussion of Finding of Fact No. 8 above.

The Commission, therefore, finds and concludes that Duke's under-recovery of REPS compliance costs during the test period are as shown on page 2 of Smith Exhibit No. 2, and that Duke's projected incremental REPS costs for the billing period are as shown on page 5 of Smith Exhibit No. 2.

. EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT 16-19

The evidence supporting these findings of fact appears in the testimony of Duke witness Smith and Public Staff witnesses Edwards and Lucas.

Duke witness Smith provided a detailed explanation of the procedure by which she arrived at her recommended monthly and annual REPS and REPS EMF riders. She discussed the methodology by which Duke calculated its costs of REPS compliance for both the test period and billing period and the procedure used to calculate avoided costs for power purchase agreements already executed and those not yet executed. She outlined Duke's method of allocating REPS compliance costs between its retail customers and the wholesale customers for which it has agreed to provide REPS compliance services, and she discussed the "buy-in" payment made by Blue Ridge EMC when it began purchasing REPS compliance services from Duke. Blue Ridge EMC began receiving compliance services during the test period, and it was required to reimburse Duke through the "buy-in" payment for its share of all incremental REPS costs incurred by Duke through December 31, 2010. Witness Smith further explained the procedure by which the total costs of compliance were allocated among industrial, general and residential customers based on the customer classes' pro rata shares of their aggregate cost caps provided in G.S. 62-133.8(h). She described the procedure used by Duke to ensure that the wholesale customers receive exclusive credit for power supplied to them by SEPA and that Duke's retail customers receive exclusive credit for energy savings resulting from Duke's retail EE programs. She noted that the total compliance costs allocable to retail customers for the test period were reduced by actual REPS revenues received from retail customers during that period to obtain the total under-collection to be recovered through the EMF, and she explained that the total compliance costs applicable to each customer class were divided by the number of accounts in that class to arrive at proposed monthly and annual riders.

Witness Smith's Exhibit No. 2, at page 2, shows that she calculated a total test period under-collection of incremental REPS costs amounting to $2,127,135 for the residential class, $1,401,509 for the general class, and $496,163 for the industrial class. As shown on page 6 of the Exhibit, this resulted in proposed monthly REPS EMF rider charges of $0.10, $0.49, and $7.37 for the residential, general and industrial classes respectively, excluding gross receipts tax and regulatory fees. Page 5 of the same Exhibit shows that witness Smith calculated projected incremental REPS costs for the billing period as $7,133,159 for the residential class, $4,805,286 for the general class, and $1,170,796 for the industrial class. Duke's proposed monthly REPS riders for projected costs, as shown on pages 5 and 6 of the Exhibit, are $0.37, $1.87 and $18.70 for the residential, general, and industrial classes, respectively, excluding gross receipts tax and regulatory fee.

Public Staff witness Edwards testified that his investigation of Duke's filing included evaluating whether Duke properly determined its incremental REPS compliance costs for the test period. This included a review of Duke's Application and testimony, and other data provided by

Duke in response to Public Staff data requests and a review of specific kinds of expenditures, including expenditures for research and development. As a result of his investigation, he proposed an adjustment to test-period Solar DG program costs as discussed in Finding of Fact No. 10 above. Witness Edwards did not take issue with any other aspect of Duke's filing.

Witness Edwards' Revised Exhibit No. 2, at page 1, shows that as a result of his adjustment to Solar DG program costs, he calculated a test-period under-recovery of incremental REPS costs amounting to $2,041,670 for the residential class, $1,343,835 for the general class, and $478,842 for the industrial class. After applying a $383,449 credit from Blue Ridge EMC's "buy in," witness Edwards calculated a test period under-recovery of $1,833,456 for the residential class, $1,203,241 for the general class, and $444,201 for the industrial class. His proposed monthly REPS EMF riders are $0.10, $0.47 and $7.10 for the residential, general and industrial class respectively, excluding gross receipts tax and regulatory fee.

Public Staff witness Lucas testified that he had reviewed Duke's proposed REPS rider for projected expenses in the billing period, and he recommended that it be approved.

As discussed above, the Commission finds and concludes that the Public Staff's proposed adjustment to Duke's test period Solar DG program costs is not appropriate. The Commission, therefore, finds and concludes that Duke's appropriate monthly REPS EMF riders are as set out on page 1 of Smith Exhibit No. 2. The Commission further finds that Duke's appropriate monthly REPS riders are as shown on pages 5 and 6 of Smith Exhibit No. 2. As shown in the table on page 6 of witness Smith's Exhibit No. 2, the combined monthly amounts of the REPS and REPS EMF riders, excluding gross receipts tax and the regulatory fee, amount to $0.47, $2.36 and $26.07 for the residential, general and industrial class, respectively. On an annual basis, these amounts equate to $5.64 for the residential class, $28.32 for the general class, and $312.84 for the industrial class. These amounts are less than the annual per-account cost caps of $10, $50 and $500 for riders in effect in 2011, and the annual per account cost caps of $12, $150 and $1,000 in effect for 2012, both of which were established by G.S. 62-133.8(h)(4).

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT 20

The evidence for this finding of fact appears in the testimony of Public Staff witness Lucas.

Witness Lucas testified that the Public Staff is concerned about how RECs derived from EE programs and from purchases of power from SEPA are allocated between Duke's retail and wholesale customers. Witness Lucas asserted that both of these kinds of RECs are essentially cost-free to Duke. Duke can earn EE RECs only by making EE programs available to retail customers, not to wholesale customers. On the other hand, SEPA RECs can be obtained only by wholesale customers that make purchases from SEPA, not by retail customers. Duke has designed a procedure to ensure that retail customers are not given the benefit of cost-free SEPA RECs and wholesale customers are not given the benefit of EE RECs; however, this procedure is complicated. The Public Staff does not necessarily disagree with Duke's procedure, but has asked for an opportunity to review it with Duke to make sure that it is as accurate as possible. Duke has agreed to discuss the allocation methodology with the Public Staff, and a different methodology may be proposed in Duke's 2012 REPS rider proceeding.

The Commission notes that the parties are not currently in disagreement on how to allocate EE and SEPA RECs. Because Duke might need to use these RECs toward its 2012 REPS obligations, the Commission finds that it is appropriate for Duke and the Public Staff to continue discussing the matter, with the goal of reaching full agreement on an allocation method that is as accurate as possible. The Commission notes further that G.S. 62-133.8 does not allow Duke to use SEPA RECs towards the Company's REPS obligations. Nor does G.S. 62-133.8 allow any entity other than Duke to use its EE RECs toward their REPS obligations. Therefore, all SEPA RECs should be allocated toward the wholesale customers and all EE RECs should be allocated toward Duke's retail customers.

IT IS, THEREFORE, ORDERED as follows:

1. That Duke 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 on September 1, 2011, and expiring on August 31, 2012;

2. That Duke shall establish a REPS EMF rider as described herein, in the amounts approved herein, and that this rider shall remain in effect for a 12-month period beginning on September 1, 2011, and expiring on August 31, 2012;

3. That Duke shall file appropriate rate schedules and riders with the Commission in order to implement the provisions of this Order as soon as practicable, but no later than five (5) days after the date of this Order;

4. That Duke 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 982, and the Company shall file such notice for Commission approval as soon as practicable, but not later than five (5) days after the date of this Order;

5. That Duke's 2010 REPS compliance report is hereby approved;

6. That Duke shall demonstrate in its next REPS rider application that its 2010 Solar DG program cost calculations were based on the actual in-service dates of its solar facilities;

7. That Duke and the Public Staff are encouraged to continue their discussions concerning the allocation of the costs between retail and wholesale customers, particularly with respect to the treatment of EE RECs and SEPA RECs; and

8. That Duke is encouraged to review and appropriately reduce the confidential portions of its future REPS filings.

ISSUED BY ORDER OF THE COMMISSION.
This the 23rd day of August, 2011.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Clerk

kh082311.01

DOCKET NO. E-7, SUB 992

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Petition of Duke Energy Carolinas, LLC, for	)	ORDER GRANTING
Transfer of Renewable Energy Certificates from	)	REQUEST TO TRANSFER
Capricorn Ridge Wind, LLC	)	RENEWABLE ENERGY
	)	CERTIFICATES

BY THE CHAIRMAN: On July 13, 2011, Duke Energy Carolinas, LLC (Duke), filed a petition requesting that the Commission allow the transfer of 250,000 renewable energy certificates (RECs) into the North Carolina Renewable Energy Tracking System (NC-RETS) that have previously been retired in the Electric Reliability Council of Texas, Inc. (ERCOT), REC tracking system. In its petition, Duke stated that the RECs are associated with electricity produced by Capricorn Ridge Wind, LLC (Capricorn Ridge), a 550-MW wind facility located in Texas and registered with the Commission as a new renewable energy facility. Duke's petition included attestations documenting that it purchased (via a third party) 250,000 RECs from energy produced in 2008 and numbered in the ERCOT system as follows: serial numbers 00000001 through 00123378, 00134357 through 00173378, 00180520 through 00265740, and 00265741 through 00268119.

Duke's petition further stated that the RECs were retired in 2008 in the ERCOT REC tracking system for the benefit of Duke, that the RECS have not been retired for the benefit of any other person or any other purpose, and that the retirement of the RECS by the ERCOT REC tracking system was prior to the Commission's adoption of the NC-RETS operating procedures for transferring RECS from ERCOT.

On August 9, 2011, the Public Staff filed a letter stating that it had completed its review of the request by Duke and that the Public Staff recommends that Duke's petition be granted. The Public Staff also noted that Commission Rule R8-67(h)(4) requires energy production data on which RECs are issued to be filed with NC-RETS within two years, and stated its view that Duke needs a waiver of this requirement in order to transfer the Capricorn Ridge RECs from ERCOT to NC-RETS. The Public Staff recommended that the Commission grant the waiver.

After careful consideration, the Chairman finds good cause to allow Duke's request. The Chairman notes that registration of Capricorn Ridge's wind facility was approved by the Commission on April 22, 2009, in Docket No. EMP-17, Sub 0, and that the subject RECs were issued and retired prior to the development of NC-RETS. Further, the Chairman concludes that the limitation in Rule R8-67(h)(4) cited by the Public Staff does not apply to Duke's request because the Capricorn Ridge RECs were not issued by NC-RETS. The two year limitation on the creation of RECs provided in Rule R8-67(h)(4) applies only to RECs initially issued by NC-RETS based on historical generation data provided to that tracking system. In this case, the RECs were issued by ERCOT and are being transferred to NC-RETS.

The Chairman further notes, however, that the Commission has now established a procedure for transferring RECs into NC-RETS from the ERCOT REC tracking system, as well as a number of other REC tracking systems, to ensure that such RECs are legitimate and that a credible audit trail links every REC back to its associated renewable energy output. This procedure should be followed in the future to avoid the necessity of additional requests for the transfer of previously retired RECs.

IT IS, THEREFORE, ORDERED that the request by Duke to transfer into NC-RETS from the ERCOT REC tracking system 250,000 RECs (issued as serial numbers 00000001 through 00123378, 00134357 through 00173378, 00180520 through 00265740, and 00265741 through 00268119) that Duke purchased (via a third party) from Capricorn Ridge and that were retired on Duke's behalf prior to the development of NC-RETS is granted.

ISSUED BY ORDER OF THE COMMISSION.
This the 26th day of August, 2011.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Bh082611.03

DOCKET NO. E-48, SUB 6

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
North Carolina Eastern Municipal Power Agency	)	ORDER ON 2008 REPS
– 2008 REPS Compliance Report	)	COMPLIANCE REPORT

HEARD: Tuesday, August 3, 2010, at 9:30 a.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

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

APPEARANCES:

For North Carolina Eastern Municipal Power Agency:

Christopher J. Ayers and Michael S. Colo, Poyner Spruill, LLP, 301 Fayetteville Street, Suite 1900, Raleigh, North Carolina 27601

For North Carolina Sustainable Energy Association:

Kurt J. Olson, North Carolina Sustainable Energy Association, 111 Haynes Street, Suite 109, Raleigh, North Carolina 27604

For GreenCo Solutions, Inc.:

Richard Feathers, North Carolina Electric Membership Corporation, Post Office Box 27306, Raleigh, North Carolina 27611-7306

For the Using and Consuming Public:

Kendrick D. Fentress, Staff Attorney, Public Staff - North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: In August 2007, North Carolina enacted comprehensive energy legislation, Session Law 2007-397 (Senate Bill 3), which, among other things, established a Renewable Energy and Energy Efficiency Portfolio Standard (REPS), the first renewable energy portfolio standard in the Southeast. Under the REPS, beginning in 2010 all electric power suppliers in North Carolina must meet an increasing amount of their retail customers' energy needs by a combination of renewable energy resources (such as solar, wind, hydropower, geothermal and biomass) and reduced energy consumption.

On February 29, 2008, and March 13, 2008, the Commission issued Orders in Docket No. E-100, Sub 113 adopting rules to implement Senate Bill 3 and the REPS in North Carolina. Commission Rule R8-67(c)(1) provides as follows:[1]

> Each year, beginning in 2009, each electric power supplier shall file with the Commission a report describing the electric power supplier's compliance with the requirements of G.S. 62-133.8(b), (c), (d), (e) and (f) during the previous calendar year.

Pursuant to Rule R8-67(c)(3), each electric membership corporation (EMC) and municipal electric supplier is required to file its REPS compliance report with the Commission on or before September 1 of each year. Rule R8-67(c)(3) further provides:

> The Commission shall issue an order scheduling a hearing to consider the REPS compliance report filed by each electric membership corporation or municipal electric supplier, requiring public notice, and establishing deadlines for intervention and the filing of additional direct and rebuttal testimony and exhibits.

Commission Rule R8-67(c)(1) sets out the information that the REPS compliance report should include. First, the electric power supplier must list the sources, amounts, and costs of renewable energy certificates (RECs) it used to comply with the REPS. For RECs derived from

[1] Commission Rule R8-67(c) was recently amended by Order dated January 31, 2011, in Docket No. E-100, Sub 113. The references to Rule R8-67(c) in this Order are to the Rule in effect at the time the 2008 REPS compliance report was filed.

energy efficiency (EE), the Rule permits electric power suppliers to use estimates of reduced energy consumption through the implementation of EE measures, to the extent approved by the Commission. The REPS compliance report must also include the electric power supplier's actual North Carolina retail sales and number of customer accounts by customer class at year-end. Additionally, the report should state the electric power supplier's current avoided cost rates, as well as the avoided cost rates applicable to energy received pursuant to long-term power purchase agreements. Next, the report should include the actual total and incremental costs incurred to comply with the REPS, as well as a comparison of actual compliance costs to the annual cost caps. The REPS compliance report should discuss the status of the electric power supplier's compliance with the REPS. The report should also identify any RECs to be carried forward. For each renewable energy facility providing RECs used to comply with the REPS, the report should contain the name, address, and owner of the renewable energy facility and an affidavit from the owner of the renewable energy facility certifying that the energy associated with the RECs was derived from a renewable energy resource, identifying the technology used, and listing information regarding payments received and meter readings. For EMCs and municipal electric suppliers, the report should also state the reduced energy consumption achieved after January 1, 2008, through the implementation of demand-side management (DSM) programs.

On August 31, 2009, North Carolina Eastern Municipal Power Agency (NCEMPA) filed its REPS compliance report for calendar year 2008 in Docket No. E-100, Sub 125 on behalf of 32 municipal electric suppliers located in the service territory of Progress Energy Carolinas, Inc. (PEC).[1]

On May 11, 2010, the Commission established this docket and issued an Order scheduling a hearing on NCEMPA's 2008 REPS compliance report, establishing discovery guidelines and deadlines for filing testimony, and requiring public notice. The Commission ordered NCEMPA to file a copy of its 2008 REPS compliance report in this docket as an exhibit to the testimony of NCEMPA's sponsoring witness. The Commission further requested the Public Staff to participate in this proceeding.

On June 3, 2010, NCEMPA filed the direct testimony and exhibits of Gary D. Brunault, Senior Director, R.W. Beck, Inc.

Petitions to intervene were filed by GreenCo Solutions, Inc., on June 10, 2010; the North Carolina Sustainable Energy Association on June 25, 2010; and the Public Works Commission of the City of Fayetteville (FPWC) on November 16, 2010. Each of these petitions to intervene was allowed by the Commission. The intervention of the Public Staff is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

[1] NCEMPA membership consists of the following cities and towns: Apex, Ayden, Belhaven, Benson, Clayton, Edenton, Elizabeth City, Farmville, Fremont, Greenville, Hamilton, Hertford, Hobgood, Hookerton, Kinston, LaGrange, Laurinburg, Louisburg, Lumberton, New Bern, Pikeville, Red Springs, Robersonville, Rocky Mount, Scotland Neck, Selma, Smithfield, Southport, Tarboro, Wake Forest, Washington, and Wilson.

On July 19, 2010, the Public Staff filed the testimony and exhibits of Jay B. Lucas, Electric Engineer, and on July 29, 2010, NCEMPA filed the rebuttal testimony of witness Brunault.

The hearing was held as scheduled on August 3, 2010. NCEMPA presented the testimony and exhibits of witness Brunault, and the Public Staff presented the testimony and exhibits of witness Lucas.

Based upon the foregoing, the testimony and exhibits introduced into evidence at the hearing, and the Commission's record of this proceeding, the Commission now makes the following

FINDINGS OF FACT

1. NCEMPA is a joint agency organized pursuant to the Joint Municipal Electric Power and Energy Act codified in Chapter 159B of the North Carolina General Statutes for the purpose of, among other things, providing wholesale electric power to its member municipalities for resale to their retail electric consumers.

2. NCEMPA has entered into an agreement with each of its member municipalities pursuant to which NCEMPA, on behalf of each of its members, has undertaken to develop, assist in the development of, and coordinate a REPS compliance plan that will enable each of its member municipalities to comply with their REPS requirements, and to report such compliance efforts to the Commission on an annual basis.

3. The combined 2008 retail sales for NCEMPA's member municipalities were 6,990,575 megawatt-hours (MWh), from 228,927 residential accounts, 37,990 commercial accounts, and 548 industrial accounts.

4. The appropriate aggregate incremental cost cap for NCEMPA's member municipalities for 2008 is $4,462,770.

5. NCEMPA may not count purchased power from a wholesale power supplier to satisfy its REPS requirements unless it shows that such power has associated with it a portfolio of supply and demand options that meets the requirements of G.S. 62-133.8.

6. Costs incurred by NCEMPA and its members for implementing existing DSM and EE programs may not be included as REPS compliance costs.

7. It is inappropriate for NCEMPA to include net lost revenues as a cost of REPS compliance.

8. It is appropriate for NCEMPA to adopt the avoided cost rates of PEC for purchases of power from renewable energy facilities.

9. NCEMPA should report its costs of acquiring RECs in 2008 in its 2008 REPS compliance report and should count such costs against its aggregate incremental cost cap for that year.

10. NCEMPA's quantification of its members' potential EE RECs should be accepted in this proceeding, subject to resolution of the issues posed in the August 24, 2010 Order in regard to measurement and verification (M&V) of reduced energy consumption in Docket No. E-100, Sub 113, and reconsideration following the submission of NCEMPA's M&V data supporting such estimates.

11. In reporting purchases from the Southeastern Power Administration (SEPA), NCEMPA may include the total amount of SEPA energy purchased by its member municipalities.

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

The evidence supporting these findings of fact appears in the testimony of NCEMPA witness Brunault. These findings are informational, jurisdictional, and procedural in nature.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3 - 5

The evidence supporting these findings of fact appears in the testimony and exhibits of NCEMPA witness Brunault and Public Staff witness Lucas.

In his direct testimony, NCEMPA witness Brunault testified that NCEMPA purchases approximately 24.3% of its electric power supply requirements from PEC, that PEC's portfolio of supply and demand options meets the statutory REPS requirements, and that the incremental cost cap applicable to the NCEMPA municipalities should be reduced accordingly to avoid over-compliance. Mr. Brunault testified that NCEMPA calculated its REPS incremental cost cap by multiplying its members' reported year-end aggregate number of accounts for each customer class by the per-account annual charges set out by G.S. 62-133.8(h)(4): $10.00 for residential customers, $50.00 for commercial customers, and $500.00 for industrial customers. NCEMPA then reduced the total annual cost cap by $1,079,493, or 24%, which "reflects that portion of the NCEMPA Municipalities' power supply requirements met by Supplemental Power purchased from Progress Energy Carolinas, and is made pursuant to the provisions of [G.S.] 62-133.8(c)(2)(e)." Mr. Brunault attached a copy of NCEMPA's wholesale power supply agreement with PEC as an exhibit to his rebuttal testimony.

Public Staff witness Lucas testified that G.S. 62-133.8(h)(3) allows electric power suppliers to be deemed to be in compliance with the REPS requirements if expenses to meet the requirements reach the annual per-account amounts set out in G.S. 62-133.8(h)(4). He explained that for all account types, NCEMPA initially calculated an aggregate cost cap of $4,442,360 and then reduced the amount by 24.3%, the percentage of its total energy requirements that it acquires from PEC pursuant to a purchased power agreement, for a reported cost cap of $3,362,867. Mr. Lucas pointed out that NCEMPA had no agreement to obtain, or to pay for, REPS compliance services from PEC, and, thus, it was inappropriate for NCEMPA to make such a reduction from its aggregate incremental cost cap. According to Mr. Lucas, allowing NCEMPA to count the RECs associated with its purchased power from PEC, when PEC has only acquired RECs on behalf of its retail customers and wholesale customers with whom it has contracted to provide REPS compliance services, creates the potential for different electric suppliers in the State to use the same RECs twice. Finally, Mr. Lucas noted that, with the inclusion of the retail sales of the wholesale customer of the City of Wilson, the appropriate cost cap for NCEMPA for 2008 should be $4,462,770.

On rebuttal, Mr. Brunault testified that there is no requirement in G.S. 62-133.8 that NCEMPA contract with PEC for the provision of REPS compliance services. According to Mr. Brunault, the statute provides that, if a wholesale supplier's portfolio of supply and demand options meets the requirements of the REPS statute, a municipality purchasing all or a portion of its electric power from that wholesale supplier complies with the statute. Mr. Brunault posited that the statute does not require NCEMPA to demonstrate that PEC is complying on behalf of NCEMPA, and that PEC's compliance plan should be reviewed rather than NCEMPA's compliance plan to determine if adequate RECs have been obtained for the portion of NCEMPA's load provided by PEC. In other words, as a wholesale power supplier, it is PEC's obligation to acquire RECs sufficient to meet the pro rata REPS requirement of the wholesale power purchaser. Mr. Brunault testified that NCEMPA's purchased power agreement with PEC preceded the enactment of Senate Bill 3 and that NCEMPA had no specific contract with PEC for REPS compliance services. He explained that NCEMPA's position is that it is effectively complying because PEC is complying on its behalf pursuant to G.S. 62-133.8(c)(2)(e).

The Commission concludes that NCEMPA's interpretation of G.S. 62-133.8(c)(2)(e) is contrary to the intent of the General Assembly. First, as part of subsection (c), subdivision (2)(e) provides a means for an EMC or municipal electric supplier to comply with its REPS obligation, not a means to reduce its annual incremental cost cap set forth in subsection (h). NCEMPA's annual incremental cost cap, as a REPS compliance aggregator for its member municipal electric suppliers, is the sum of the per-account charges stated in G.S. 62-133.8(h)(4) for each class of customer multiplied by the total number of its members' customer accounts in each customer class determined as of December 31 of the previous calendar year. That is also the amount of incremental costs that must be incurred, collectively, by NCEMPA and its members in a compliance year in order to be "deemed" to be in compliance pursuant to G.S. 62-133.8(h)(3).

Second, Senate Bill 3 establishes a REPS percentage requirement applicable to all retail sales of every electric power supplier in North Carolina. By including subdivision (c)(2)(e), the General Assembly intended to accommodate compliance by EMCs and municipal electric suppliers with existing wholesale power purchase obligations, e.g., those electric power suppliers that could not meet the REPS requirement by purchasing power from renewable energy facilities because they were contractually required to purchase all of their power from a particular wholesale power supplier, such as the arrangement between NCEMPA and its member municipal electric suppliers. Subdivision (c)(2)(e) was not intended as a means for such electric power suppliers to evade or avoid REPS compliance, but that is precisely the effect of NCEMPA's statutory interpretation. Because of this provision, the members of NCEMPA may meet their REPS requirements via NCEMPA, but this requires that NCEMPA meet the REPS percentage requirement for its members' aggregated retail sales by one of the means provided in subdivision (c)(2), such as by generating sufficient power from renewable energy resources or acquiring RECs from renewable energy facilities. NCEMPA must, in essence, acquire the RECs required to meet a percentage of its members' retail sales. NCEMPA, in turn, may only rely on subdivision (c)(2)(e) in meeting its members' aggregated REPS compliance obligation by purchasing wholesale power from a wholesale supplier that is including that portion of NCEMPA's members' retail sales in its own REPS obligation.

In this case, PEC is not including any portion of NCEMPA's members' retail sales in its own REPS obligation, as it is doing with certain other municipal wholesale power customers. NCEMPA cannot force this obligation upon PEC any more than NCEMPA's members can force this obligation upon NCEMPA. NCEMPA has not sought an agreement with PEC to do so, and it would be improper for PEC to incur such compliance costs and pass them on to its own retail customers. Ultimately, NCEMPA's members are responsible under the statute for obtaining a sufficient number of RECs to meet their individual REPS obligations. NCEMPA has agreed to assist its members in meeting their REPS obligation, but the obligation is not met merely by the purchase of power from NCEMPA. Neither is the obligation met merely by purchasing wholesale power from PEC. For NCEMPA to reduce its annual incremental cost cap or its REPS requirement by the amount of energy purchased from PEC in the absence of an agreement with PEC to purchase additional renewable energy or RECs to meet the required percentage of NCEMPA's members' retail load would, in effect, double count the RECs purchased by PEC for its own REPS compliance.

The Commission, therefore, concludes that G.S. 62-133.8(c)(2)(e) does not allow NCEMPA to proportionally reduce its REPS obligation based upon its wholesale power purchases from PEC. In addition, G.S. 62-133.8(c)(2)(e) does not allow NCEMPA to proportionally reduce its its annual incremental cost cap when determining whether NCEMPA has incurred sufficient incremental costs to be deemed to be in compliance with its REPS requirement pursuant to G.S. 62-133.8(h)(3). Adjusting NCEMPA's numbers of customer accounts to include the retail customers of the City of Wilson's wholesale customers, NCEMPA's incremental cost cap for 2008 is $4,462,770.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 6 - 8

The evidence supporting these findings of fact appears in the testimony and exhibits of NCEMPA witness Brunault and Public Staff witness Lucas.

In his testimony, NCEMPA witness Brunault testified that NCEMPA's total and incremental costs consisted of: (i) costs associated with its members' DSM and EE programs, (ii) lost retail revenues, and (iii) research and development costs. He further testified that NCEMPA's avoided cost was based on PEC's 2008 avoided cost, as approved by the Commission, in accordance with Federal Energy Regulatory Commission (FERC) precedent in connection with partial requirements wholesale customers, citing the July 25, 1989 order in Carolina Power & Light Co., FERC Docket No. ER89-460-000.

The Public Staff disagreed with NCEMPA's inclusion of certain DSM costs and lost revenues and initially questioned NCEMPA's adoption of PEC's avoided cost as its own. With regard to the DSM costs, Public Staff witness Lucas testified that NCEMPA's effective REC cost of $410 per MWh, based on the reported DSM costs and energy savings, is unreasonable and imprudent. Noting that a DSM program's primary objective is to save capacity during peak periods, not to save energy, Mr. Lucas recommended allocation of the costs of the programs between the primary purpose of peak load reduction and the secondary purpose of energy savings. Specifically, he recommended that NCEMPA's $4,155,881 in direct load control credits be disallowed for purposes of the incremental cost cap and that the Commission allow no more than the cost that would normally be incurred to accomplish the purported energy savings.

Mr. Lucas further questioned the inclusion of rate rider credits in the amount of $1,854,520 which were also designated as DSM costs, but stated that the Public Staff did not possess sufficient information to make a specific recommendation.

With regard to lost revenues, Mr. Lucas testified that NCEMPA's reported compliance costs included $1,332,199 for lost revenues related to reductions in retail energy sales. Mr. Lucas pointed out that net lost revenues resulting from reduced sales attributable to EE programs are generally considered a disincentive to implementing EE programs. He stated that rate-regulated electric power suppliers are in some cases allowed to recover some portion of their net lost revenues to implement EE programs, but Commission Rule R8-68(c)(3)(vi) designates net lost revenue recovery as an incentive, rather than the recovery of a cost. Mr. Lucas testified that if net lost revenues are not considered to be a cost of an EE program for DSM/EE purposes, neither should they be considered to be a cost of complying with the REPS. He concluded, therefore, that it is inappropriate for NCEMPA to include net lost revenues as a cost of REPS compliance.

In his rebuttal testimony, NCEMPA witness Brunault defended NCEMPA's inclusion of these disputed costs. First, he disagreed with the Public Staff's recommendation that NCEMPA's direct load control credits and rate rider credits be disallowed or limited to include only an allocated portion related to reduced energy consumption. He argued that NCEMPA's direct control credits and rate rider credits qualify as DSM programs under the statute, and that there is no requirement in the statute that NCEMPA allocate its reasonable and prudent costs incurred for REPS compliance between demand and energy reduction for purposes of the incremental cost cap. Mr. Brunault further disagreed that REPS is not designed to bring about peak load reductions. To the extent NCEMPA is reducing its demand during peak periods of demand on PEC's system, it is assisting PEC in reducing the need for additional capacity to be installed on the system, thereby helping to improve the air quality in the region, one of the policy objectives of the statute. Lastly, he argued that Mr. Lucas' calculation that results in the $410 per MWh saved (or $410 per EE REC created) is misleading. Because the DSM programs are focused on demand reduction, the cost per energy savings appears relatively high. The costs are reasonable and prudent, however, when one considers the peak load reductions as well as the energy savings. Energy efficiency programs, on the other hand, are designed to save energy over many hours and are not focused on just peak demand hours. Thus, he argued, it is not appropriate to compare the cost of DSM programs to EE programs on a cost per MWh energy savings basis.

With regard to lost revenues, Mr. Brunault disagreed with Mr. Lucas' reliance on Commission Rule R8-68 as support for his contention that lost retail revenues should not be considered to be a cost for REPS purposes. Mr. Brunault testified:

> Rule R8-68 applies only to an electric public utility and electric membership corporations, and only in the context of their seeking a DSM/EE cost recovery rider pursuant to [G.S.] 62-133.9(d)(2). This rule has no application to a municipality's determination of its incremental costs and whether it has met the cost cap.

Mr. Brunault maintained that net lost revenues are a cost of a program in terms of reduced cash flow.

Notwithstanding NCEMPA's above arguments and calculations, however, the Commission notes that NCEMPA, in fact, derived its stated incremental costs by subtracting its avoided costs, based upon its reported energy savings and PEC's approved avoided cost, from its adjusted incremental cost cap so that the incremental costs incurred appeared to exactly equal its incremental cost cap. Unfortunately, there is no basis for calculating any of these costs in this manner.

G.S. 62-133.8(h)(3) provides that:

> the total annual incremental cost to be incurred by an electric power supplier and recovered from the electric power supplier's retail customers shall not exceed an amount equal to the per-account annual charges set out in subdivision (4) of this subsection applied to the electric power supplier's total number of customer accounts determined as of December 31 of the previous calendar year.

Having calculated an incremental cost cap, as discussed above, NCEMPA proceeded to calculate its actual incremental costs for 2008. In so doing, NCEMPA backed into a value for its incurred incremental costs that exactly equaled its pro-rated incremental cost cap, despite introducing evidence that the actual costs incurred for its DSM and EE programs were two to three times its derived incremental cost cap, as demonstrated by this exchange between Commissioner Culpepper and NCEMPA witness Brunault:

Q. All right. Is it, therefore, your testimony, then, that the municipalities are billing their customers in a fashion that – I guess, have already billed, I guess, their customers, and I guess during 2009, enough money to recover 2008 actual program costs of $9,211,362; is that right?

A. Theoretically, I guess that is correct. Yeah.

Q. Well, then, how – how do – is there any kind of cost cap, then, on municipalities if that's what's going on? Because my understanding is that that's what the – the cost cap is to limit the exposure of customers. In this particular case, if – if – just take your figure, that they should be limited to $3,362 – $867, that is – $3,362,857 – that's the line on – that's the amount on Line 14, right?

A. Correct.

Q. That's the cost cap. I – I'm trying to figure out how – how that matches up with, if the Legislature put a cost cap on REPS compliance for the municipal customers, then how is it that they are actually paying almost $6 million more than that cost cap? Why – how can that be lawful if there is a cost cap, or is the cost cap just not going to apply to municipalities?

A. That's a good question.

In the absence of a federal renewable portfolio standard, the term "incremental costs" is defined in G.S. 62-133.8(h)(1) as follows:

For the purposes of this subsection, the term "incremental costs" means all reasonable and prudent costs incurred by an electric power supplier to:

a. Comply with the requirements of subsections (b), (c), (d), (e), and (f) of this section that are in excess of the electric power supplier's avoided costs other than those costs recovered pursuant to G.S. 62-133.9.

b. Fund 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.

The issue before the Commission, then, is the calculation of incremental costs for NCEMPA and municipal electric suppliers, including a determination of which costs should be included in "all reasonable and prudent costs" and of "avoided costs" for the municipalities.

In this proceeding, NCEMPA has presented the Commission with the issue of how to treat costs associated with DSM and EE programs for which energy savings may be used to meet the municipalities' REPS requirements. Even though energy savings from DSM/EE programs may be used to meet municipalities' REPS requirements, there is no evidence that any of the programs for which NCEMPA included costs as REPS compliance costs were actually implemented after enactment of Senate Bill 3 for the purpose of meeting the REPS requirement, as required by G.S. 62-133.8(h)(1). Rather, the testimony at the hearing confirms that these programs had been in existence for a number for years. In response to questions from Commissioner Culpepper, NCEMPA witness Brunault stated as follows:

Q With respect to the demand side management programs that you cite in your – your testimony and your summary that you've just given, talking about controls on water heaters and heat strips and air conditioners, how – how long has – have those programs been in existence?

A. I don't know the total length of time, but it's a number of years now.

Q. So these – these programs are – are – were not new programs in the Year 2008?

A. They weren't brand new programs, but they were reinitiated in each year by each of the municipalities, as I understand it.

Q. What do you mean by the term "reinitiated"?

A. Well, as – as the municipalities adopt new rate changes – retail rate changes, they adopt, you know, these – these programs. They may – they may alter them periodically, but they reinstate them for – for – you know, moving forward.

Q. Right. But go back to what you initially said, these programs may get reinstated, but you say they have been in existence for some period of time before – before 2008; is that right?

A. Yes, sir.

The Commission, therefore, concludes that the DSM/EE implementation costs incurred by NCEMPA and its members for these existing programs may not be considered as REPS compliance costs. These existing DSM/EE programs were implemented prior to enactment of Senate Bill 3 and the REPS requirement, and the costs incurred for implementation of these existing DSM/EE programs, therefore, were not incurred to comply with the REPS requirements. The Commission believes that it is appropriate to count the energy savings from such existing programs toward REPS compliance, but that it is not appropriate to count any portion of their costs toward the REPS incremental cost cap.

In Senate Bill 3, the General Assembly adopted a complex framework designed to encourage both the development of new electric generating facilities utilizing renewable energy resources and increased investment and deployment of DSM and EE programs, while simultaneously limiting the potential costs to consumers of the new policy mandate. The REPS requirement and its renewable energy mandate, however, is only one section of Senate Bill 3; it is imperative that the Commission read all of the provisions of Senate Bill 3 together in pari materia in order to understand and implement the intent of the General Assembly. In G.S. 62-133.9(b), the General Assembly directed that "[e]ach electric power supplier [including municipal electric suppliers] shall implement demand-side management and energy efficiency measures and use supply-side resources to establish the least cost mix of demand reduction and generation measures that meet the electricity needs of its customers." The challenge in this proceeding is to harmonize this "least cost mix" requirement for municipalities with the requirement that they meet a percentage of their retail sales with more expensive renewable energy generation. The solution to this challenge lies in the application of "avoided costs," and in the definition of "incremental costs."

With enactment of Senate Bill 3, it is reasonable for municipalities to consider implementing new DSM/EE programs to create additional energy savings that may be used to satisfy the REPS obligation. As part of this decision, the municipalities should be expected to weigh the costs of implementing new DSM/EE programs with the costs of procuring electric power or RECs from renewable energy facilities. By the nature of their power supply contracts, NCEMPA and the municipalities may have limited options for purchasing electric power and may be practically limited to purchases of RECs associated with renewable energy generation. Senate Bill 3 also allows municipalities to meet their REPS obligations with energy savings from DSM and EE programs. Therefore, it may be reasonable for NCEMPA and its members to incur incremental costs associated with the implementation of new DSM/EE programs comparable to the incremental costs that would be associated with the purchase of renewable energy RECs in order to meet their REPS requirements. In that event, incremental costs for such new DSM/EE programs would appropriately count toward their incremental cost cap.

NCEMPA argues that the avoided cost that should be subtracted from its DSM/EE program costs in determining incremental costs should be PEC's avoided cost approved by the Commission in its biennial proceedings under the Public Utility Regulatory Policies Act of 1978 (PURPA). The PURPA avoided cost rate determines the rate a utility, such as PEC, must offer to purchase power generated by a qualifying facility. Many renewable energy facilities under Senate Bill 3 are also "qualifying facilities" under PURPA, which may lead to some confusion in considering this issue. The Commission does not set a PURPA avoided cost rate for NCEMPA or its members. The FERC has ordered that, for purchases of power from qualifying facilities, NCEMPA and its members, as partial requirements wholesale customers of PEC, should adopt PEC's established avoided cost as the rate to be paid to qualifying facilities pursuant to PURPA's mandatory purchase obligation. It is not reasonable, however, to use this

PURPA avoided cost rate to calculate incremental costs for REPS compliance associated with the municipalities' new DSM and EE programs.

Senate Bill 3 is, in many ways, focused on compliance by privately-owned utilities. As NCEMPA witness Brunault testified in response to the following question from Commissioner Culpepper:

> Q. Well, it just – I mean, can you help – does there not seem to be a problem here with respect to, if – if the Legislature says that the customers are not supposed to be charged more than a cap, which, you know, is either Line 13 or 14, and yet, actually, your testimony is that they paid twice as much, at least – well, more than twice as much – is that not some kind of problem? Do you see what I'm getting at?
>
> A. I see what you're getting at. The – the statute was generally – as – as I understand it, was – was developed with a focus on investor-owned utilities and – and – and the regulation of their rates. And it is a little bit cumbersome in trying to apply those same standards to – to our municipal clients.

Under G.S. 62-133.9(d), for example, the Commission is directed to establish rates that allow an electric public utility to recover all reasonable and prudent costs incurred for adoption and implementation of new DSM and EE measures. Such costs include, among others, capital costs, including cost of capital and depreciation expenses, administrative costs, implementation costs, incentive payments to program participants, and operating costs. The Commission is directed to allow the electric public utility to capitalize all or a portion of those costs to the extent that those costs are intended to produce future benefits, and it is allowed to approve other incentives to electric public utilities for adopting and implementing new DSM and EE measures. The Commission has approved such riders and incentive mechanisms for PEC and Duke Energy Carolinas, LLC (Duke), and is currently considering the same for Dominion North Carolina Power. The Commission, however, does not set rates for municipal electric suppliers. Moreover, municipalities do not have equity investors, do not earn a rate of return, and do not need the same incentives in order to encourage implementation of cost-effective DSM and EE programs. Similarly, the avoided cost, to the extent that it is ever applied to municipalities' DSM/EE program costs, need not be the same as that established for publicly-owned utilities and their PURPA purchased power agreements.

So, while a municipal is required to balance the costs of demand-side programs with supply-side programs pursuant to G.S. 62-133.9(b) to produce a least-cost mix of resources for its customers and to implement only those demand-side programs that are determined to be cost-effective, it would be reasonable for the municipal to include in the supply-side costs an additional amount equal to the cost of a REC if it has not yet satisfied its REPS requirement. Therefore, it would be possible that there might be an incremental cost associated with the implementation of new DSM/EE programs.

The Commission, therefore, first concludes that there are no incremental REPS compliance costs associated with NCEMPA members' existing DSM/EE programs. These programs were developed prior to enactment of Senate Bill 3, and the municipalities are incurring no greater costs simply because the energy savings may now be counted toward REPS compliance. Second, consistent with the above discussion, NCEMPA and its members may be allowed to prove in future proceedings that there are incremental costs associated with new DSM/EE programs implemented after enactment of Senate Bill 3 for the purpose of satisfying their REPS obligations. The reasonableness of any incremental costs must be weighed against the municipalities' concurrent obligation pursuant to G.S. 62-133.9(b) to provide the "least cost mix of demand reduction and generation measures" for its customers. Third, as determined by the FERC, it is appropriate for NCEMPA and its members to use PEC's approved PURPA avoided cost when purchasing power from a qualifying facility and in determining the incremental cost associated with electricity purchased for REPS compliance from generators using renewable energy resources. However, it is not appropriate to apply that same avoided cost to the costs incurred by NCEMPA and its members to implement DSM/EE programs in calculating incremental costs associated with such programs. Fourth, it is similarly inappropriate to include as REPS compliance costs any lost revenues associated with the implementation of DSM/EE programs. As the Commission concluded in the rulemaking proceeding, Docket No. E-100, Sub 113, net lost revenues are a consequence of the implementation of DSM/EE programs and may serve as a disincentive for a utility that earns revenues by selling energy, not by persuading its customers to not buy its product. Municipal electric suppliers, in particular, should not allow the possibility of lost revenues to affect their decisions relative to whether to implement DSM/EE programs that will provide overall savings to their customers. Although the implementation of DSM/EE programs may result in lost revenues and require the recovery of certain fixed costs over fewer kilowatt-hour sales, the resulting increase in the electric rate will be offset by customer savings from reduced consumption and will result in a net benefit to the municipal's customers.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The evidence supporting this finding of fact appears in the testimony and exhibits of NCEMPA witness Brunault and Public Staff witness Lucas. The Commission also takes judicial notice of joint filings by NCEMPA, North Carolina Municipal Power Agency Number 1 (NCMPA1) and ElectriCities of North Carolina, Inc. (collectively, Power Agencies), and by FPWC, PEC and the Public Staff in this docket, in Docket No. E-43, Sub 6, and in Docket No. E-100, Sub 113 related to this issue.

In this proceeding, Public Staff witness Lucas testified that Rule R8-67(c)(1)(iv) directs electric power suppliers to include the actual total and incremental costs incurred to comply with G.S. 62-133.8(b), (c), (d), (e) and (f) in the annual compliance report. He further testified that, in footnote 3 on page 4 of NCEMPA's 2008 REPS compliance report and in its response to the Public Staff's data request, NCEMPA stated that it plans to report the costs of RECs in the years in which the RECs are actually used for compliance with the REPS requirements, and not in the years when the costs are incurred. Mr. Lucas disagreed with NCEMPA's contention that these costs are properly reported when the RECs are retired, and instead contended that NCEMPA should have reported the costs of acquiring RECs in 2008 when it incurred the costs.

In his rebuttal testimony, NCEMPA witness Brunault explained that Commission Rule R8-67(c)(1) requires an electric power supplier to file a report annually on its "compliance with G.S. 62-133.8(b), (c), (d), (e) and (f) during the previous calendar year." According to witness Brunault, NCEMPA had no REPS obligation in 2008, and, thus, was not required to report the quantity or costs of the RECs it acquired during 2008. Instead, it will report the costs associated with the RECs acquired in 2008 during the years when these RECs are retired for compliance.

On September 24, 2010, Power Agencies filed a Motion for Clarification on this issue in Docket No. E-100, Sub 113. On October 29, 2010, NCEMPA filed a letter in this docket attaching a copy of the Motion for Clarification and requesting that the Commission take judicial notice of the filing and arguments in its deliberations in this docket.

On October 1, 2010, PEC filed a letter in Docket No. E-100, Sub 113 supporting the Motion and suggesting that the requested clarification could be addressed as part of the Commission's review of Rules R8-64 through R8-69.

On November 16, 2010, FPWC filed comments on the Motion in Docket No. E-100, Sub 113. On the same date, FPWC filed a petition to intervene in this docket and requested that the Commission take judicial notice in this docket of its comments filed in Docket No. E-100, Sub 113.

Taking judicial notice of the comments and arguments on this issue filed in this docket, in Docket No. E-43, Sub 6, and in Docket No. E-100, Sub 113, the Commission believes that this issue has been fully briefed and may be resolved in this docket.

In the Motion, Power Agencies note that NCEMPA did not report the cost of RECs purchased in 2008 in its 2008 REPS compliance report because none of those RECs were retired for compliance purposes in 2008. Power Agencies argue that such costs are not required to be reported in the year in which they were incurred, but in the year in which the RECs are retired for REPS compliance, because Rule R8-67(c)(1) relates only to "the electric power supplier's compliance with the requirements of G.S. 62-133.8(b), (c), (d), (e) and (f) during the previous calendar year." (Emphasis added.) Thus, if there is no REPS compliance requirement during the previous calendar year, then no RECs are required to be retired for REPS compliance and no costs have been incurred for REPS compliance during that time period. Costs may only be incurred for REPS compliance during a year in which an electric power supplier has a REPS obligation.

Power Agencies further argue that to deem costs to be incurred when RECs are acquired rather than when they are retired, the position advocated by the Public Staff, is inconsistent with G.S. 62-133.8(h)(3) and could cause an electric power supplier to incur costs on behalf of consumers in excess of the statutory per-account incremental cost cap.[1] Specifically, Power

[1] G.S. 62-133.8(h)(3) provides that, absent a similar federal mandate,

> the total annual incremental cost to be incurred by an electric power supplier and recovered from the electric power supplier's retail customers shall not exceed an amount equal to the per-account annual charges set out in subdivision (4) of this subsection applied to the electric power supplier's total number of customer accounts determined as of December 31 of the previous calendar year. An electric power supplier shall be conclusively deemed to be in compliance with the requirements of subsections (b), (c), (d), (e), and (f) of this section if the electric power supplier's total annual incremental costs incurred equals an amount equal to the per-account annual charges

Agencies argue that this interpretation could result in the incremental cost cap being increased above the statutory limit in a compliance year in which RECs purchased in a prior year are used for compliance:

> For example, if a power supplier purchased $500,000 worth of RECs in 2008 and did not retire those RECs for compliance purposes until 2012, under the Public Staff's argument the power supplier would not be allowed to credit the $500,000 cost of the RECs it retired in 2012 against its cost cap in 2012. Thus, the power supplier's cost cap in 2012 effectively would be $500,000 greater than that set forth in [G.S.] 62-133.8(h)(4) if the electric power supplier was otherwise unable to meet the REPS percentage requirements in that year and was conclusively deemed to be in compliance pursuant to the provisions of [G.S.] 62-133.8(h)(3). Such a result can only result in increased costs to the electric power suppliers' retail rate payers.

Thus, argue the Power Agencies, under the Public Staff's interpretation, an electric power supplier does not receive credit toward the incremental cost cap if it chooses to retire RECs for compliance in a subsequent year. As a result, an electric power supplier will never be able to count the costs it incurs related to purchasing and retiring RECs unless it both purchases and retires the RECs in the same year. By failing to allow an electric power supplier to credit an incremental compliance cost associated with a previously purchased REC against a cost cap in a year in which the electric power supplier retires the REC for compliance purposes, the Public Staff's position could result in passing on unnecessary and increased compliance costs to the electric power suppliers' retail electric customers.

Under the Power Agencies' interpretation of G.S. 62-133.8(h)(3) and Commission Rule R8-67(c)(1), allowing such costs to be credited against the incremental cost cap in future years does not inflate cost recovery or permit double-recovery of costs.[1] Rather, argue the Power Agencies,

> In accordance with the General Assembly's intent, if electric power suppliers incur, in any given year, an amount equal to their respective statutory cost caps for such year in attempting to meet their respective REPS requirements, the electric power suppliers may terminate their respective compliance efforts for that

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> set out in subdivision (4) of this subsection applied to the electric power supplier's total number of customer accounts determined as of December 31 of the previous calendar year. The total annual incremental cost recoverable by an electric power supplier from an individual customer shall not exceed the per-account charges set out in subdivision (4) of this subsection….

[1] In its comments, FPWC provided an example to illustrate Power Agencies' argument that the Public Staff's interpretation of G.S. 62-133.8(h)(3) could allow REC costs to be double counted for purposes of REPS compliance:

> For example, if an electric power supplier's annual cost cap in a particular year such as 2012 is one million dollars ($1 million), the electric power supplier could achieve deemed compliance in accordance with subsection (h)(3) by merely purchasing ten thousand RECs (10,000) at $100 per REC in that year. Three years later, the electric power supplier could theoretically achieve compliance in 2015 with the same RECs purchased in 2012 through the satisfaction of the requirements imposed by G.S. 62-133.8(c)(2)d. by using or retiring the same RECs.

> year and be deemed compliant with the REPS requirements for such year. Again, the purpose of this provision is to limit the amount that retail rate payers in North Carolina will pay annually for REPS.

In its comments, FPWC states that it supports Power Agencies' assertion that the cost of RECs should be included in the electric power supplier's annual cost cap in the year that the RECs are actually used or retired for purposes of being deemed compliant in accordance with G.S. 62-133.8(h)(3) rather than the year in which REC costs are merely incurred. FPWC notes that it is not subject to the Commission's rules regarding the recovery of REPS compliance costs from its retail customers, but the timing of the application of REC costs toward the satisfaction of the annual cost cap for purposes of "deemed compliance" is of great importance to FPWC because of the protection that deemed compliance offers to retail customers. FPWC argues that the Public Staff's narrow reading of subsection (h)(3) is neither consistent with the actual intent of the statute nor the Commission's conclusion in its Order Adopting Final Rules issued February 29, 2008, in Docket No. E-100, Sub 113 that, to assure success in complying with REPS, "electric power suppliers must have some flexibility in timing the acquisition, use for compliance (retirement) and cost recovery for these resources." FPWC argues,

> If an electric power supplier merely incurs the cost to purchase RECs but does not use or retire those RECs for REPS compliance, then the electric power supplier has not incurred costs "to comply with the requirements of subsections (b), (c), (d), (e), and (f)." REC costs are not incurred "to comply" with REPS unless and until the RECs are used (or retired) for the purpose of complying with subsections (b), (c), (d), (e), and (f).

Lastly, FPWC argues that the Power Agencies' interpretation "will enable electric power suppliers to go into the market at any time to acquire RECs when opportunities are perceived by electric power suppliers to be most favorable without concern about causing retail customers to overpay for REPS compliance in subsequent years." Under the Public Staff's position, "electric power suppliers will have a strong incentive to wait to purchase RECs until the year that the RECs are to be retired in order to protect retail customers from paying an [sic] excessive charges for REPS compliance."

The Commission concludes that the position advocated by the Public Staff is consistent with Rule R8-67(c) and is the more reasonable interpretation of G.S. 62-133.8(h). In addition, the Public Staff's interpretation is consistent with the position taken in the annual filings by GreenCo, PEC, and Duke. Subsection (h)(1)(a) provides:

> For the purposes of this subsection, the term "incremental costs" means all reasonable and prudent costs incurred by an electric power supplier to:
>
> a. Comply with the requirements of subsections (b), (c), (d), (e), and (f) of this section that are in excess of the electric power supplier's avoided costs other than those costs recovered pursuant to G.S. 62-133.9.

Based upon the schedule of charges set forth in G.S. 62-133.8(h)(4), subsection (h)(3) authorizes each electric power supplier between 2008 and 2011 to incur costs to be recovered from its customers up to a total of $10.00 per residential account, $50.00 per commercial account, and

$500.00 per industrial account. Though there is no REPS compliance obligation in 2008 and 2009, the General Assembly provided for the electric power suppliers to purchase RECs during this period to be banked and used for compliance in a later year. See G.S. 62-133.8(b)(2)(f), (c)(2)(f). The Power Agencies' arguments rely on the fact that there is no REPS compliance obligation in 2008 and 2009, but ignore the fact that they are authorized to incur costs during those years. In providing an incremental cost cap for the years between 2008 and 2011, the General Assembly anticipated that the electric power suppliers would be incurring incremental costs for renewable energy even before the general REPS obligation was to become effective in 2012 that, but for Senate Bill 3 and the future REPS obligation, would not have otherwise been incurred and provided for a cap on the total amount of those costs. Such costs are incurred in the year in which the renewable energy or RECs are acquired, not the year in which they are used, or retired, for REPS compliance. The General Assembly, therefore, established a total amount of incremental costs, beginning in 2008, that could be incurred and recovered from customers in order to meet the total REPS requirement, beginning with the solar set-aside requirement in 2010. This total is the cumulative amount calculated by multiplying the number of customer accounts times the annual cost cap in each year. To adopt the Power Agencies' position would not increase the total amount of incremental costs that could be incurred to meet the REPS requirement, but would instead leave money on the table, money that had been authorized by the General Assembly to be incurred by the electric power supplier on behalf of its customers in order to satisfy the percentage requirements stated in the bill.

The Commission disagrees with the Power Agencies' argument that the Public Staff's interpretation increases the statutory cost cap; rather, the Power Agencies' interpretation ignores the substantial amount of incremental costs that the General Assembly authorized to be incurred in advance of the first REPS compliance year. While the Power Agencies' interpretation would certainly reduce the amount of costs recovered from customers, it does not fully implement the General Assembly's intent to allow the electric power suppliers to meet the percentage requirements stated in the bill, and not just the spending caps. The General Assembly's intent in Senate Bill 3 was for the electric power suppliers to meet a certain percentage of their retail load with energy derived from renewable energy resources and energy savings from the implementation of DSM and EE measures. The General Assembly did not simply intend for the electric power suppliers to incur a certain amount of incremental costs toward reaching a percentage target, but provided a variety of tools to be used to meet the percentage requirements at the least cost to their customers. The General Assembly expected the electric power suppliers to be able to meet the percentage requirements without exceeding the incremental cost caps. The incremental cost caps, therefore, were provided only as a "safety valve" to protect customers from unexpectedly high compliance costs, not as a compliance strategy for electric power suppliers to use to avoid meeting the percentage requirements.

Commission Rule R8-67(c)(1) is consistent with the above interpretation of G.S. 62-133.8(h). Subsection (c)(1) requires an electric power supplier to report "the sources, amounts, and costs of renewable energy certificates, by source," actually <u>used</u> for REPS compliance during the previous calendar year; subsections (iv) and (v) require the electric power supplier to report total and incremental costs <u>incurred</u> during the previous calendar year for REPS compliance. In 2008 and 2009, those costs incurred will be for banked RECs to be used for REPS compliance in future years.

In its January 31, 2011 Order Amending Rules R8-64 Through R8-69 and Approving Final Operating Procedures for NC-RETS issued in Docket No. E-100, Sub 113, the Commission clarified Rule R8-67(c)(1), noting that Senate Bill 3 applies the incremental cost caps set forth in G.S. 62-133.8(h)(4) to multiple circumstances, and that those applications of the incremental cost cap do not necessarily cover the same time period, nor do they measure the same activities. For example, G.S. 62-133.8(h)(3) uses the incremental cost cap both to limit the incremental costs that may be incurred and then recovered by an electric power supplier as well as to determine REPS compliance. As the Commission stated in that Order:

> Throughout G.S. 62-133.8, it is clear that the General Assembly intended that REPS compliance be based on a calendar year period. ... In subsection (h), the term "incremental costs" is defined primarily as the additional costs incurred for REPS compliance, and should be considered to be the incremental costs incurred during a calendar year for REPS compliance. Thus, the Commission concludes that the use of the word "annual" in G.S. 62-133.8(h)(3) should be interpreted to mean "calendar year" consistent with the General Assembly's intent that REPS compliance and incremental costs should be determined on a calendar year basis.

Pursuant to G.S. 62-133.8(h) and Rule R8-67(c), the Commission, therefore, concludes that, for the purpose of filing REPS compliance reports and calculating total and incremental costs, electric power suppliers should report costs in the year in which such costs are incurred to acquire RECs and not in the year in which such RECs are used, or retired, for REPS compliance. NCEMPA should, therefore, refile both its 2008 and 2009 REPS compliance reports to include such costs consistent with the decision herein.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The evidence supporting this finding of fact appears in the testimony and exhibits of NCEMPA witness Brunault and Public Staff witness Lucas. The Commission also takes judicial notice of its Order Requesting Comments on Measurement and Verification of Reduced Energy Consumption issued August 24, 2010, in Docket No. E-100, Sub 113.

In its 2008 REPS compliance report, NCEMPA stated that it achieved 3,415 MWh in savings through its EE programs and 8,532 MWh in savings through its DSM programs, and that it intended to carry forward the total number of RECs associated with each such program. In his rebuttal testimony, NCEMPA witness Brunault corrected NCEMPA's reported EE RECs from 3,415 MWh to 2,997 MWh, and its total DSM/EE RECs from 11,947 MWh to 11,529 MWh. He attached as Exhibit 1 to his rebuttal testimony M&V data providing the basis for the estimates of reductions in energy consumption in connection with NCEMPA members' EE programs. NCEMPA proposes that the Commission approve the total number of DSM/EE RECs it claims to have earned.

In his testimony, Public Staff witness Lucas contended that NCEMPA did not provide sufficient information in its 2008 REPS compliance report or in its testimony for the Commission to accept NCEMPA's quantification of the reduction of energy consumption, and recommended that NCEMPA's quantification of its potential DSM/EE RECs be accepted as a temporary placeholder, subject to reconsideration after NCEMPA provides the Commission with M&V data supporting such estimates, pursuant to Rule R8-67(c).

Commission Rule R8-67 allows municipal electric suppliers to first estimate the energy savings from EE programs, and then to true-up the savings based on measurement and verification (M&V). In its August 24, 2010 Order in Docket No. E-100, Sub 113, the Commission requested further comments on this issue, including the kind of M&V documentation that should be filed, the appropriate proceeding within which to review the results, and the appropriate method for determining the energy savings achieved by an EMC or municipal electric supplier.

The Commission is concerned with the rigor of the M&V performed by NCEMPA. It is unclear whether Mr. Brunault performed the M&V, whether NCEMPA engaged another independent consultant to do an analysis, or whether NCEMPA simply applied factors determined by PEC in its M&V for a similar EE program it had implemented. The Commission is particularly concerned with NCMEPA's estimates of energy savings from DSM programs. In addition, there is no evidence regarding the thoroughness of the Public Staff's review of the M&V analysis given that its recommendation was to accept the savings numbers as temporary placeholders. Without concluding whether the M&V provided by NCEMPA in this docket is sufficient, the Commission concludes that this issue should be held open, as recommended by the Public Staff, and that quantification of NCEMPA's potential DSM/EE RECs should be accepted in this proceeding, subject to resolution of the issues posed in the August 24, 2010 Order in Docket No. E-100, Sub 113.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The evidence supporting this finding of fact appears in the testimony of NCEMPA witness Brunault and Public Staff witness Lucas. In addition, the Commission takes judicial notice of its Order Approving REPS and REPS EMF Riders, issued August 13, 2010, in Docket No. E-7, Sub 936.

Public Staff witness Lucas testified that SEPA is an agency of the federal government that markets hydroelectric power generated at reservoirs in the southeastern United States operated by the Army Corps of Engineers. He stated that SEPA gives preference to municipalities and cooperatives, and that many of the municipalities and EMCs in North Carolina buy SEPA power. Mr. Lucas explained that there are three sources of energy that SEPA provides to the municipalities and EMCs: stream flow energy from traditional hydroelectric generation; pumping operations energy from water released by a pumped storage system; and replacement energy purchased by SEPA to meet its capacity obligations to its customers when its own hydroelectric generation is insufficient. Mr. Lucas presented as an exhibit a sample SEPA bill showing energy provided from these three sources.

Witness Lucas noted that G.S. 62-133.8(c)(2)(c) allows an EMC or a municipality to meet part of its REPS requirements by "[p]urchas[ing] electric power from a renewable energy facility or hydroelectric power facility, provided that no more than thirty percent (30%) of the requirements of this section may be met with hydroelectric power, including allocations made by the Southeastern Power Administration." Mr. Lucas stated that, in response to a Public Staff data request, NCEMPA acknowledged purchases from SEPA by its members, but did not indicate the number of RECs claimed from the SEPA power. Mr. Lucas contended that any RECs reported in connection with the SEPA power by NCEMPA in its 2008 REPS compliance report should not include pumping operations energy or replacement energy from SEPA. Mr. Lucas recommended that NCEMPA be directed to refile sections of its REPS compliance report to list only the SEPA RECs attributable to stream flow, as well as the costs of such purchases. During cross-examination, Mr. Lucas noted that replacement energy should not be used to show REPS compliance until NCEMPA proved that such energy was derived from a renewable source of energy.

NCEMPA witness Brunault disagreed with witness Lucas's analysis and recommendation. Witness Brunault testified that G.S. 62-113.8(c)(2)(c) allows NCEMPA to meet up to 30% of its REPS requirements through its SEPA allocations and that the statute neither mentions the source of the SEPA energy nor requires that the source of the SEPA energy be identified. He pointed out that the NCEMPA municipalities receive allocations of capacity and energy from the Kerr-Philpott hydroelectric system, which contains no pumped storage facilities; however, Mr. Brunault noted that the NCEMPA members do receive replacement energy, to the extent that there is inadequate stream flow to meet contract minimums. Finally, Mr. Brunault pointed out that there was no way to determine the source of the SEPA energy as the invoices to NCEMPA's members do not reflect the actual amounts of energy delivered to a preference customer from the various energy sources, but rather the aggregate cost of the power delivered by SEPA. As such, it would be impossible to comply with Mr. Lucas' recommendation that NCEMPA report only energy derived from stream flow.

In Docket No. E-7, Sub 936, the Commission reviewed this issue with respect to SEPA allocation credits given by Duke Energy Carolinas, LLC, to wholesale entities for which it provides compliance services. In its August 13, 2010 Order in that docket, the Commission interpreted Senate Bill 3 and concluded that the total amount of energy purchased by a municipality or EMC pursuant to its "allocation from the Southeastern Power Administration" is eligible to be used for compliance with the purchasing municipality's or EMC's REPS requirements, subject to the thirty percent limitation provided in G.S. 62-133.8(c)(2)(c). "The term 'allocation' is a term of art in this context and the General Assembly is presumed to have used it as such in the statute." The Commission concludes that the same analysis and conclusion should be applied in this case. The Commission, therefore, finds and concludes that, in reporting purchases from SEPA, NCEMPA may include the total amount of energy purchased from SEPA.

Public Staff witness Lucas further recommended that NCEMPA be directed to provide the total cost and avoided cost of the SEPA energy purchased by its members. The Commission notes that Senate Bill 3 does not limit the amount of money that an electric power supplier spends on renewable energy or EE to meet its REPS obligation; it only limits the incremental costs associated with such expenditures. Although Rule R8-67(c)(1)(iv) requires NCEMPA to provide the actual total costs incurred for REPS compliance,[1] the costs incurred for SEPA power

[1] Rule R8-67(c)(1), at the time NCEMPA filed its 2008 REPS compliance report, required each electric power supplier to provide, in part, the following information:

are unnecessary and irrelevant for determining NCEMPA's incremental costs or a comparison of NCEMPA's incremental costs with its per-account cost cap. NCEMPA's members did not enter into a long-term power purchase agreement for SEPA power to meet the requirements of Senate Bill 3, such as they might have done for a new solar photovoltaic or other renewable energy facility. Rather, they were simply allowed to count toward REPS compliance the SEPA power already being purchased pursuant to existing agreements. Thus, since the municipalities are paying no more for SEPA power now that they are able to count it toward REPS compliance than they did previously, there is no incremental cost associated with SEPA RECs. In fact, SEPA does not earn RECs associated with the power it sells to NCEMPA's members; RECs associated with SEPA power are merely a convenience adopted by the Commission to be recorded by NCEMPA and its member municipalities (similar to EE RECs) for ease in determining REPS compliance under Senate Bill 3. Similarly, with regard to avoided costs, NCEMPA already reports its members' avoided cost; there is no separate avoided cost associated with the energy they purchase from SEPA. The Commission, therefore, concludes that NCEMPA should not be required to include in its REPS compliance reports or in its calculation of REPS compliance costs the total cost and avoided cost of the SEPA power purchased by its members. To the extent that this is inconsistent with Rule R8-67(c)(1), the Commission believes that the peculiar circumstances related to these SEPA contracts were unanticipated by the Commission's rules and the requirement to file such information should be waived.

IT IS, THEREFORE, ORDERED as follows:

1. That the 2008 REPS compliance report filed by NCEMPA on behalf of its member municipalities does not comply with G.S. 62-133.8 and Commission Rule R8-67; and

2. That NCEMPA shall refile its 2008 and 2009 REPS compliance reports consistent with the findings and conclusions herein on or before September 1, 2011.

ISSUED BY ORDER OF THE COMMISSION.
This the 3rd day of May, 2011.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

sw050311.04

(i) the sources, amounts, and costs of renewable energy certificates, by source, used to comply with G.S. 62 133.8(b), (c), (d), (e) and (f). Renewable energy certificates for energy efficiency may be based on estimates of reduced energy consumption through the implementation of energy efficiency measures, to the extent approved by the Commission;

...

(iii) the current avoided cost rates and the avoided cost rates applicable to energy received pursuant to long-term power purchase agreements;

(iv) the actual total and incremental costs incurred to comply with G.S. 62 133.8(b), (c), (d), (e) and (f);

(v) a comparison of actual compliance costs to the annual cost caps;

DOCKET NO. E-22, SUB 464

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 AGREEMENT) AND STIPULATION OF SETTLEMENT,) APPROVING DSM/EE RIDER, AND) REQUIRING COMPLIANCE FILING))

HEARD: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina on Wednesday, April 13, 2011, at 9:30 a.m.

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

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, 2600 Two Hannover Square, 434 Fayetteville Street, Raleigh, North Carolina 27601

Horace P. Payne, Jr., Dominion North Carolina Power, 120 Tredegar Street, Richmond, Virginia 23219

For the Using and Consuming Public:

David T. Drooz and Lucy E. Edmondson, Staff Attorneys, Public Staff - North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

Leonard Green, Assistant Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602-0629

For Nucor Steel-Hertford:

Joseph W. Eason and Phillip A. Harris, Jr., Nelson Mullins Riley & Scarborough LLP, 4140 Parklake Avenue, GlenLake One, Second Floor, Raleigh, North Carolina 27612

BY THE COMMISSION: G.S. 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 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.

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. 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, 2010, the Commission issued an Order granting partial waiver of Rule R8-69 in Docket Number E-22, Sub 418, granting Virginia Electric and Power Company d/b/a Dominion North Carolina Power's (DNCP) request for a waiver allowing the Company to file its DSM/EE rider application contemporaneously with its applications for approval of DSM/EE measures no later than September 1, 2010. On September 1, 2010, DNCP filed in the above-captioned docket its Application for Approval of Cost Recovery for Demand-side Management and Energy Efficiency Measures (Application), together with the pre-filed direct testimony and exhibits of its witnesses Brandon E. Stites, Ripley C. Newcomb, Michael J. Jesensky, David L. Turner, Rick L. Propst, Paul B. Haynes, and Kurt W. Swanson. As explained in DNCP witness Propst's testimony on page 8 and shown on Company Exhibit RLP-1, Schedule 1, DNCP requested a total annual revenue increase of $1,841,000 effective January 1, 2011, to be recovered through its proposed DSM/EE rider, Rider C. The net effect of DNCP's request would increase the monthly bill of a typical residential customer using 1,000 kilowatt-hours (kWh) of electricity by $0.99.

On September 28, 2010, Nucor Steel-Hertford filed a petition to intervene, which was granted by Commission Order issued October 4, 2010. On November 29, 2010, the Public Staff - North Carolina Utilities Commission (Public Staff) filed a letter on behalf of the parties to this proceeding providing a proposed procedural schedule and requesting issuance of a Commission order setting this matter for hearing and requiring the pre-filing of intervenor and rebuttal testimony. The intervention of the Public Staff is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

On December 3, 2010, the Commission issued its Order Scheduling Hearing, Establishing Discovery Guidelines, Suspending Proposed Rider C, and Requiring Public Notice. Pursuant to such Order, deadlines were established for the filing of petitions to intervene, intervenor testimony and exhibits, and rebuttal testimony and exhibits. Proposed Rider C was suspended pursuant to G.S. 62-134 pending investigation and hearing. A public hearing was scheduled for March 8, 2011, for the purpose of considering the annual DSM/EE cost recovery rider for DNCP.

On January 7, 2011, the Attorney General filed a notice of intervention on behalf of the using and consuming public, which is recognized pursuant to G.S. 62-20.

On February 21, 2011, the Public Staff filed a motion for additional hearing date and for extension of time to file testimony. On February 28, 2011, the Commission issued an Order granting DNCP an extension of time, within which to file its revised testimony and exhibits; granting the Public Staff and other intervenors an extension of time, to file their testimony and exhibits; rescheduling the evidentiary hearing to April 6, 2011; and establishing that the March 8, 2011, hearing would be convened for the sole purpose of receiving testimony from public witnesses. On March 8, 2011, a hearing was held for the purpose of receiving testimony from interested members of the public. No public witnesses appeared.

On March 2, 2011, the Public Staff filed the testimony of Michael C. Maness, Assistant Director, Accounting Division, and the Agreement and Stipulation of Settlement (Stipulation) entered into by the Public Staff and DNCP (the Stipulating Parties), including the Cost Recovery and Incentive Mechanism (Mechanism). On March 14, 2011, DNCP filed the supplemental testimony and exhibits of its witnesses Stites, Newcomb, Jesensky, Turner, Propst, Haynes, and Swanson, filed in accordance with the March 2, 2011 Stipulation. On March 22, 2011, DNCP filed replacement pages to Company Exhibits RLP-1, PBH-1, and RCN-1 and the corrected supplemental testimony of its witnesses Jesensky and Newcomb.

On March 28, 2011, the Commission issued its Pre-Hearing Order Requiring Verified Information (Pre-Hearing Order) from DNCP and the Public Staff in the form of additional testimony and/or pre-hearing exhibits. On March 29, 2011, the Public Staff filed the supplemental testimony of Michael C. Maness, including an attachment which provided a corrected page 13 to his March 2, 2011 pre-filed testimony. On April 4, 2011, the Public Staff filed the additional supplemental testimony of its witness, Maness.

On March 31, 2011, DNCP filed a motion for extension of time in which to file the verified information requested by the Commission's March 28, 2011 Pre-Hearing Order and requested that the evidentiary hearing currently scheduled for April 6, 2011 be rescheduled to April 13, 2011. By Order issued April 1, 2011, the Commission granted such motion.

On April 1, 2011, DNCP filed Corrected Schedules 1 and 2 to the direct testimony of its witness, Turner. On April 5, 2011, DNCP filed the additional supplemental testimony and schedule of its witnesses Jesensky, Kesler, Propst, Stites, which addressed Question Nos. 1, 3, 5, 6, and 7 contained in the Commission's March 28, 2011 Pre-Hearing Order. DNCP's supplemental testimony also indicated that company witness Deanna R. Kesler was adopting the direct and supplemental testimony of Newcomb, including all schedules and corrections thereto, for purposes of the evidentiary hearing.

On April 11, 2011, DNCP filed its additional supplemental schedules addressing Questions 2 through 4 of the Commission's Pre-Hearing Order. On April 12, 2011, DNCP filed a corrected additional supplemental Schedule 2 to its April 11, 2011 filing.

The evidentiary hearing was held as scheduled on April 13, 2011. No public witnesses appeared. The prefiled direct and supplemental testimony of witness Stites, direct and supplemental testimony and corrected exhibits of witness Newcomb, direct and supplemental testimony and corrected exhibits of witness Turner, direct and supplemental testimony and corrected exhibit of witness Propst, direct and supplemental testimony and corrected exhibits of witness Haynes, direct and supplemental testimony and exhibits of witness Swanson, and direct and supplemental testimony and exhibit of witness Jesensky, including all corrections to DNCP's testimony and exhibits as noted above, were received into evidence. Witness Newcomb's direct and supplemental testimony and exhibits were adopted by witness Kesler. The additional supplemental testimony and exhibit of witnesses Jesensky, Kesler, Propst, Stites, and Turner addressing Question Nos. 1, 3, 5, 6, and 7 of the Pre-Hearing Order and the additional supplemental schedules addressing Question Nos. 2 and 4 were also received into evidence. Witnesses Haynes, Jesensky, Turner, Propst, Stites, Kesler, and Swanson presented testimony on behalf of the Company. Witness Maness presented testimony on behalf of the Public Staff. During the hearing, Presiding Commissioner Culpepper requested that the Public Staff review DNCP's Corrected Additional Supplemental Schedule 2, page 8 of 8, filed on April 12, 2011, and file a late-filed exhibit with the Commission if the Public Staff did not agree with DNCP's calculations set forth on this schedule. On May 13, 2011, the Public Staff filed a letter with the Commission indicating that it had reviewed DNCP's corrected Additional Supplemental Schedule 2, and found it reasonable and appropriate for estimation of net lost revenues expected to be incurred over a multi-year future period.

In addition, the Commission takes judicial notice of its five Orders issued February 22, 2011 approving programs filed by DNCP on September 1, 2010: (1) Low Income Program (Docket No. E-22, Sub 463); (2) Air Conditioning Cycling Program (Docket No. E-22, Sub 465); (3) Commercial HVAC Upgrade Program (Docket No. E-22, Sub 467); (4) Residential Lighting Program (Docket No. E-22, Sub 468); and (5) Commercial Lighting Program (Docket No. E-22, Sub 469) (collectively, the Program Approval Orders). The Commission also takes judicial notice of its Order issued September 14, 2011, denying approval of the Company's Commercial Distributed Generation Program filed by DNCP on September 1, 2010, in Docket No. E-22, Sub 466 (Program Denial Order).

On July 12, 2011, DNCP filed a motion for approval to place incremental jurisdictional common costs not directly related to specific new DSM and EE measures in a deferred account.

On July 19, 2011, DNCP filed revised schedules and table of contents.

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. DNCP is a public utility operating in the State of North Carolina as Dominion North Carolina Power and is engaged in the business of generating, transmitting, distributing, and selling electric power and energy to the public for compensation in North Carolina and Virginia, and is subject to the jurisdiction of the North Carolina Utilities Commission as a public utility. DNCP is lawfully before this Commission based upon its application filed pursuant to G.S. 62-133.9 and Commission Rule R8-69.

2. The test period for the purposes of this proceeding is the 12-month period July 1, 2009 through June 30, 2010. The Company filed no test period costs and expenses for the North Carolina jurisdiction.

3. The rate period for the purposes of this proceeding is the 12-month period January 1, 2011 through December 31, 2011.

4. In this Rule R8-69 proceeding, the following are at issue: (a) the reasonableness and prudence of the costs incurred or projected to be incurred associated with DNCP's approved DSM/EE programs and measures; (b) other expenses incremental to DNCP's DSM/EE efforts; (c) the justification and amount of any utility incentives to be included in the DSM/EE rider; and (d) the determination of a rider or riders to allow recovery of such costs and, as appropriate, incentives. DNCP's approved DSM/EE programs for purposes of this proceeding are: (a) Low Income Program; (b) Air Conditioning Cycling Program; (c) Commercial HVAC Upgrade Program; (d) Residential Lighting Program; and (e) Commercial Lighting Program. On September 14, 2011, in Docket No. E-22, Sub 466, the Commission denied DNCP's request for approval of its Commercial Distributed Generation Program. It is not appropriate for DNCP to recover in this proceeding its costs incurred or projected to be incurred related to its Commercial Distributed Generation Program.

5. It is appropriate for DNCP to recover reasonable and prudent costs relative to the five approved DSM and EE programs listed above in Finding of Fact No. 4 in its DSM/EE rider, subject to review and true-up in its 2012 annual rider proceeding. It is also appropriate for DNCP to recalculate its revenue requirements to conform to the five approved programs, to exclude the revenue requirements related to its Commercial Distributed Generation Program, and to conform to the Order issued on September 14, 2011, in Docket No. E-22, Sub 466 in which the Commission denied approval of such program. DNCP should file with the Commission revised allocations, if any, and supporting schedules based on the Commission's denial of the Commercial Distributed Generation Program.

6. The Stipulation and the Mechanism entered into and agreed to by DNCP and the Public Staff and which were filed with the Commission on March 2, 2011, are reasonable and appropriate and should be approved in accordance with their terms, except as modified herein regarding the effective date of the rider, as reflected in Appendix A attached hereto. The Program Performance Incentive (PPI) proposed by the Stipulating Parties is reasonable and appropriate, except for the PPI related to DNCP's Commercial Distributed Generation Program, which was denied by the Commission. The recovery of net lost revenues only through the

DSM/EE EMF riders, subject to the restrictions set forth in the Mechanism and continuing review for reasonableness, as proposed by the Stipulating Parties, is reasonable and appropriate. DNCP did not request a DSM/EE EMF rider in the present proceeding but instead will request its initial DSM/EE EMF rider as part of its application for cost recovery through Rider C in 2012.

7. The Commission will initiate a formal review of the Commission-approved Mechanism not later than October 1, 2014, unless requested to do so earlier by DNCP, the Public Staff, or another interested party.

8. As agreed to by the Stipulating Parties and as set forth in Paragraph No. 2.D. of the Stipulation, it is appropriate that, subject to review in the annual DSM/EE cost recovery proceedings, the rate of return on investment used by DNCP on an ongoing monthly or other reasonable basis to determine DSM/EE capital-related costs will be based on the capital structure, embedded cost of preferred stock, and embedded cost of debt of the Company (net of appropriate income taxes) specified by DNCP's Treasury Department for use in the Company's NCUC ES-1 Reports or other North Carolina retail earnings or return calculations for the period in which the capital investment costs are incurred, and the cost of common equity approved in the Company's then most recent general rate case.

9. The allocation methodology for purposes of allocating DSM/EE costs between DNCP's retail jurisdictions and among customer classes, agreed to by the Stipulating Parties and as set forth in Stipulation Paragraph Nos. 3.B., 3.C., and 3.D. of the Stipulation, is appropriate for purposes of this proceeding.

10. As agreed to by the Stipulating Parties and as set forth in Stipulation Paragraph No. 3.E., for purposes of DNCP's Integrated Resource Plan, and subject to continuing review for reasonableness, DNCP may include utility incentives calculated according to the methods accepted by the Virginia State Corporation Commission (VSCC) in DSM/EE program costs, and may exclude common costs from such program costs.

11. As agreed to by the Stipulating Parties and set forth in Stipulation Paragraph No. 3.F., for purposes of DSM/EE program approval filings, DNCP should file the results of cost-effectiveness tests both including the utility incentives calculated according to the methods accepted by the VSCC and excluding the utility incentives, and should update common costs for its DSM/EE efforts to reflect any increases or decreases in specific and aggregate common costs since the last preceding program approval filing or cost recovery proceeding, whichever is more recent.

12. Commercial customers with annual consumption of 1,000,000 kWh or greater in the billing months of the prior calendar year, and all industrial customers who implement or will implement alternative DSM/EE measures in lieu of Company-offered DSM and EE programs, may, consistent with G.S. 62-133.9(f) and Commission Rule R8-69(d), elect not to be subject to the DSM/EE rider and the DSM/EE EMF rider.

13. In accordance with Paragraph No. 2.C. of the Stipulation, DNCP should file its annual application for recovery of the DSM/EE and DSM/EE EMF riders not less than 84 days

prior to the hearing scheduled in accordance with Rule R8-69. The initial DSM/EE EMF will be filed with the 2012 filing and should include the appropriate North Carolina jurisdictional level of system program costs and system common costs for the period March 1, 2011 through June 30, 2012. Deferral accounting of these program costs is appropriate pursuant to Commission Rule R8-69(b)(6). Pursuant to Commission Rule R8-27(a)(2), the Commission authorizes DNCP, for North Carolina retail jurisdictional regulatory accounting purposes, to utilize Account 182.3 – Other Regulatory Assets to implement the deferred accounting necessary to obtain cost recovery consideration of the Company's reasonable and appropriately incurred incremental jurisdictional administrative and general costs and costs not directly related to specific new DSM and EE programs (collectively, Jurisdictional Common Costs). It is appropriate for DNCP to place all Jurisdictional Common Costs in such deferred account for the period March 1, 2011 to the effective date of the DSM/EE rider in this proceeding and to continue to incorporate the reasonable and prudent amounts of Jurisdictional Common Costs in its ongoing deferral accounting processes adopted pursuant to Commission Rule R8-69(b)(6), subject to review and approval by the Commission in the Company's annual DSM/EE cost recovery proceedings.

14. The system program costs and system common costs, in accordance with Paragraph 3.A. of the Stipulation, should be allocated to the North Carolina jurisdiction as defined in Paragraph Nos. 3.B., 3.C., and 3.D. of the Stipulation for the period March 1, 2011 through December 31, 2011. The method for determining the North Carolina jurisdictional program costs and common costs incurred subsequent to December 31, 2011, will be determined in a future proceeding.

15. It is reasonable and appropriate for Rider C, as proposed by DNCP in Company Exhibit KWS-1, Supplemental Schedule 1, Page 10 of 10, filed on March 14, 2011, to become effective on November 1, 2011, subject to true-up in DNCP's 2012 annual rider proceeding to reflect the Commission's denial of the Commercial Distributed Generation Program. Such rider consists of the following customer class billing factors (including GRT): Residential – 0.053 ¢/kWh; Small General Service and Public Authority – 0.024 ¢/kWh; Large General Service – 0.026 ¢/kWh; 6VP – 0.026 ¢/kWh; NS – 0.000 ¢/kWh; Outdoor Lighting – 0.000 ¢/kWh; and Traffic Lighting – 0.000 ¢/kWh. The billing factors for the portion of 2011 prior to such effective date are effectively zero.

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

These findings of fact are essentially informational, procedural, and jurisdictional in nature and are uncontroverted. The test period and rate period proposed by DNCP and agreed to by the Stipulating Parties are consistent with Commission Rule R8-69.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The evidence for this finding of fact is contained in the Program Approval Orders, wherein the Commission approved five DSM/EE programs whose costs and incentives are at issue, and the Program Denial Order, wherein the Commission denied the Commercial Distributed Generation Program whose costs and incentives are at issue, as well as in Commission Rules R8-68 and R8-69 and in the testimony of DNCP witness Turner.

DNCP witness Turner testified that DNCP seeks cost recovery and incentives for six DSM/EE programs pursuant to Commission Rule R8-69 and G.S. 62-133.9. Witness Turner presented exhibits detailing the six programs and their costs, as well as other incremental administrative and general (A&G) and operations and maintenance (O&M) expenses that the Company has incurred or expects to incur during the billing period due to its DSM/EE efforts.

The Program Approval Orders established that this docket, Docket No. E-22, Sub 464, would focus on cost recovery and incentives, as appropriate, relative to those five approved programs. The Program Denial Order established that this docket, Docket No. E-22, Sub 464, would deny cost recovery and incentives, as appropriate, relative to the denied Commercial Distributed Generation program. Commission Rule R8-69 provides that utilities may file annually to recover costs and to request incentives relative to their approved DSM/EE programs. Therefore, the Commission finds and concludes that the reasonableness and prudence of the costs DNCP has incurred for the five approved programs, or is projected to incur, associated with those five programs and measures, its other incremental expenses, its proposed utility incentives, and the allocation of its costs to various customer classes are at issue in this Rule R8-69 proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence for this finding of fact is contained in the testimony and exhibits of DNCP witnesses Stites, Newcomb (as adopted by witness Kesler), Jesensky, Turner, Propst, Haynes, and Swanson; in the testimony of Public Staff witness Maness; and in the Program Approval and Denial Orders.

In his direct testimony filed with the application, DNCP witness Turner provided evidence regarding the estimated system-level program costs of the six DSM/EE programs filed, as well as the system-level common costs associated with implementing those programs. According to witness Turner, "program costs" are those costs which are directly attributable to individual programs, while "common costs" are those costs associated with the overall effort of designing, implementing, and operating the DSM/EE programs, but are not directly attributable to any individual program.

Public Staff witness Maness testified that after the filing of DNCP's application, the Public Staff investigated DNCP's DSM/EE rate period costs using a team of attorneys, engineers, financial analysts, and accountants who analyzed DNCP's application and subsequent filings. Witness Maness testified that the Public Staff's investigation resulted in the negotiated Stipulation between DNCP and the Public Staff and that such Stipulation incorporated a cost and incentive recovery Mechanism related to DNCP's DSM and EE programs.

Following the filing of the Stipulation, DNCP witness Turner updated his testimony and exhibits to reflect the provisions of the Stipulation. Witness Turner presented the projected costs of the six DSM and EE programs in his Exhibit DLT-1. Further, witness Propst indicated that DNCP's rate period, North Carolina retail, DSM/EE projected revenue requirement would be $1,147,999. DNCP witness Swanson used this revenue requirement to generate customer class billing factors, including the addition of a component for the recovery of gross receipts taxes.

DNCP witness Turner testified that the system costs as shown in Exhibit DLT-1 to his supplemental testimony are consistent with the Stipulation entered into by DNCP and the Public Staff.

The Commission recognizes that DNCP's rate period, North Carolina retail, DSM/EE projected revenue requirement and customer class billing factors are affected by the Commission's decision in Docket No. E-22, Sub 466 that denied the Commercial Distributed Generation Program. Therefore, the Commission finds that it is appropriate for DNCP to recover reasonable and prudent DSM/EE costs related to the five approved programs, subject to review and true-up during DNCP's 2012 DSM/EE rider proceeding. Further, the Commission concludes that it is appropriate for DNCP to recalculate its revenue requirements to conform to the five approved programs listed in Findings of Fact Number No. 4 and to conform to the Order issued on September 14, 2011, in Docket No. E-22, Sub 466 that denied approval of the Commercial Distributed Generation Program. DNCP should file with the Commission revised allocations, if any, and supporting schedules based on the Commission's denial of the Commercial Distributed Generation Program and such filing shall be made in Docket No. E-22, Sub 473.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence for this finding of fact is contained in the testimony and exhibits of DNCP witnesses Stites, Newcomb (as adopted by witness Kesler), Jesensky, Turner, Propst, Swanson, and Haynes and in the testimony of Public Staff witness Maness.

Witness Maness testified that DNCP filed its application and supporting testimony pursuant to G.S. 62-133.9(d) which allows a utility to petition the Commission for approval of an annual rider to recover: (1) its reasonable and prudent costs of new DSM and EE measures and (2) other incentives for adopting and implementing new DSM and EE measures. Commission Rule R8-69 sets forth the general parameters and procedures governing the approval of the annual rider, including: (1) provisions for both a DSM/EE rider to recover the estimated costs and incentives applicable to the utility's rate period in which the DSM/EE rider would be in effect, and a DSM/EE EMF rider to recover the difference between the revenues realized by the DSM/EE rider in effect for a given test period and the actual recoverable amounts incurred during that test period; (2) an allowance for inclusion in the DSM/EE EMF rider of the net under-recovery or over-recovery experienced between the end of the test period and the date 30 days prior to the hearing in the annual proceeding, subject to review in the utility's next annual proceeding; (3) provisions for utility incentives, including the possible recovery of Net Lost Revenues; (4) provision for deferral accounting for net under-recoveries or over-recoveries; and (5) provisions for a return on the deferral account and interest on refunds to customers.

According to Public Staff witness Maness, in its application, DNCP requested approval of Rider C, which was comprised of seven individual customer class billing adjustment factors designed to recover DNCP's reasonable and prudent DSM/EE program costs, as well as a utility incentive for adopting and implementing DSM/EE programs. DNCP proposed a utility incentive that would be determined in the same way as allowed in its Virginia retail jurisdiction: a margin on its incurred DSM/EE program expenses, determined by multiplying those expenses by its

Commission approved return on equity.[1] DNCP also requested approval of a DSM/EE EMF mechanism to true up under-recoveries and over-recoveries of its DSM/EE revenue requirements, although it indicated that there was no actual DSM/EE EMF rider to be approved in the present proceeding as no DSM/EE costs had yet been incurred. In addition, DNCP requested approval to defer costs requested for recovery through its DSM/EE rider.

In direct testimony supporting the Application, DNCP witness Stites stated that although Commission Rule R8-69(c) allows a utility to request an incentive that includes net lost revenues, the Company was not requesting the recovery of any net lost revenues at this time. Witness Stites stated that DNCP would request recovery of net lost revenues at such time that it could determine its actual, rather than estimated, net lost revenues.

In their direct testimonies filed with the Application, DNCP witnesses Haynes and Propst, respectively, discussed the assignment and allocation of system-level costs to the North Carolina retail jurisdiction and the development of the Company's proposed North Carolina retail revenue requirement. DNCP proposed to allocate DSM/EE program costs to each retail jurisdiction on the basis of customer penetration levels in each jurisdiction, while allocating common costs to the North Carolina retail jurisdiction on the basis of the ratio of assigned North Carolina retail program costs (sum of capital costs and expenses) to total system program costs, and then to individual programs on the basis of the relative North Carolina retail program cost revenue requirements for each program. The aggregate of the North Carolina retail program and common costs for each program would then be assigned or allocated to customer classes based first on the classes eligible to participate in each program, and then, if more than one class was eligible to participate in a given program, on the basis of the relative Company production plant allocation factors for those eligible classes, adjusted to remove opted-out customers and non-participating classes.

In his direct testimony filed with the Application, DNCP witness Swanson testified as to the calculation of the customer class billing adjustment factors proposed to collect the DSM/EE revenue requirement from each customer class. Such calculation was based on the forecasted kWh sales for each customer class, net of the forecasted sales for opted-out North Carolina retail industrial and large commercial customers.

As discussed hereinabove, DNCP and the Public Staff negotiated a Stipulation, including a Mechanism. Witness Maness explained that the purpose of the Mechanism is to: (1) allow DNCP to recover its reasonable and prudent costs of its new DSM/EE measures and programs; (2) establish certain requirements in addition to those included in Commission Rule R8-68 for requesting approval of DSM/EE programs; and (3) establish the terms and conditions for the recovery of net lost revenues and an additional PPI associated with new DSM/EE programs.

Public Staff witness Maness further testified that the Cost Recovery section of the Stipulation addresses the recovery of incurred DSM and EE program costs (including common costs) as part of the annual riders, and sets forth how these costs will be recovered on both an

[1] For revenue requirement purposes, DNCP proposed to use its overall cost of capital in North Carolina, rather than its authorized rate of return on common equity, as has been approved in its Virginia retail jurisdiction.

estimated basis (through the DSM/EE rider) and a trued-up basis (through the DSM/EE EMF rider). Witness Maness pointed out that the Stipulating Parties may also 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, witness Maness testified that deferral accounting for over-recoveries and under-recoveries of costs is allowed, and a return on the deferral account will also be allowed, up to the effective date of the applicable DSM/EE EMF rider. Finally, he noted that any over-recovery of DSM/EE costs ordered to be refunded through a DSM/EE EMF rider will include interest, with accrual beginning on the effective date of the rider.

Public Staff witness Maness testified that the Stipulation requires that beginning with its rider filing in 2012, DNCP will (a) perform biennial cost-effectiveness evaluations for each of its approved DSM and EE programs that has been implemented for at least 12 months, (b) perform biennial aggregated portfolio-level cost-effectiveness evaluations for its approved DSM/EE programs (including common costs) that have been implemented for at least 12 months, and (c) include the results in its DSM/EE rider application along with a discussion of whether those results indicate that any of the programs should be discontinued or modified. According to witness Maness, this requirement will enable intervenors and the Commission to examine whether approved programs continue to be cost-effective on a prospective basis.

Public Staff witness Maness explained that the Net Lost Revenues section of the Mechanism includes a limit on the recovery of net lost revenues resulting from an approved measurement unit installed in a given vintage year to those resulting from kWh sales reductions experienced during the first 36 months after the installation of the measurement unit. He explained that this provision is consistent with the Public Staff's view that revenues that are "lost" due to an EE program do not continue to be lost in perpetuity, but are offset in time by revenue gains resulting, for example, from customer growth or other increases in demand.

Public Staff witness Maness also noted that certain general programs and measures, as well as research and development activities, are ineligible for a net lost revenue incentive. With regard to pilot programs and measures, in order to earn a net lost revenue incentive, DNCP 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 DNCP will implement an evaluation, measurement and verification (EM&V) plan based on industry-accepted protocols for the program or measure. Finally, witness Maness stated that no pilot program or measure will be eligible for the net lost revenue incentive unless it is ultimately proven to have been cost-effective.

Public Staff witness Maness pointed out that the Net Lost Revenues section of the Stipulation provides that the eligibility of electricity 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 or new rates approved by the Commission in a general rate case or comparable proceeding, and that net lost revenues will be reduced by net found revenues, as defined in the Mechanism, that occur in the same 36-month period. He also noted that the Mechanism does not provide for the true-up of net lost revenues as DNCP does not intend to request recovery of net lost revenues on the basis of initial program or measure impact estimates, but instead intends to use actual lost sales data when it becomes available. Witness Maness testified that the Mechanism requires that net lost revenues incentive will begin no later than the commencement of the final true-up of the PPI for the same measurement unit, and that net found revenues ultimately will be based on increased kWh sales verified by the EM&V process.

In response to the Commission's inquiry in its Pre-Hearing Order on the appropriateness of retroactively earning net lost revenues based upon actual versus estimated net lost revenues later subject to true-up, witness Maness stated that the Public Staff concluded in this specific case that the benefits of administrative simplification, deferred rate increases, and overall settlement of the case pursuant to the terms of the Stipulation outweigh the fact that the net lost revenues will be recovered in a time period later than the period in which they are experienced. DNCP responded to the Pre-Hearing Order by asserting that recovery of net lost revenues based on an after-the-fact approach using data gathered through EM&V of the programs was previously recommended by the VSCC Staff and approved by the VSCC in the Company's 2009 and 2010 Virginia DSM rider proceedings. DNCP's testimony further stated that the Company proposed a similar approach in North Carolina in an attempt to promote a uniform approach for the recovery of net lost revenues resulting from the implementation of the DSM/EE programs. Both the Public Staff and DNCP also stated that should net lost revenues become significant, the Mechanism provides DNCP and the Public Staff with the flexibility to propose a change in this process. During the hearing, in response to questions from the Commission, both witness Maness, on behalf of the Public Staff, and DNCP's panel of witnesses stated that they had not predetermined or quantified a specific threshold that would trigger such reevaluation but would be willing to work together if such a situation arose at any time in the future.

The Attorney General contended that, while Senate Bill 3 created a new annual rate rider for recovering the costs of DSM and EE programs, the new law did not modify the least cost and cost of service/rate of return principles that are to guide Commission decisions. "In Short, the Act's fundamental principles of cost-based rates and a reasonable profit are present throughout [G.S.] 62.133.9." The Attorney General stated that, under G.S. 62-133.9(d), the Commission has the discretion to determine whether the two incentives proposed in the settlement agreement are "appropriate rewards."

Additionally, the Attorney General stated that DNCP's return on program costs before receiving net lost sales revenues is projected to be 12.47% in 2011 based on the program costs and the performance incentives allowed under the settlement agreement. The Attorney General argued that adding the additional incentive of $273,877 in net lost revenues to a 12.47% return on program cost is excessive and would not result in reasonable rates. The Attorney General maintained in his brief that while the PPI appears to be appropriate, the second incentive under the Stipulation, net lost revenues does not. The Attorney General argued that DNCP had failed to carry its burden of proving that it needs net lost revenues as an incentive, saying, "the evidence shows that DNCP's retail sales will continue to grow at a healthy pace." The Attorney General asserted that DNCP's 2010 Integrated Resource Plan shows that DNCP projects a 2% average annual growth in system-wide retail demand through 2025. Further, even after deducting the projected DSM/EE kWh savings, DNCP projects the annual retail demand growth to over 1% in 2011. The Attorney General asserted that if DNCP's sales growth is not sufficient to provide the Company an opportunity to earn its authorized return, it has the option to apply to the

Commission for an increase in its base rates. Finally, the Attorney General maintained that "automatically awarding DNCP net lost revenues would create a disincentive for ratepayers to engage in energy conservation. By awarding lost revenues, the Commission sends ratepayers the conflicting message that they should conserve electricity, but if they do so they will nonetheless be required to pay DNCP for every kWh they save." Therefore, the Attorney General contended that the Commission should not approve the portion of the Stipulation which provides for DNCP's automatic recovery of net lost revenues.

In regard to the PPI section of the Mechanism, Public Staff witness Maness testified that DNCP would recover a performance incentive for new DSM and EE programs that actually achieve verified energy and peak demand savings. He explained that the PPI is based on the sharing of those savings. Witness Maness noted that certain general programs and measures, research and development activities, and pilot programs and measures are not eligible to receive a PPI. Moreover, except for low-income programs, for any vintage year in which a program's or measure's total resource cost (TRC) test result is less than 1.00, there will be a rebuttable presumption that the PPI for such program or measure for the applicable vintage year will be zero.

Public Staff witness Maness testified that the PPI will be based on the net savings of each program or measure as calculated using the utility cost test (UCT), and will be tracked by measurement units installed in specific years (vintage years). He explained that when a measurement unit installed or expected to be installed in a particular vintage year is first eligible to be included in the DSM/EE rider being considered for a rate year, the amount of the PPI for that measurement unit will be calculated by multiplying the estimated net present value UCT savings for the measurement unit by 8% for DSM programs and measures or 13% for EE programs and measures.

In accordance with paragraph 2.F. of the Stipulation, DCNP filed supplemental testimony and exhibits on March 14, 2011, in order to conform its request in this proceeding to the terms of the Stipulation and to calculate the proposed Rider C in accordance with the Mechanism. Witness Stites, whose testimony provided an overview of the Stipulation, explained that the Mechanism, if approved by the Commission, (1) allows the Company to recover all of the reasonable and prudent costs incurred for adopting and implementing new DSM/EE programs; (2) establishes certain requirements in addition to Commission Rule R8-68, for requests by the Company for Commission approval of DSM/EE programs; and (3) establishes the terms and conditions for the recovery of net lost revenues and the PPI to reward the Company for adopting and implementing new DSM/EE programs based on the sharing of savings achieved by such measures and programs, if the Commission deems such recovery and reward appropriate. Witness Stites noted the extensive negotiations between the Public Staff and the Company culminating in the Stipulation and Mechanism, and stated that the Stipulation provided a fair and equitable resolution of all issues in this proceeding. During the hearing, in response to questions from the Commission, witness Stites stated that the net impact on the monthly bill of a typical residential customer using 1,000 kWh of electricity would be $0.53 under the Stipulation as compared to $0.99 under the initial Application. This figure is consistent with Supplemental Schedule 3 attached to witness Swanson's supplemental testimony.

Witness Propst provided the total revised revenue requirement requested for recovery under Rider C based on the Mechanism, which was reduced from approximately $1.8 million in the initial filing to $1,147,999 under the Stipulation and Mechanism. Modifications to the revenue requirement in accordance with the proposed Stipulation and Mechanism included revised program cost projections and incorporation of the PPI incentive mechanism, as supported by witness Turner; allocation of DSM/EE program costs and common costs, as supported by witness Haynes; and calculation of capital-related costs, using the Company's capital structure and cost of capital as provided in its most recent NCUC ES-1 Report incorporating a cost of common equity of 10.7% as approved in Docket No. E-22, Sub 459, the Company's most recent general rate case. Witness Propst also explained that, consistent with the Stipulation, since no material costs attributable to DSM/EE programs in North Carolina are expected to be incurred during the test period July 1, 2010, through June 30, 2011, the initial DSM/EE EMF rider would be requested as part of the filing for Rider C cost recovery in 2012.

During the hearing, the Attorney General questioned whether the recovery of the PPI resulted in an excessively high rate of profit for DNCP. On redirect, DNCP witnesses Turner and Stites stated that the Attorney General was comparing a 10-year PPI cost to a one-year level of program costs. The witnesses stated that when the one-year PPI cost was compared to a one-year level of program costs, the rough estimates of "profit" for DNCP's six programs were corrected to reflect a range of 0.5% to 20%. In his brief, the Attorney General stated that based on all the factors involved in creating and operating new DSM/EE programs, the PPI proposed in the Stipulation appear to be appropriate incentives; consequently, the Attorney General does not oppose DNCP's recovery of PPI.

As the Commission held in Docket Nos. E-2, Sub 931 and E-7, Sub 831, for both Progress Energy Carolinas, Inc., and Duke Energy Carolinas, LLC, respectively, the proper level of incentives is by nature a balancing act. Incentives should not be excessive, but must be sufficient to motivate DNCP to deploy DSM/EE programs effectively. The Commission is of the opinion that the overall package of incentives proposed by the Stipulating Parties, in addition to the creation of an annual rider with a true-up, and the authority for DNCP to defer and amortize its DSM/EE costs with a return, should be sufficient to properly motivate the Company. Based upon the evidence in this proceeding, the Commission concludes that the agreed-upon incentives, as 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 this Mechanism at least every three years and submit any proposed changes to the Commission for approval. To the extent the Commission-approved Mechanism needs to be revised, it can be reviewed and adjusted, as needed, during the annual rider proceedings.

Accordingly, the Commission concludes that the PPI incentives of 8% for DSM programs and 13% for EE programs, as proposed by the Stipulating Parties, are reasonable and appropriate and should be adopted, subject to review by the Stipulating Parties in three years. With respect to DNCP's proposed approach to the recovery of net lost revenues, the Commission finds that DNCP's proposed approach is reasonable and concludes that the Company should be allowed to recover its net lost revenues based on actual versus estimated net lost revenues, subject to true-up and further review and evaluation in a future rider proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

This finding of fact is supported in part by Paragraph No. 2.E. of the Stipulation, which states that the Mechanism will be revisited by the parties at least every three years, and the Commission's general statutory authority over DNCP's rates. Therefore, unless requested to do so earlier by DNCP, the Public Staff, or another interested party, the Commission will initiate a formal review of the Commission-approved Mechanism not later than October 1, 2014. Such review will specifically address whether the incentives in the Commission-approved Mechanism are producing significant DSM and EE results, whether the customer rate impacts form the DSM/EE rider are reasonable and appropriate and any other relevant issues that may arise.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence for this finding of fact is supported by Paragraph No. 2.D. of the Stipulation; the testimony of DNCP witness Propst; and the testimony of Public Staff witness Maness. Paragraph No. 2.D. of the Stipulation states that subject to review in the annual DSM/EE cost recovery proceedings, the rate of return on investment used by DNCP on an ongoing monthly or other reasonable basis to determine DSM/EE capital-related costs will be based on the capital structure, embedded cost of preferred stock, and embedded cost of debt of the Company (net of appropriate income taxes) specified by DNCP's Treasury Department for use in the Company's NCUC ES-1 Reports or other North Carolina retail earnings or return calculations for the period in which the capital investment costs are incurred, and the cost of common equity approved in the Company's then most recent general rate case. According to witness Propst, the only program included in this proceeding that has capital costs is the air conditioner cycling program. As noted above, witness Propst calculated the revised revenue requirement using this method to calculate DSM/EE capital-related costs for the air conditioner cycling program in accordance with the Stipulation. Witness Maness also stated in his supplemental testimony that DNCP calculated the proposed DSM/EE rider in accordance with the terms of Stipulation and Mechanism using inputs that do not appear to be unreasonable. The Commission finds and concludes that the approach set forth in Paragraph No. 2.D. of the Stipulation is appropriate, subject to review in future annual DSM/EE cost recovery proceedings.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The evidence for this finding of fact is supported by Paragraph Nos. 3.B., 3.C., and 3.D. of the Stipulation; the testimony of DNCP witness Haynes; and the testimony of Public Staff witness Maness. Witness Maness explained that DNCP and the Public Staff could not reach an agreement on the issue of jurisdictional allocation. Witness Haynes testified that DNCP's position is that allocation between jurisdictions should be based on participation in programs, while witness Maness testified that the Public Staff's position is that allocation between jurisdictions should be based on the peak demand and energy requirements of each jurisdiction.

Public Staff witness Maness testified that for purposes of this proceeding, and for purposes of calculating the portion of any DSM/EE EMF resulting from the 2011 calendar year, DNCP's system DSM/EE costs (including common costs) will be allocated to retail jurisdictions (including Virginia customers) only, and not to the wholesale jurisdiction. The generation-level coincident peak factor will be used for DSM programs and the generation-level energy allocation factor for

EE programs. Witness Maness explained that the loads and energy requirements of opted-out North Carolina retail and Virginia retail customers will not be deducted from the factor inputs for the purposes of jurisdictional allocation. Witness Maness also noted that DNCP and the Public Staff had agreed to this method for purposes of this present proceeding only and that prior to the next cost recovery proceeding, the Stipulating Parties have agreed to work together to determine the jurisdictional allocation methodology to be recommended for future proceedings, and will present their joint or individual recommendations to the Commission in the DSM/EE cost recovery proceeding filed in 2011.

Public Staff witness Maness further testified that North Carolina retail costs will be assigned or allocated under the Stipulation based on the particular classes at which each program is targeted. If a program is targeted at more than one class, then the costs will be allocated between the participating classes in a reasonable manner, using the peak demand or energy allocation factors. Witness Maness stated that the class assignment or allocation will take into account the impact of customers who have opted out.

Witness Haynes explained further that since all of the residential programs are targeted to the residential customer class only, the revenue requirement associated with those programs will be assigned to the residential class only, while the revenue requirement for commercial programs targeting multiple customer classes will be allocated among the targeted customer classes using an allocation factor developed using coincident peak demand for DSM programs and using energy usage for EE programs. Witness Haynes also presented the total revenue requirement by customer class for recovery under the proposed DSM/EE rider.

The Commission finds and concludes that the allocation methodology, for purposes of allocating DSM/EE costs between DNCP's retail jurisdictions for the 2011 rate period and among customer classes, as agreed to by the Stipulating Parties in Paragraph Nos. 3.B., 3.C., and 3.D. of the Stipulation, is appropriate for the purposes of this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The evidence for this finding of fact is supported by Paragraph No. 3.E. of the Stipulation, which states that for purposes of DNCP's Integrated Resource Plan, and subject to continuing review for reasonableness, DNCP may include utility incentives calculated according to the methods accepted by the VSCC in DSM/EE program costs, and may exclude common costs from such program costs. No party objected to this proposal, and the Commission finds Paragraph No. 3.E. of the Stipulation to be appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The evidence for this finding of fact is supported by Paragraph No. 3.F. of the Stipulation, which states that for purposes of DSM/EE program approval filings, DNCP shall file the results of cost-effectiveness tests both including the utility incentives calculated according to the methods accepted by the VSCC and excluding the utility incentives, and will update common costs for its DSM/EE efforts to reflect any increases or decreases in specific and aggregate common costs since the last preceding program approval filing or cost recovery proceeding, whichever is more recent. No party objected to this proposal, and the Commission finds Paragraph No. 3.F. of the Stipulation to be appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence for this finding of fact is supported by Paragraph No. 4 of the Stipulation and the direct and supplemental testimony of DNCP witness Turner. Paragraph No. 4. of the Stipulation states that commercial customers with annual consumption of 1,000,000 kWh or greater in the billing months of the prior calendar year and all industrial customers who implement or will implement alternative DSM/EE measures in lieu of Company-offered DSM and EE programs, may, consistent with Commission Rule R8-69(d), elect not to be subject to the DSM/EE rider and the DSM/EE EMF rider. It further provides that for purposes of application of this option, a customer is defined to be a metered account billed under a single application of a Company rate tariff. Additionally, for commercial accounts, once one account meets the opt-out eligibility requirement, all other accounts billed to the same entity with lesser annual usage located on the same or contiguous properties are also eligible to opt out of the DSM/EE rider and the DSM/EE EMF rider. DNCP witness Turner noted in his supplemental testimony that certain customers, including Nucor Steel-Hertford which is a party to this case, have already notified the company of their intent to opt out of DNCP's proposed DSM/EE programs as allowed by Rule 8-69(d)(2) and consistent with their right under G.S. 62-133.9(f). The Commission finds Paragraph No. 4 of the Stipulation to be appropriate..

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 13 AND 14

The evidence for these findings of fact is contained in the motion filed by DNCP on July 12, 2011 and in Paragraph Nos. 2.C. and 2.E. of the Stipulation. Paragraph No. 2.C. states that DCNP shall file its annual application for recovery of the DSM/EE and DSM/EE EMF riders no less than 84 days prior to the hearing scheduled in accordance with Commission Rule R8-69. The Commission finds these paragraphs of the Stipulation to be appropriate.

In their joint proposed order filed in this proceeding, DNCP and the Public Staff recommended that the first DSM/EE EMF to be requested by DNCP as part of its 2012 cost recovery filing include the appropriate North Carolina jurisdictional level of system program costs and system common costs for the period March 1, 2011, through June 30, 2012. In addition, on July 12, 2011, DNCP filed a motion requesting that the Commission (1) issue a generic order pursuant to Commission Rule R8-27(a)(2) approving DNCP's use of Account 182.3 – Other Regulatory Assets to implement the deferred accounting necessary to obtain cost recovery consideration of the Company's reasonable and appropriately incurred Jurisdictional Commons Costs; (2) authorize DNCP, pursuant to Commission Rule R8-69(b)(6), to place all Jurisdictional Common Costs in such deferred account for the period of March 1, 2011 to the effective date of the DSM/EE rider approved in this proceeding; and (3) authorize DNCP to continue to incorporate its reasonable and prudent amounts of Jurisdictional Common Costs in its ongoing deferral accounting processes adopted pursuant to Commission Rule R8-69(b)(6), subject to review and approval by the Commission in the Company's annual DSM/EE cost recovery proceedings. In its motion, DNCP stated that the Public Staff authorized the Company to represent that the Public Staff does not object to or oppose the Company's motion. DNCP also stated that the Company had contacted counsel for the Attorney General and Nucor Steel-Hertford and was authorized to represent that these parties take no position on the Company's motion.

Commission Rule R8-27(a)(2) requires electric utilities under the jurisdiction of the Commission to apply to the Commission for any North Carolina retail jurisdictional use of certain accounts, including Account 182.3 – Other Regulatory Assets. Commission Rule R8-69(b)(6) authorizes the Company to implement deferral accounting for costs to be considered for recovery through the annual rider, and states, in part, that deferral accounting "for any administrative costs, general costs, or other costs not directly related to a new demand-side management or energy efficiency measure must be approved prior to deferral." Further, Paragraph No. 23 of the Mechanism provides that "[i]n accordance with Rule 8-69(b)(6), DNCP may implement deferral accounting for over- and under- recoveries of costs that are eligible for recovery through the annual DSM/EE Rider." Based upon the foregoing, the Commission concludes that deferral accounting of these program costs is appropriate pursuant to Commission Rule R8-69(b)(6). The Commission authorizes DNCP, for North Carolina retail jurisdictional regulatory accounting purposes, to utilize Account 182.3 – Other Regulatory Assets to implement the deferred accounting necessary to obtain cost recovery consideration of the Company's reasonable and appropriately incurred Jurisdictional Common Costs. Further, the Commission finds and concludes that it is appropriate for DNCP to place all Jurisdictional Common Costs in such deferred account for the period March 1, 2011 to the effective date of the DSM/EE rider in this proceeding and that DNCP should continue to incorporate the reasonable and prudent amounts of Jurisdictional Common Costs in its ongoing deferral accounting processes adopted pursuant to Commission Rule R8-69(b)(6), subject to review and approval by the Commission in the Company's annual DSM/EE cost recovery proceedings.

With respect to the timing of DNCP's first DSM/EE EMF, since the DSM/EE programs filed by DNCP with the Commission in Docket No. E-22, Subs 463, 465, 467, 468, and 469 were approved by the Commission in late February 2011, and the program noted in Sub 466 was denied in September 2011, the Commission concludes that the proposal by DNCP and the Public Staff is reasonable. Additionally, the Commission concludes that, in accordance with Paragraph 3.A of the Stipulation, the system program costs and system common costs shall be allocated to the North Carolina jurisdiction as defined in Paragraph Nos. 3.B., 3.C., and 3.D. of the Stipulation for the period March 1, 2011, through December 31, 2011. As provided for in the Stipulation, the method for determining the North Carolina jurisdictional program costs and common costs incurred subsequent to December 31, 2011, will be determined in a future proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The evidence for this finding of fact is supported by the supplemental testimony of DNCP witness Swanson, and the supplemental testimony of Public Staff witness Maness. Witness Swanson testified and set forth a supplemental schedule proposing that in accordance with the Stipulation, the following customer class billing factors (including gross receipts taxes) be put into effect: Residential – 0.053 ¢/kWh; Small General Service and Public Authority – 0.024 ¢/kWh; Large General Service – 0.026 ¢/kWh; 6VP – 0.026 ¢/kWh; NS – 0.000 ¢/kWh;

Outdoor Lighting – 0.000 ¢/kWh; and Traffic Lighting – 0.000 ¢/kWh. Public Staff witness Maness testified that the Public Staff recommended that the rates proposed by the Company be approved by the Commission. DNCP requested in accordance with Paragraph No. 2:G. of the Stipulation that proposed Rider C become effective for usage on the first day of the next month following 30 days after the Commission's Order in this proceeding. The Commission finds it is appropriate for DNCP to implement such billing factors, effective November 1, 2011, subject to true-up in DNCP's 2012 annual DSM/EE rider proceeding to reflect the Commission's denial of the Commercial Distributed Generation Program.

IT IS, THEREFORE, ORDERED as follows:

1. That the Stipulation and Mechanism jointly filed by DNCP and the Public Staff, except as modified herein regarding the effective date of the rider, attached hereto as Appendix A, are hereby approved.

2. That DNCP shall file with the Commission revised allocations, if any, and supporting schedules based on the Commission's denial of the Commercial Distributed Generation Program by Order issued September 14, 2011, in Docket No. E-22, Sub 466. Such filing shall be made in Docket No. E-22, Sub 473.

3. That DNCP shall be, and is hereby, consistent with the findings and conclusions set forth herein, authorized to utilize, for North Carolina jurisdictional regulatory accounting purposes, Account 182.3 – Other Regulatory Assets.

4. That DNCP's proposed Rider C, modified in accordance with the Mechanism and as set forth on Company Exhibit KWS-1, Supplemental Schedule 1, Page 10 of 10, filed on March 14, 2011, shall be, and is hereby allowed to become effective on November 1, 2011, subject to true-up in DNCP's 2012 annual DSM/EE rider proceeding.

5. That DNCP shall work with the Public Staff to prepare a proposed Notice to Customers of the Rider C rates approved herein. The Company shall file such notice with the Commission no later than 10 days from the date of this Order, for Commission approval by further order.

6. That, unless requested to do so earlier by Dominion, the Public Staff, or another interested party, the Commission shall initiate a formal review of the Commission-approved Mechanism not later than October 1, 2014.

ISSUED BY ORDER OF THE COMMISSION.
This the 14th day of October, 2011.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Commissioner Lorinzo L. Joyner did not participate in this decision.

kh101411.02

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-22, SUB 464

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Virginia Electric and Power	)	
Company, d/b/a Dominion North Carolina	)	AGREEMENT AND
Power for Approval of Demand-Side	)	STIPULATION OF
Management and Energy Efficiency Cost	)	SETTLEMENT
Recovery Rider Pursuant to G.S. 62-133.9	)	
And Commission Rule R8-69	)	

Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (DNCP or the Company) and the Public Staff, collectively referred to as the Stipulating Parties, through counsel and pursuant to G.S. 62-69, respectfully submit the following Agreement and Stipulation of Settlement (Stipulation) for consideration by the North Carolina Utilities Commission (Commission) in the above-captioned docket. The Stipulating Parties hereby agree and stipulate as follows:

1. **BACKGROUND**

A. On September 1, 2010, DNCP filed an application (Application) in Docket No. E-22, Sub 464, for approval of a cost recovery rider (Rider C) for demand-side management and energy efficiency (DSM/EE) measures, pursuant to G.S. 62-133.9 and Rule R8-69, and the direct testimony and exhibits of Brandon E. Stites, Ripley C. Newcomb, Michael J. Jesensky, David L. Turner, Rick L. Propst, Paul B. Haynes, and Kurt W. Swanson in support of the Application.

B. On September 28, 2010, Nucor Steel – Hertford (Nucor) filed a petition to intervene, which was allowed by Commission Order issued October 4, 2010. On January 7, 2011, pursuant to G.S 62-20, the Attorney General (AG) filed notice of intervention.

C. On November 29, 2010, the Public Staff filed a letter with the Commission, by which it, DNCP, and Nucor suggested a procedural schedule. By order issued on December 3, 2010, the Commission suspended the proposed Rider C pending investigation and hearing, established procedural deadlines and discovery guidelines, required public notice, and scheduled a hearing in Docket No. E-22, Sub 464, for March 8, 2011.

D. As a result of negotiations conducted after the filing of DNCP's Application and supporting direct testimony and exhibits, after subsequent discovery

and investigation, and prior to the date of this Stipulation, the Stipulating Parties agree and stipulate as follows.

2. **COST RECOVERY AND INCENTIVE MECHANISM**

A. DNCP's annual DSM/EE rider requested in Docket No. E-22, Sub 464, shall be established by the Commission's order in this proceeding according to this Stipulation and the terms and conditions set forth in the Cost Recovery and Incentive Mechanism (Mechanism) attached hereto. The terms and conditions of the Mechanism are hereby incorporated into this Stipulation.

B. The purposes of the Mechanism are: (1) to allow DNCP 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; (2) to establish certain requirements, in addition to those of Commission Rule R8-68, for requests by DNCP for Commission approval of DSM and EE programs; and (3) to establish the terms and conditions for the recovery of net lost revenues and for an additional incentive (the Program Performance Incentive, or PPI) to reward DNCP for adopting and implementing new DSM and EE measures and programs, based on the sharing of savings achieved by those measures and programs, if the Commission deems such recovery and reward appropriate.

C. DNCP shall file its annual application for recovery of the DSM/EE and DSM/EE Experience Modification Factor (EMF) riders not less than 84 days prior to the hearing scheduled in accordance with Commission Rule R8-69. The initial DSM/EE EMF will be filed with the 2012 filing.

D. Subject to review in the annual DSM/EE cost recovery proceedings, the rate of return on investment used by DNCP on an ongoing monthly or other reasonable basis to determine DSM/EE capital-related costs will be based on the capital structure, embedded cost of preferred stock, and embedded cost of debt of the Company (net of appropriate income taxes) specified by DNCP's Treasury Department for use in the Company's NCUC ES-1 Reports or other North Carolina retail earnings or return calculations for the period in which the capital investment costs are incurred, and the cost of common equity approved in the Company's then most recent general rate case.

E. The Stipulating Parties shall review the terms and conditions of this Mechanism at least every three years and shall submit any proposed changes to the Commission for approval.

F. DNCP shall file, by March 14, 2011, revised testimony and exhibits calculating the proposed riders in accordance with the Mechanism.

G. The effective date of the DSM/EE rider shall be November 1, 2011.

3. **ALLOCATION METHODOLOGIES**

A. For purposes of recovery through the DSM/EE rider, estimated 12-month system-level common costs shall be allocated to each program on the basis of the estimated relative 12-month operating costs of each individual program (including O&M, depreciation, property taxes, and insurance expenses), subject to continuing review of the overall reasonableness of the annual allocation. This allocation shall be trued up at the time that finalized and trued-up costs for a given time period are included in the DSM/EE Experience Modification Factor (EMF).

B. For purposes of recovery through the DSM/EE rider in this proceeding and for purposes of calculating the portion of any DSM/EE EMF resulting from the 2011 calendar year, DNCP's system costs for approved DSM and EE programs and measures, including allocated common costs, shall be allocated, by program, to retail jurisdictions as follows: (i) the North Carolina retail jurisdiction, (ii) the Virginia retail jurisdiction, and (iii) Virginia non-jurisdictional customers excluding contract classes that have elected not to participate and excluding customers in participating contract classes that are exempt or have opted out.[1] The wholesale jurisdiction shall not be allocated any costs for approved DSM and EE programs and measures, including allocated common costs. The allocation factors used to allocate the estimated rate period costs of DSM and EE programs shall be the generation-level retail coincident peak and energy allocation factors, respectively, for the most recently completed test year at the time the annual cost recovery filing is made. Subsequent to this proceeding, the Stipulating Parties will work together to determine a reasonable and appropriate jurisdictional allocation methodology to be applied in future DSM/EE cost recovery proceedings, and shall present their joint or individual recommendation(s) to the Commission as part of the DSM/EE cost recovery proceeding filed in 2011.

C. For purposes of recovery through the DSM/EE rider, DNCP's North Carolina retail jurisdictional costs for approved DSM and EE programs and measures (including allocated common costs), as determined in accordance with requirements 3.A and 3.B of this Stipulation,

[1] Virginia Non-jurisdictional customers are not subject to the jurisdiction of the Virginia State Corporation Commission. These are customers that have contracts with Virginia Electric and Power Company for service. The County and Municipal class, the Commonwealth of Virginia class, the NASA class, and the Non-jurisdictional Outdoor Lighting class are the "contract classes that have elected not to participate" and are not participating in DSM/EE programs. The MS class is what is meant by "customers in participating contract classes" and represents large military and federal government customers that take service under Virginia jurisdictional rates. Certain of the MS class of customers are exempt or may opt out of participation in DSM/EE programs and payment of DSM/EE cost recovery riders.

shall be assigned or allocated to North Carolina retail customer classes based on the particular classes at which each program is targeted. If a program is targeted at more than one customer class, the costs of that program (including common costs) shall be allocated among the targeted classes in a reasonable manner. The allocation factor used to allocate the costs of such DSM programs shall be the generation-level retail coincident peak factor for the applicable calendar year. The allocation factor used to allocate the costs of such

EE programs shall be the generation level energy allocation factor for the applicable calendar year. The assignments and allocations of costs shall be trued up at the time that finalized and trued-up costs for a given time period are passed through the DSM/EE EMF.

D. For purposes of the allocation/assignment procedure described in paragraph 3.C above, and subject to continuing review, DNCP shall exclude the peak demand and energy usage of customers electing to opt out in accordance with paragraph 4 below. For purposes of recovery through the DSM/EE rider in this proceeding, the North Carolina retail jurisdictional allocation factors developed pursuant to paragraph 3.B above shall not reflect the effect of opted-out customers in the North Carolina retail jurisdiction or exempt and opted-out customers in the Virginia retail jurisdiction. Subsequent to this proceeding, the Stipulating Parties will work together to determine a reasonable and appropriate method of treating North Carolina retail jurisdictional opted-out customers and Virginia retail jurisdictional exempt and opted-out customers in the development of the North Carolina retail jurisdictional allocation factors, and shall present their joint or individual recommendation(s) to the Commission as part of the DSM/EE cost recovery proceeding filed in 2011.

E. For purposes of DNCP's Integrated Resource Plan, and subject to continuing review for reasonableness, DNCP may include utility incentives calculated according to the methods accepted by the Virginia State Corporation Commission (VSCC) in DSM/EE program costs, and may exclude common costs from such program costs.

F. For purposes of DSM/EE program approval filings, DNCP shall file the results of cost-effectiveness tests both including the utility incentives calculated according to the methods accepted by the VSCC and excluding the utility incentives, and will update common costs for its DSM/EE efforts to reflect any increases or decreases in specific and aggregate common costs since the last preceding program approval filing or cost recovery proceeding, whichever is more recent.

4. OPT-OUT ELIGIBILITY REQUIREMENT

Commercial customers with annual consumption of 1,000,000 kWh or greater in the billing months of the prior calendar year and all industrial customers, who implement or will implement alternative DSM/EE measures in lieu of Company-offered DSM and EE programs, may, consistent with Commission Rule R8-69(d), elect not to be subject to the DSM/EE rider and the DSM/EE EMF rider. For purposes of application of this option, a customer is defined to be a metered account billed under a single application of a Company rate tariff. For commercial accounts, once one account meets the opt-out eligibility requirement, all other accounts billed to the same entity with lesser annual usage located on the same or contiguous properties are also eligible to opt out of the DSM/EE rider and the DSM/EE EMF rider.

5. AGREEMENT IN SUPPORT OF SETTLEMENT; NON-WAIVER

A. The Stipulating Parties shall act in good faith and use their best efforts to recommend to the Commission that this Stipulation be accepted and approved. The Stipulating Parties further agree that this Stipulation is in the public interest because, consistent with the intent of North Carolina Session Law 2007-397 (Senate Bill 3), it promotes the adoption and implementation of cost-effective new DSM and EE programs by DNCP, by allowing for the recovery of the costs associated with those programs, as described in G.S. 62-133.9(d) and (d)(1), and by allowing for the recovery of incentives as described in G.S. 62-133.9(d)(2)(a) and (c). The Stipulating Parties intend to support the reasonableness of this Stipulation before the Commission and in any appeal from the Commission's adoption or enforcement of this Stipulation.

B. Neither this Stipulation nor any of its terms or conditions shall be admissible in any court or before the Commission except insofar as the Commission is addressing litigation arising out of the implementation of the terms herein or the approval of this Stipulation. This Stipulation shall not be cited as precedent by any of the Stipulating Parties with regard to any issue in any other proceeding or docket before this Commission or in any court.

C. The provisions of this Stipulation do not reflect any position asserted by any of the Stipulating Parties, but reflect instead the compromise and settlement among the Stipulating Parties as to all of the issues covered hereby.

D. The Stipulation is the product of negotiation between the Stipulating Parties, and no provision of this Stipulation shall be strictly construed in favor or against any Party.

6. RECEIPT OF TESTIMONY AND WAIVER OF CROSS-EXAMINATION

The Stipulating Parties agree that all pre-filed testimony and exhibits may be received in evidence without objection. Each Stipulating Party waives all right to cross-examine any witness with respect to such pre-filed testimony and exhibits. If, however, questions are asked by any Commissioner, or if questions are asked or positions are taken by any person who is not a Stipulating Party, then any Stipulating Party may respond to such questions by presenting testimony or exhibits and cross-examining any witness with respect to such testimony and exhibits, provided such testimony, exhibits, and cross-examination are not inconsistent with this Stipulation.

7. **STIPULATION BINDING ONLY IF ACCEPTED IN ITS ENTIRETY**

This Stipulation is the product of negotiation and compromise on a complex set of issues, and no portion of this Stipulation is or will be binding on any of the Stipulating Parties unless the entire Agreement and Stipulation is accepted by the Commission. If the Commission rejects the Stipulation in whole or in part, the Stipulating Parties reserve the right to submit or resubmit their testimony and exhibits (including any direct

testimony by the Public Staff and rebuttal testimony by the Company) reflecting that the entire Agreement and Stipulation was not accepted by the Commission, and to conduct discovery regarding such testimony and exhibits.

8. **COUNTERPARTS**

This Stipulation may be executed in one or more counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument. Execution by facsimile signature shall be deemed to be, and shall have the same effect as, execution by original signature.

The foregoing is agreed and stipulated to this the __th day of ________, 2011.

Dominion North Carolina Power

By:________________________________

Public Staff – North Carolina Utilities Commission

By: ________________________________

STIPULATION EXHIBIT 1

COST RECOVERY AND INCENTIVE MECHANISM FOR DEMAND-SIDE MANAGEMENT AND ENERGY EFFICIENCY PROGRAMS

The purpose of this Mechanism is to (1) allow Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (DNCP), to recover all reasonable and prudent costs incurred for adopting and implementing new demand-side management (DSM) and new energy efficiency (EE) measures in accordance with G.S. 62-133.9, Commission Rules R8-68 and

R8-69, and the additional principles set forth below; (2) establish certain requirements, in addition to those of Commission Rule R8-68, for requests by DNCP for Commission approval of DSM and EE programs; and (3) establish the terms and conditions for the recovery of net lost revenues and an additional incentive to reward DNCP for adopting and implementing new DSM and EE measures and programs, in cases where the Commission deems such recovery and reward appropriate. The definitions set out in G.S. 62-133.8 and 62-133.9 and Commission Rules R8-68 and R8-69 apply to this Mechanism. For purposes of this Mechanism, the definitions listed below also apply.

Changes in the terms and conditions of this Mechanism shall be applied prospectively only. Approved programs and measures shall continue to be subject to the terms and conditions that were in effect when they were approved with respect to the recovery of reasonable and prudent costs and net lost revenues. With respect to the recovery of Program Performance Incentives, approved programs and measures shall continue to be subject to the terms and conditions in effect in the vintage year that the measurement unit was installed.

The Mechanism may be adjusted where necessary to accommodate the specific characteristics of future DSM/EE programs.

__Definitions__

1. *Common costs* are costs that are not attributable to specific DSM or EE programs but are necessary to design, implement, and operate the programs collectively.

2. *Costs* include program costs, common costs, and, subject to Rule R8-69(b), costs also include the designated amounts dedicated for expenditure on efforts to promote general awareness of and education about EE and DSM activities, as well as research and development activities and the costs for pilot programs.

3. *Low Income Programs or Low Income Measures* are DSM or EE programs or measures provided specifically to low-income customers.

4. *Measure* means, with respect to EE, an "energy efficiency measure," as defined in G.S. 62-133.8(a)(4), that is new under G.S. 62-133.9(a) and refers to an

equipment, physical, or program change that results in less energy used to perform the same function. With respect to DSM, a measure refers to an activity, initiative, or program change that is new under G.S. 62-133.9(a) and is undertaken by DNCP or its customers to shift the timing of electricity use from peak to non-peak demand periods. DSM includes, but is not limited to, load management, electric system equipment and operating controls, direct load control, and interruptible load.

5. *Measurement unit* means the basic unit that is used to measure and track the (a) incurred costs; (b) net lost revenues; and (c) net savings for DSM or EE measures installed in each vintage year. A measurement unit may consist of an individual measure or bundles of measures. Measurement units shall be requested by DNCP and established by the Commission for each program in the program approval process, and shall be subject to modification by the Commission when appropriate. If measurement units have not been established for a particular program, the measurement units for that program shall be the individual measures, unless the Commission determines otherwise.

6. *Measurement unit's life* means the number of years that equipment associated with a measurement unit will operate if properly maintained or activities associated with the measurement unit will continue to be cost-effective, unless the Commission determines otherwise.

7. *Net found revenues* means any net increases in revenues resulting from any activity by DNCP's public utility operations that causes a customer to increase demand or energy consumption, whether or not that activity has been approved pursuant to Rule R8-68.

8. *Net lost revenues* means a payment to DNCP based on its revenue losses, net of marginal costs avoided at the time of the lost kilowatt-hour sale(s), or in the case of purchased power, in the applicable billing period, incurred by DNCP's public utility operations as the result of a new DSM or EE measure. Notwithstanding this definition, subject to review in future DSM/EE cost recovery proceedings and fuel and fuel-related cost proceedings, net lost revenues may be calculated based on the average retail non-fuel base rate revenues per kWh, over a reasonably determined time period, applicable to the customer class impacted by the measure, excluding the related customer charge component of those revenues, applied to the reduction in kWh sales resulting from the measure, less any avoided variable O&M expenses. When multiple customer classes are impacted by the DSM/EE measures, a weighted net lost revenue calculation may be employed. Net lost revenues will be reduced by any applicable net found revenues as set forth in paragraph 30. Program Performance Incentives shall not be considered in the calculation of net lost revenues.

9. *Program* means a collection of new DSM or EE measures with similar objectives, which have been consolidated for purposes of delivery, administration, and cost recovery, and which have been or will be adopted on or after January 1, 2007, including subsequent changes and modifications.

10. *Program costs* are costs that are attributable to specific DSM or EE programs and include all capital costs (including cost of capital and depreciation expenses), common costs, administrative costs, implementation costs, Evaluation, Measurement & Verification (EM&V) costs, incentive payments to program participants, and operating costs, net of any grants, tax credits, or other reductions in cost received by the utility from outside parties. Subject to

Rule R8-69(b), costs also include the designated amounts dedicated for expenditure on efforts to promote general awareness of and education about EE and DSM activities, as well as research and development activities and the costs for pilot programs.

11. *Program Performance Incentive* (PPI) means a payment to DNCP for adopting and implementing new EE or DSM measures, based on the sharing of savings achieved by those DSM and EE measures. PPI excludes net lost revenues.

12. *Total Resource Cost (TRC) test* means a cost-effectiveness test that measures the net costs of a DSM or EE program as a resource option based on the total costs of the program, including both the participants' costs and the utility's costs (excluding incentives paid by the utility to or on behalf of participants). The benefits for the TRC test are avoided supply costs, i.e., the reduction in transmission, distribution, generation, and capacity costs valued at marginal cost for the periods when there is a load reduction. The avoided supply costs shall be calculated using net program savings, i.e., savings net of changes in energy use that would have happened in the absence of the program. The costs for the TRC test are the net program costs incurred by the utility and the participants, and the increased supply costs for any periods in which load is increased. All costs of equipment, installation, operation and maintenance, removal of equipment (less salvage value), and administration, no matter who pays for them, are included in this test. Any tax credits are considered a reduction to costs in this test.

13. *Utility Cost Test* (UCT) means a cost-effectiveness test that measures the net costs of a DSM or EE program as a resource option based on the costs incurred by the utility (including incentive costs paid by the utility to or on behalf of participants) and excluding any net costs incurred by the participant. The benefits for the UCT are the avoided supply costs, i.e., the reduction in transmission, distribution, generation, and capacity costs valued at marginal cost for the periods when there is a load reduction. The avoided supply costs shall be calculated using net program savings, i.e., savings net of changes in energy use that would have happened in the absence of the program. The costs for the UCT are the net program costs incurred by the utility, the incentives paid to or on behalf of participants, and the increased supply costs for any periods in which load is increased. Utility costs include initial and annual costs, such as the cost of utility equipment, operation and maintenance, installation, program administration, and participant dropout and removal of equipment (less salvage value).

14. *Vintage year* means a prescribed calendar year in which a specific DSM or EE measure is installed for an individual participant or group of participants.

<u>Application for Approval of Programs</u>

15. In evaluating potential DSM/EE measures and programs for selection and implementation, DNCP will first perform a qualitative measure screening to ensure measures are:

a. Applicable to the DNCP service area demographics and climate.
b. Feasible for a utility DSM/EE program.

16. DNCP will then further screen EE and DSM measures for cost-effectiveness. With the exception of measures included in a Low Income Program, an EE or DSM measure with a TRC test result less than 1.0 will not be considered further, unless the measure can be bundled into an EE or DSM Program to enhance the overall cost-effectiveness of that program.

17. With the exception of Low Income Programs, all programs submitted for approval will meet the most restrictive cost benefit requirements in the jurisdictions which DNCP serves, but in no case will DNCP submit a program that has TRC test or UCT results less than 1.05.

18. DNCP will *contact* each party to its most recent DSM/EE cost recovery proceeding by March 1 of the following year and provide it with a list and description of programs and measures either currently being considered or planned for future consideration, and seek suggestions for additional programs and measures for consideration.

19. Nothing in this Mechanism relieves DNCP from its obligation to comply with Commission Rule R8-68 when filing for approval of DSM or EE measures or programs. As specifically required by Rule R8-68(c)(3), DNCP shall, in its filings for approval of measures and programs, describe in detail the industry-accepted methods to be used to collect and analyze data; measure and analyze program participation; and evaluate, measure, and verify estimated energy and peak demand savings. DNCP shall provide a schedule for reporting the results of this evaluation, measurement and verification (EM&V) process to the Commission. The EM&V process description should describe not only the methodologies used to produce the impact estimates utilized, but also, if appropriate, any methodologies DNCP considered and rejected. Additionally, if DNCP plans to use an independent third party for purposes of EM&V, DNCP shall identify the third party and include all third-party costs.

Cost Recovery

20. As provided in Rule R8-69 and G.S. 62-133.9(d), DNCP shall be allowed to recover, through the DSM/EE rider, all reasonable and prudent costs reasonably and appropriately estimated to be incurred in expenses during the current rate period for DSM and EE programs that have been approved by the Commission under Rule R8-68. As permitted by G.S. 62-133.9(d), any of the Stipulating Parties may propose a procedure for the deferral and amortization in future DSM/EE riders of all or a portion of DNCP's reasonable and prudent costs to the extent those costs are intended to produce future benefits.

21. The DSM/EE EMF rider shall reflect the difference between the reasonable and prudent costs incurred during the applicable test period and the revenues actually realized during such test period under the DSM/EE rider then in effect. The final allocation and assignment of

those costs to the North Carolina retail jurisdiction and retail customer classes shall be determined when costs are approved for inclusion in the DSM/EE EMF rider.

22. The cost and expense information filed by DNCP pursuant to Commission Rules R8-68(c) and R8-69(f) shall be categorized by measurement unit and vintage year.

23. In accordance with Commission Rule R8-69(b)(6), DNCP may implement deferral accounting for over- and under-recoveries of costs that are eligible for recovery through the annual DSM/EE rider. The balance in the deferral account, net of deferred income taxes, may accrue a return at the net-of-tax rate of return approved in DNCP's then most recent general rate case. The accrual of such return on any under-recovered or over-recovered balance approved for recovery or refund through a DSM/EE EMF rider shall cease as of the effective date of such rider, unless otherwise determined by the Commission.

24. In accordance with Commission Rule R8-69(b)(3), any over-recovery of DSM/EE costs ordered to be refunded through the DSM/EE EMF rider shall include interest at a rate to be determined by the Commission, not to exceed the maximum statutory rate. The beginning date for measurement of such interest shall be the effective date of the DSM/EE rider in each annual proceeding, unless otherwise determined by the Commission.

25. Beginning with the DSM/EE cost recovery filing in 2012, DNCP shall (a) perform biennial cost-effective test evaluations for each of its approved DSM and EE programs that has been implemented for at least 12 months, (b) perform biennial aggregated portfolio-level cost-effectiveness test evaluations for its approved DSM/EE programs (including common costs) that have been implemented for at least 12 months, and (c) include these cost-effectiveness test results in its DSM/EE rider application along with a discussion of whether those results indicate that any of the programs should be discontinued or modified.

Lost Revenues

26. Unless otherwise ordered by the Commission, when authorized pursuant to Rule R8-69(c), DNCP shall be permitted to recover, through the DSM/EE EMF riders, net lost revenues associated with the implementation of approved DSM and EE measurement units, subject to the restrictions set out below. The recovery of net lost revenues only through the DSM/EE EMF riders will be subject to continuing review for reasonableness.

27. The kWh sales reductions that result from an approved measurement unit installed in a given vintage year shall be eligible for use in calculating net lost revenues only for the first 36 months after the installation of the measurement unit. Thereafter, such kWh sales reductions will not be eligible for calculating net lost revenues. The actual recovery of net lost revenues associated with an approved measurement unit will begin no later than the commencement of the

final true-up of the PPI for the same measurement unit. Net lost revenues shall ultimately be based on kWh sales reductions verified by the EM&V process and approved by the Commission.

28. Programs or measures with the primary purpose of promoting 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. In order to recover net lost revenues associated with a pilot program or measure, DNCP 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 DNCP will implement an EM&V plan based on industry-accepted protocols for the program or measure. No pilot program or measure will be eligible for net lost revenue recovery unless it is ultimately proven to have been cost-effective.

29. Notwithstanding the allowance of 36 months' net lost revenues associated with eligible kWh sales reductions in paragraph 27 above, the kWh sales reductions that result from measurement units installed shall cease being eligible for use in calculating net lost revenues as of the effective date of (a) a Commission-approved alternative recovery mechanism, or (b) the implementation of new rates approved by the Commission in a general rate case or comparable proceeding to the extent the rates set in the general rate case or comparable proceeding are set to explicitly or implicitly recover the net lost revenues associated with those kWh sales reductions.

30. Total net lost revenues as measured for the 36-month period identified in paragraph 27 above shall be reduced by net found revenues that occur during the same 36-month period. DNCP shall closely monitor its utility activities to determine if they are causing a customer to increase demand or consumption, and shall identify and track all such activities, so that they may be evaluated by intervening parties and the Commission as potential net found revenues. Net found revenues shall be calculated based on the identifiable incremental retail non-fuel base rate revenue resulting from the applicable activity, less any incremental variable O&M expense. In the event that

incremental revenues are not identifiable through the EM&V process, then net found revenues shall be calculated based on the average retail non-fuel base rate revenues per kWh, over a reasonably determined time period, applicable to the customer class impacted by the activity, excluding the related customer charge component of those revenues, applied to the increase in kWh sales resulting from the activity, less any incremental variable O&M expenses. When multiple customer classes are impacted by the DSM/EE measures, a weighted net found revenue calculation may be employed.

Program Performance Incentive (PPI)

31. When authorized pursuant to Rule R8-69(c), DNCP shall be allowed to collect a PPI for each DSM or EE program approved and in effect during a given period, subject to the restrictions set out below.

32. Programs or measures with the primary purpose of promoting general awareness of and education about EE and DSM activities, as well as research and development activities, are ineligible to receive a PPI. Pilot programs or measures are also ineligible to receive a PPI.

33. With the exception of Low Income Programs or Low Income Measures, for any vintage year in which a program's or measure's TRC test result is less than 1.00, calculated using Commission-approved EM&V results, there shall be a rebuttable presumption that the PPI for that program or measure for the applicable vintage year is zero. DNCP shall be allowed an opportunity to rebut the presumption that PPI should be zero, by showing the impact of weather, decline in avoided costs, market forces, or other factors beyond DNCP's control.

34. The PPI shall be based on the net savings of each program or measure as calculated using the UCT, on a total system basis. The North Carolina retail jurisdictional and class portions of the system-basis net savings shall be determined in accordance with Section 3 of the Stipulation entered into by DNCP and the Public Staff in Docket No. E-22, Sub 464 (for purposes of the cost recovery proceeding filed in 2010), and by such method or methods found reasonable and appropriate by the Commission (for purposes of proceedings filed in 2011 and afterwards). The total of the PPIs for all programs or measures shall be added to DNCP's DSM/EE or DSM/EE EMF cost recovery riders, as appropriate.

35. In its annual filing pursuant to Rule R8-69(f), DNCP shall file an exhibit that indicates, for each program or measure for which it seeks or may seek a PPI, the annual projected and actual utility costs, participant costs, number of measurement units installed, per kW and kWh impacts for each measurement unit, and per kW and kWh avoided costs for each measurement unit, consistent with the UCT, related to the applicable vintage year installations that it requests or may request the Commission to approve. Upon its review, the Commission will make findings based on DNCP's annual filing for each program or measure for which an estimated or trued-up PPI is approved.

36. Unless the Commission determines otherwise in an annual DSM/EE rider proceeding, the amount of the PPI initially to be recovered for a given measurement unit and vintage year shall be equal to 8% for DSM programs and measures and 13% for EE programs and measures, multiplied by the estimated net savings calculated using the UCT. Estimated net savings shall be the present value of the sum of the annual net savings for measurement units projected to be installed specific to each program or measure, which shall be calculated by multiplying the number of measurement units projected to be installed in each vintage year by

the most current estimates of each year's per installation kW and kWh savings and by the most current estimates of each year's per kW and kWh avoided costs, then subtracting each year's estimated utility costs, and discounting the result to determine a net present value. In approving the initial PPI, the Commission will assume that projections will be achieved.

37. Unless the Commission determines otherwise in an annual DSM/EE rider proceeding, the initial PPI shall be converted into a stream of 10 levelized annual payments, accounting for and incorporating DNCP's overall weighted average net-of-tax rate of return approved in DNCP's most recent general rate case as the appropriate interest rate.

38. The per kW avoided capacity costs and the per kWh avoided energy costs used to calculate net savings for a vintage year shall be determined annually by DNCP using comparable methodologies to those used in the most recently approved biennial avoided cost proceeding (currently the Differential Revenue Requirements methodology). DNCP's assumptions used in these methodologies, as well as the methodologies, are subject to the Public Staff's review and acceptance at the time DNCP files its petition for annual cost recovery pursuant to Rule R8-69 and this Mechanism. Unless DNCP and the Public Staff agree otherwise, DNCP shall not be allowed to update its avoided capacity costs and avoided energy costs after filing its petition for its annual cost recovery proceeding pursuant to R8-69 and this Mechanism and prior to the Commission's order establishing the rider for that rate period for purposes of calculating the PPI.

39. When DNCP files for its annual cost recovery under Rule R8-69, it shall comply with the filing requirements of Rule R8-69(f)(1)(iii), reporting all interim EM&V data, even if not final, to assist the Commission and the Public Staff in their review and monitoring of the impacts of the DSM and EE measures.

40. DNCP bears the burden of proving all savings and costs included in calculating the PPI. As provided in Rule R8-68(c)(3)(iii), DNCP shall be responsible for the EM&V of energy and peak demand savings consistently with its EM&V plan.

41. The PPI shall be trued-up as follows:

a. The PPI shall be trued-up in the first annual DSM/EE rider proceeding following the completion and review of a program's or measure's EM&V analysis for any portion of an applicable test year. The true-up shall be

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based on approved measurement units and shall cover all applicable time periods from the time period covered by the measurement unit's previous EM&V analysis or, if no previous EM&V analysis has taken place, the date of program or measure approval.

b. The amount of the PPI ultimately to be recovered for a given program or measure and vintage year shall be based on the actual net savings derived from all measurement units specific to the program or measure. Actual net savings shall be the present value of the sum of the actualized annual net savings for measurement units projected to be installed specific to each program or measure, which shall be calculated by multiplying the number of actual installed measurement units in each vintage year by the verified per installation kW and kWh savings for each year and by the per kW and kWh avoided costs used for each year in calculating the initial PPI, then subtracting each year's actual utility costs, and discounting the result to determine a net present value.

42. The combined total of all components of the estimated or trued up performance incentive shall be incorporated into the DSM/EE rider or the DSM/EE EMF rider, as appropriate.

Other Provisions

43. Commercial customers with annual consumption of 1,000,000 kWh or greater in the billing months of the prior calendar year and all industrial customers, who implement or will implement alternative DSM/EE measures, may, consistent with Commission Rule R8-69(d), elect not to be subject to the DSM/EE rider and the DSM/EE EMF rider. For purposes of application of this option, a customer is defined to be a metered account billed under a single application of a Company rate tariff. For commercial accounts, once one account meets the opt-out eligibility requirement, all other accounts billed to the same entity with lesser annual usage located on the same or contiguous properties are also eligible to opt out of the DSM/EE rider and the DSM/EE EMF rider.

44. In its quarterly ES-1 Reports to the Commission, DNCP 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 revenue incentives, and costs. Additionally, DNCP shall prepare and present (a) supplementary schedules setting forth its North Carolina retail jurisdictional earnings excluding the effects of the PPI; (b) supplementary schedules setting forth its North Carolina retail jurisdictional earnings excluding the effects of the Company's EE and DSM programs; and (c) supplementary schedules setting forth earnings, including overall rates of return, returns on common equity, and margins over program costs actually realized from its EE and DSM programs in total and stated separately by program class (program classes are hereby defined to be (i) EE programs and (ii) DSM programs). Detailed workpapers shall be provided for each scenario described above. Such workpapers, at a minimum, shall clearly show actual revenues, expenses, taxes, operating income, rate

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base/investment, including components, and the applicable capitalization ratios and cost rates, including overall rate of return and return on common equity.

45. The Stipulating Parties shall review the terms and conditions of this Mechanism at least every three years and shall submit any proposed changes to the Commission for approval.

DOCKET NO. E-22, SUB 466

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 Commercial Distributed Generation Program	) ORDER DENYING) APPROVAL OF) PROGRAM

BY THE COMMISSION: On March 11, 2010, in its Order Opting Out of Retail Customer Participation in Wholesale Demand Response Programs issued in Docket No. E-22, Sub 418, the Commission required Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (Dominion), to file for approval appropriate demand response programs for its North Carolina retail customers as soon as possible and no later than September 1, 2010. In its order, the Commission concluded that, under North Carolina law and its traditional regulatory structure, Dominion's retail customers cannot participate in PJM's wholesale market through its demand response programs individually or through aggregation by a third party not regulated by the Commission. The Commission acknowledged, however, the significant role demand response can play in reducing peak demand, postponing the need for additional electric generating capacity, and, ultimately, reducing costs for all consumers.

On September 1, 2010, Dominion filed six demand-side management (DSM) programs for approval by the Commission pursuant to G.S. 62-133.9 and Rule R8-68, including, in the above-captioned docket, its proposed Commercial Distributed Generation (CDG) Program.[1] Under the proposed CDG Program, commercial and industrial customers would commit a minimum of 200 kW of backup generation for dispatch in response to load control events initiated by Dominion for up to 120 hours per year in exchange for an incentive payment. Dominion proposed to use a third-party vendor to implement the program, including dispatching the backup generation and providing unit monitoring, maintenance and operation services in order to facilitate participation in the CDG Program. Incentive payments for participation in the CDG Program would be paid by Dominion to the participating customer through the third-party vendor. While participating in the CDG Program, customers would not also be able to participate in Dominion's load curtailment rate (Large General Service – Curtailable).

The Attorney General filed notice of intervention On October 1, 2010, but took no position in this proceeding with regard to the application. On January 7, 2011, the Public Staff filed a response to Dominion's application, and on January 18, 2011, Dominion filed reply comments.

In the Public Staff's response, it raised issues related to Dominion's inclusion of a utility incentive and exclusion of certain common administrative costs in the Company's evaluation of

[1] By Orders issued February 22, 2011, the Commission approved the following five programs: Docket No. E-22, Sub 463, Residential Low Income Program; Docket No. E 22, Sub 465, Air Conditioner Cycling Program; Docket No. E-22, Sub 467, Commercial HVAC Upgrade Program; Docket No. E-22, Sub 468, Residential Lighting Program; and Docket No. E-22, Sub 469, Commercial Lighting Program.

the cost-effectiveness of the CDG Program. The Public Staff concluded that the CDG Program meets the definition of a new DSM program pursuant to G.S. 62-133.8(a)(2) and recommended that the Commission: (1) approve the CDG Program as a new DSM program; (2) hold that the third-party contractor would be acting as Dominion's agent as it dispatches standby generators during control events; (3) require Dominion to a file a tariff for the CDG Program; (4) require Dominion to file detailed information about the CDG Program annually, including an analysis of curtailment events; (5) require Dominion to ensure that all marketing materials and contracts indicate that the CDG Program is being offered by Dominion through the third-party contractor; and (6) require Dominion to ensure that the third-party contractor maintains comprehensive records and makes them available for review by the Commission and the Public Staff. The Public Staff further recommended that the Commission determine the appropriate recovery of actual program costs and utility incentives associated with the proposed CDG Program in the annual rider proceeding established pursuant to G.S. 62-133.9 and Rule R8-69.

In its reply comments, Dominion concurred in the recommendations made by the Public Staff, and clarified certain additional issues raised in the Public Staff's response. Dominion reasserted its request that the Commission: (1) approve the CDG Program as a new DSM program, including incorporating the recommendations of the Public Staff; (2) permit Dominion to file its evaluation, measurement and verification (EM&V) report in the Company's annual DSM/EE Rider proceeding on October 1 of each year; and, (3) if determined necessary by the Commission, convene a technical conference to address any issues raised by the CDG Program application as suggested by Public Staff.

On March 3, 2011, the Commission issued an Order Scheduling Oral Argument stating that its review of Dominion's application and the subsequent filings in this docket had raised questions and concerns about the CDG Program, including whether the proposed CDG Program meets the definition of a DSM program eligible for cost recovery under Dominion's proposed DSM/EE rider and whether the relationship between the third-party contractor and the retail customer constituted an unlawful retail sale of power by a non-public utility entity to a retail customer. The Commission posed a series of specific questions and directed Dominion and the Public Staff to respond to these questions at the oral argument.

On April 1, 2011, Dominion filed an amended program application to clarify the CDG Program's design and to amend certain aspects of the CDG Program to address concerns raised by the Commission and the recommendations made by the Public Staff.

The oral argument was held as scheduled on April 13, 2011. The Commission heard argument from Dominion and the Public Staff on Dominion's amended program application and the issues raised in the Commission's March 3 Order. Dominion and the Public Staff filed a Joint Proposed Order on May 24, 2011.

POSITIONS OF THE PARTIES

In its amended application, Dominion addressed the issues raised by the Commission regarding the role of the third-party contractor and whether the proposed CDG Program meets the definition of a DSM program. First, Dominion clarified that only customer-owned backup generation would be eligible to participate in the CDG Program, with customer-owned generation including backup generators either owned by the customer or that are subject to a lease that is used as a financing instrument to facilitate the purchase of such backup generation by the customer. Dominion also clarified the role of the third-party contractor, explaining that customers would participate in the CDG Program by entering into individual agreements with the third-party contractor to dispatch, monitor, maintain and operate the customer-owned generation when called upon by the Company during a load control event. Participation incentives under the CDG Program are required to be flowed through the third-party contractor to the participating customer. At least 80% of the monthly participation payment and 100% of the fuel and operations and maintenance payments will flow through to the customer in the form of a direct incentive payment or discount applied toward the service fee charged by the third-party contractor. The third-party contractor will agree not to make sales of metered electric energy to customers participating in the CDG Program.

Dominion further argued that the Commission should approve the CDG Program as a new DSM program because it previously approved an analogous program proposed by Duke Energy Carolinas, LLC (Duke). Specifically, under the standby generator program option of Duke's PowerShare Nonresidential Load Curtailment program, approved in 2009, customers agree to transfer a minimum of 200 kW of load from Duke's system to the customer's standby generator in response to system load curtailment events called by Duke. Similar to the proposed CDG Program, Dominion stated that Duke's PowerShare standby generator curtailment option provides load management through the use of backup generation to shift load from the Company's system to off-system generators during peak periods in exchange for an incentive. Thus, Dominion asserted that, as the CDG Program and PowerShare standby generator curtailment option operate to provide load management in a nearly identical manner, the Commission should apply the same statutory definition of DSM to the two programs and approve the CDG Program as a new DSM program.

DISCUSSION AND CONCLUSIONS

After careful consideration, the Commission finds good cause to deny approval of Dominion's proposed CDG Program. Dominion argues that the proposed CDG Program is nearly identical to the standby generator program option of Duke's Rider PS (NC), PowerShare Nonresidential Load Curtailment. The Commission, however, finds several significant differences that militate against approval of Dominion's program.

The standby generator program option of Duke's PowerShare program has its roots in the guaranteed generator response option of Duke's Rider SG (NC), Standby Generator Control. As Duke witnesses testified in seeking approval of its save-a-watt program in Docket No. E-7, Sub 831, of which PowerShare is a part, Rider SG has been offered by Duke for a number of years. In fact, Rider SG was initially approved in Docket No. E-7, Sub 270 by order dated May 19, 1981. The guaranteed generator response option was proposed and approved in January 1989 in Docket No. E-7, Sub 446. As noted in the orders and filings in those dockets, Rider SG was designed to provide a source of capacity through load reduction at any time Duke had capacity problems. In proposing the guaranteed generator response option, which added a monthly capacity credit to the existing energy credit, Duke stated that "[t]he addition of this new capacity credit should attract more customers with standby generators to commit to use them in a highly responsive manner when requested by the Company in order to reduce their load on the Company's generation system." The essence, then, of Duke's program was to take advantage of existing customer-owned backup generating capacity sitting idle during periods of extreme peak demand. By utilizing this otherwise unused existing capacity, Duke was able to avoid the construction of new capacity to meet its peak demand. Duke was also able to take advantage of this existing capacity without forcing customers to turn over operation and maintenance of their generation to a single contractor selected by the utility.

Dominion's CDG Program, in contrast, is not currently designed to take advantage of existing idle customer-owned generation. Rather, with the mandatory involvement of Dominion's third-party contractor, it is designed to incent the construction of new generation, albeit ostensibly by customers rather than the utility. Even so, the customers to be signed up under the program are merely passive participants and are simply agreeing for the third-party contractor to construct, operate and maintain the new generation at the customer's site. The program is structured to allow the third-party to provide the capital for construction of new generation funded by the monthly participant incentives proposed by Dominion.

As the Commission stated in its March 11, 2010 Order in Docket No. E-22, Sub 418, demand response programs can play a significant role in reducing peak demand and postponing the need for the construction of additional electric generating capacity. The proposed CDG Program, however, does not defer the construction of generation, but simply shifts the capital funding for such new generation. This program does not, as Duke's did, take advantage of existing customer-owned generation, but causes new customer-owned (and third-party financed) generation to be built. It appears to share more in common with a power purchase agreement for peaking power than a demand response or load curtailment program. As Duke's program demonstrates, Dominion could offer a cost-effective standby generator program without requiring customers to work with a single, designated third-party contractor. Without more flexibility for customer participants, Dominion's proposed program is not substantially similar to the standby generator program option of Duke's PowerShare program, has not been demonstrated as having the effect of deferring the construction of new electric generation, and, therefore, should not be approved. The Commission encourages Dominion to consider further modifications to its standby generation program and to refile the program, as well as any other cost-effective demand response programs, for Commission approval.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 14th day of September, 2011.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Chairman Edward S. Finley, Jr., dissenting. Commissioner Lucy T. Allen did not participate in this decision.

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DOCKET NO. E-22, SUB 466

CHAIRMAN EDWARD S. FINLEY, JR., DISSENTING: I respectfully dissent from the majority's decision in this docket denying approval of Dominion's Commercial Distributed Generation (CDG) Program. In my opinion, Dominion, in its April 1, 2011 amended program application, adequately addressed all of the issues raised by the Commission and the Public Staff, and the proposed new demand-side management (DSM) program should be approved.

As I read the majority opinion, the gist of the ruling is that Dominion's CDG Program is not a carbon copy of the standby generation option of the PowerShare program previously approved by the Commission in 2009 for Duke Energy Carolinas, LLC (Duke). While I find the differences between the Duke and Dominion programs immaterial, especially after Dominion's modifications, the appropriate issue before the Commission is whether the CDG Program satisfies the requirements of G.S. 62-133.8(a)(2). I determine that the CDG Program clearly qualifies and find nothing in the majority opinion to the contrary.

Dominion filed its CDG Program for approval in accordance with the Commission's March 11, 2010 Order in Docket No. E-22, Sub 418 directing the Company to file demand response programs for its North Carolina retail customers. The Commission has approved the remaining programs filed at that time, and it should also approve this DSM program, as recommended by the Public Staff.

In the amended program application, Dominion revised the program purpose section to more clearly address how the CDG Program operates and qualifies as DSM under G.S. 62-133.8(a)(2). By more efficiently using customer-owned generation to reduce the Company's load during system peak periods, the CDG Program will provide an effective form of load management, which achieves demand reductions and creates capacity and energy savings for Dominion's system. Dominion asserted that the CDG Program: (1) satisfies the definition of DSM set forth in G.S. 62-133.8(a)(2); (2) is consistent with the policy enacted by the General Assembly as part of Senate Bill 3 for utilities to consider the entire spectrum of demand-side options, including, but not limited to, conservation, load management, and EE programs; and (3) is nearly identical in all functional respects to the standby generation option of Duke's PowerShare program. Still, based on yet another set of distinctions that are not persuasive to me, the Commission rejects this program.

The majority attempts to distinguish Duke's PowerShare program from the distributed generation program proposed by Dominion by citing Dominion's use of a third-party vendor. I believe such a distinction is inappropriate, however, in light of the Commission's May 10, 2011 Order in Docket No. E-22, Sub 380A. In that Order, the Commission approved Dominion's request to amend its Code of Conduct to allow the Company to "engage the services of non-affiliated vendors and consultants to perform services related to implementation of these programs...." The programs cited included the distributed generation program before us in this proceeding. The Commission approved Dominion's request to amend its Code of Conduct without conditions. If the Commission had misgivings about the role of third-party vendors in implementing Dominion's DSM and energy efficiency (EE) programs, Dominion's request to amend its Code of Conduct provided an opportunity for the Commission to alert the Company by denying or conditioning its request.

Dominion addressed the Commission's concerns relating to the third-party contractor and potential unlawful retail sales by stating in the amended application that only customer-owned backup generation would be eligible to participate in the CDG Program. The amended program application and proposed program tariff defined customer-owned generation to include backup generators either owned by the customer or that are subject to a lease that is used as a financing instrument to facilitate the purchase of such backup generation facilities by the customer. The amended program application also clarified the role of the third-party implementation contractor, explaining that customers would participate in the CDG Program by entering into individual agreements with the third-party implementation contractor, subject to review and approval by the Company, to dispatch, monitor, maintain, and operate the customer-owned generation when called upon by the Company during a load control event. The amended program application also required a commitment by the third-party contractor in the general terms and conditions document not to make sales of metered electric energy to customers participating in the program. Based on these clarifications, Dominion asserts that there would not be any retail sale of power under the CDG Program in violation of North Carolina law.

Dominion explained during oral argument that the use of third-party vendors allows the Company to supervise the implementation of its portfolio of DSM and EE programs while taking advantage of the contractors' expertise, resources, operational experience, established supply chains, and technological infrastructure. In designing the CDG Program and the other five DSM and EE programs filed contemporaneously for approval on September 1, 2010, the Company determined that it would be cost-effective to use third-party vendors to implement the programs and to act as the primary interface with individual customers on behalf of Dominion. According to Dominion, the use of third-party vendors will maximize program penetration and provide customers with greater participation opportunities.

Dominion also clarified in the amended program application that participation incentives under the CDG Program are required to be flowed through the third-party contractor to the customer participating in the CDG Program. More specifically, at least eighty percent of the monthly participation payment will flow through to the customer in the form of a direct incentive payment or discount applied towards the service fee charged by the third-party contractor. The amended program application stated that customers are also compensated for fuel and associated costs of operating the backup generator during control events called by the Company such that the third-party contractor is obligated to flow through one hundred percent of the applicable fuel and operations and maintenance payments to the customer. The proposed tariff also explained how these payments would be calculated. The modifications Dominion made to the program lead me to the conclusion that the differences between the CDG Program and PowerShare are immaterial.

The majority asserts that Dominion's proposed program would cause new customer-owned generation to be built. The Public Staff raised that concern as well and suggested steps the Commission could take to address it. Specifically, on page 5 of its January 7, 2011 response to Dominion's program application, the Public Staff stated:

> ... processes should be established to enable [Dominion] and the Commission to monitor generator installation, in order to monitor and gain assurance that the incentive is not driving the decision to install the standby generators. Should this appear to be the case, changes in the Program ... may be required.

The Public Staff stated that the Commission should require Dominion to include various documentation in its annual DSM/EE cost recovery proceeding including "a report whether the operation of the [distributed generation] Program has caused an increase in the installation of standby generators." Instead of making this provision a condition of program approval, the majority opted to deny program approval.

By any industry recognized definition, and in full compliance with North Carolina statutory requirements, this program easily qualifies as a traditional demand response program. When demand from its customers is high, Dominion has the ability to curtail or interrupt service to customers subscribing to the program. Dominion is thereby able to avoid running high operating cost generation or purchasing expensive power on the grid, which utilizes capacity on the Dominion transmission system. The subscribing customer must resort to off-grid generation to supplant what Dominion otherwise would have supplied. Based on Dominion's Integrated Resource Plan, even after compensating the subscribing customer under the proposed program, Dominion and its non-subscribing customers benefit financially because other alternatives are more costly. The program is a win-win-win. No party to the docket opposes it.

While Senate Bill 3 makes an otherwise unusual distinction between energy efficiency and demand response, suggesting that there must be an actual shift of demand from one time to another to qualify for demand response, the sole purpose of this distinction is to limit the type of program that qualifies for compliance with the Renewable Energy and Energy Efficiency Portfolio Standard (REPS) requirements. Overly technical interpretation of this distinction to disqualify for Senate Bill 3 treatment what qualifies as a demand response program under any commonly understood meaning of the term exalts form over substance. This program enables the electric public utility that the Commission regulates to shave its peak, the essential objective of demand response.

For the reasons argued by Dominion and the Public Staff, I would find that the amended program application resolves the concerns initially raised by the Commission and would approve the proposed CDG Program.

\s\ Edward S. Finley, Jr.
Chairman Edward S. Finley, Jr.

DOCKET NO. E-22, SUB 473

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 RIDER AND REQUIRING CUSTOMER NOTICE

HEARD: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina on Wednesday, November 9, 2011, at 10:29 a.m.

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

APPEARANCES:

For Dominion North Carolina Power:

Robert W. Kaylor, Law Office of Robert W. Kaylor, P.A., 3700 Glenwood Avenue, Suite 330, Raleigh, North Carolina 27612

Vishwa B. Link, McGuireWoods, LLP, One James Center, 901 East Cary Street, Richmond, Virginia 23219

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: G.S. 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) 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 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.

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. 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.

Docket No. E-22, Sub 473

On July 15, 2011, Virginia Electric and Power Company d/b/a Dominion North Carolina Power (DNCP or Company) filed a motion for approval to submit its annual DSM/EE cost recovery rider on August 26, 2011, as provided for in Rule R8-69(e)(2). This motion was approved by Order of the Commission issued on July 21, 2011.

On August 26, 2011, DNCP filed an application for approval of cost recovery for demand-side management and energy efficiency measures, together with the prefiled direct testimony and exhibits of its witnesses Brandon E. Stites, Ripley C. Newcomb, Michael J. Jesensky, David L. Turner, Rick L. Propst, Paul B. Haynes, and Kurt W. Swanson, for the approval of a DSM/EE rider to recover the Company's reasonable and prudent forecasted DSM/EE expenses, capital costs, certain indirect common costs, taxes, net lost revenues, and a Program Performance Incentive (PPI) for implementation of its DSM/EE programs. DNCP's application requested a total annual revenue requirement of $2,023,332 to be recovered through its updated DSM/EE rider, Rider C, effective on and after January 1, 2012. The net effect of this request would increase the monthly bill of a typical residential customer using 1,000 kilowatt-hours of electricity by $0.92 or approximately 1.0%, based on the rates in effect at the time of the filing.

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

On September 8, 2011, the Commission issued its Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice. Pursuant to such Order, deadlines were established for the filing of petitions to intervene, intervenor testimony and exhibits, and Company rebuttal testimony and exhibits; and a public hearing was scheduled to be held in Raleigh, North Carolina on Wednesday, November 9, 2011.

On September 29, 2011, the Public Staff filed a motion for extensions of time seeking to modify the dates for intervenor testimony and the Company's rebuttal testimony as well as to require all parties to serve testimony and exhibits via email on the date such testimony is filed. Such motion was supported by the Company, and was approved by Order of the Commission on October 4, 2011.

On October 10, 2011, DNCP filed a motion for limited admission to practice for Vishwa B. Link, counsel for the Company. On October 12, 2011, the Commission issued an Order Granting Motion for Admission Pro Hac Vice.

On October 24, 2011, the Public Staff filed the affidavit of Jack L. Floyd, Electric Engineer, Electric Division and the testimony and exhibit of Michael C. Maness, Assistant Director, Accounting Division.

On November 2, 2011, DNCP filed its affidavit of publication indicating that the Company had provided notice in newspapers of general circulation as required by the Commission's September 8, 2011 Order.

On November 4, 2011, the Company prefiled the rebuttal testimony of its witnesses Brandon E. Stites, Michael J. Jesensky, David L. Turner, Rick L. Propst, Paul B. Haynes, and Kurt W. Swanson in response to the testimony filed by the Public Staff. Also on November 4, 2011, the Company filed an Addendum to Agreement and Stipulation of Settlement (Addendum) agreed to and executed by the Company and the Public Staff (the Stipulating Parties) on November 3, 2011, which settled all contested issues in this proceeding. In such Addendum, the Stipulating Parties agreed to waive cross-examination of each other's witnesses. On November 7, 2011, the Commission approved the Stipulating Parties' verbal motion to excuse all witnesses from attending the hearing on November 9, 2011..

The matter came on for evidentiary hearing as scheduled on November 9, 2011. No public witnesses appeared. The Applicant stated that it agreed with the recommendations of the Public Staff; consequently DNCP and the Public Staff agreed to accept all prefiled testimony, exhibits, and affidavits into the record and to waive cross-examination of all witnesses. The prefiled direct and rebuttal testimony of Brandon E. Stites, direct testimony and exhibits of Ripley C. Newcomb, direct and rebuttal testimony and exhibits of Michael J. Jesensky, direct and rebuttal testimony and exhibits of David L. Turner, direct and rebuttal testimony and exhibits of Rick L. Propst, direct and rebuttal testimony and exhibits of Paul B. Haynes, and direct and rebuttal testimony and exhibits of Kurt W. Swanson were received into evidence. The direct testimony and exhibits of Public Staff witness Maness as well as the affidavit of Jack L. Floyd, as corrected, were entered into evidence on behalf of the Public Staff. The Company and the Public Staff also entered the Addendum into the record.

On November 30, 2011, DNCP and the Public Staff jointly filed a Proposed Order. The Addendum was included as Appendix A and a proposed Notice to Customers was included as Appendix B to the Joint Proposed Order.

<u>Other Pertinent Information - Docket Nos. E-22, Subs 464 and 466</u>

On September 14, 2011, the Commission issued its Order Denying Approval of Program in Docket No. E-22, Sub 466, denying approval of the Company's proposed Commercial Distributed Generation (CDG) Program. 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 Compliance Filing (Sub 464 Cost Recovery Order). In the Sub 464 Cost Recovery Order, the Commission approved the Agreement and Stipulation of Settlement (Stipulation) between the Public Staff and the Company filed on March 2, 2011, as well as the Cost Recovery and Incentive Mechanism attached as Stipulation Exhibit 1 to the Stipulation (Mechanism). The Commission's approval of the Stipulation was subject to a minor modification to the effective date of Rider C to allow the Company to put its approved Rider C rates into effect on November 1, 2011, subject to future true-up in DNCP's 2012 annual DSM/EE rider proceeding. The Sub 464 Cost Recovery Order also held that as the Commission had denied approval of the CDG Program, it was not appropriate for the Company to recover costs associated with this proposed program through Rider C. The Commission directed the Company to file revised allocations, if any, and supporting schedules in the current proceeding based on the Commission's denial of the CDG Program.

On October 21, 2011, in Docket No. E-22, Sub 464, the Company filed a draft customer notice, Rider C, and updated tariff table of contents incorporating Rider C, which the Commission approved by Order issued on October 24, 2011, in that same docket.

On November 4, 2011, the Company also filed a copy of the Addendum in Docket No. E-22, Sub 464, for reference purposes as the Stipulation and Mechanism had been filed and approved in that proceeding.

Based upon DNCP's application, the Stipulation (March 2, 2011), the Mechanism (March 2, 2011), the Addendum (November 4, 2011), 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. DNCP is a public utility operating in the State of North Carolina as Dominion North Carolina Power and 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. DNCP is lawfully before this Commission based upon its application filed pursuant to G.S. 62-133.9 and Commission Rule R8-69.

2. The test period for the purposes of this proceeding is the 12-month period July 1, 2010 through June 30, 2011.

3. The rate period for purposes of this proceeding is the 12-month period January 1, 2012 through December 31, 2012.

4. DNCP has requested the recovery of costs and incentives related to the following approved DSM/EE programs: (a) Low Income Program; (b) Air Conditioning Cycling Program; (c) Commercial HVAC Upgrade Program; (d) Residential Lighting Program; and (e) Commercial Lighting Program. DNCP has appropriately revised its request to exclude costs associated with the Company's CDG Program, which was denied approval, and has provided revised cost allocations as required by the Sub 464 Cost Recovery Order.

5. Recovery of the Company's DSM/EE costs is 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 Sub 464 Cost Recovery Order. The Addendum filed by the Company and the Public Staff on November 4, 2011, in this proceeding is reasonable and appropriate, and

should be approved and fully incorporated into the Stipulation for purposes of this and future DNCP DSM/EE proceedings.

6. Recovery of the Company's incremental common costs not directly related to specific DSM or EE programs, as well as projected net lost revenues and a utility incentive in the form of a PPI, is reasonable and consistent with the Stipulation and Mechanism.

7. It is appropriate for DNCP to recover in its DSM/EE rider the estimates of reasonable and prudent costs related to its approved DSM and EE programs, incremental common costs, and utility incentives, as allowed for in the Stipulation and Mechanism, subject to review and true-up during future annual rider proceedings. The reasonable and appropriate estimate of DNCP's North Carolina retail rate period DSM/EE revenue requirement, incorporating these components, is $1,925,860 (excluding gross receipts tax (GRT)).

8. Rider C, as proposed by the Company in its rebuttal testimony and exhibits filed on November 4, 2011, is reasonable and appropriate, and consists of the following customer class billing factors (including GRT): Residential – 0.086 ¢/kWh; Small General Service and Public Authority – 0.040 ¢/kWh; Large General Service – 0.038 ¢/kWh; 6VP[1] – 0.041 ¢/kWh; NS[2] – 0.000 ¢/kWh; Outdoor Lighting – 0.000 ¢/kWh; and Traffic Lighting – 0.000 ¢/kWh. The net effect of updated Rider C, as proposed in the Company's rebuttal testimony, using current base and fuel rates would increase the monthly bill of a typical residential customer using 1,000 kilowatt-hours of electricity by $0.33. It is reasonable and appropriate for Rider C to become effective for usage on and after January 1, 2012.

9. In accordance with Paragraph 2.C. of the Stipulation, it is reasonable and appropriate for DNCP to file its initial EMF in its 2012 DSM/EE cost recovery proceeding. As provided in the Commission's Sub 464 Cost Recovery Order and in accordance with the terms of the Mechanism, it is reasonable and appropriate for DNCP to use deferral accounting to recover any under- or over-recoveries of reasonably incurred costs that the Company intends to recover through such initial EMF.

10. It is reasonable and appropriate for the Company to file its evaluation, measurement and verification (EM&V) reports on or before April 1 of each year. Such reports should include sufficient information and an analysis of the gross and net savings and costs of the programs so that the Public Staff and the Commission may fully evaluate net-to-gross adjustments made by DNCP to determine the actual savings for each DSM or EE program.

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[1] Large General Service Variable Pricing.

[2] Applicable only to electric service at Nucor Corporation's steel manufacturing and recycling facility located in Hertford County, North Carolina.

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

These findings of fact are essentially informational, procedural, and jurisdictional in nature and are uncontroverted. The test period and rate period proposed by DNCP and agreed to by the Public Staff are consistent with Commission Rule R8-69.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The evidence for this finding of fact is contained in DNCP's application; the testimony of DNCP witnesses Stites, Turner, and Haynes; the affidavit of Public Staff witness Floyd and the testimony and exhibits of Public Staff witness Maness; and in various Commission orders.

In direct testimony filed on August 26, 2011, DNCP witness Stites testified that DNCP seeks cost recovery and incentives pursuant to Commission Rule R8-69 and G.S. 62-133.9 for the Company's six DSM/EE programs. This included the five programs approved by the Commission on February 22, 2011, in Docket Nos. E-22, Subs 463, 465, 467, 468, and 469, as well as the Company's CDG Program, which was pending before the Commission in Docket E-22, Sub 466, as of the date the current application was filed in Docket No. E-22, Sub 473. In direct testimony filed with its current application, DNCP witness Turner provided evidence regarding the estimated system-level program costs of the six DSM/EE programs, as well as the system-level common costs associated with implementing those programs. According to witness Turner, "program costs" are those costs which are directly attributable to individual programs, while "common costs" are those costs associated with the overall effort of designing, implementing, and operating the DSM/EE programs, but are not directly attributable to any individual program.

On September 14, 2011, the Commission issued an Order in Docket No. E-22, Sub 466, denying approval of the Company's CDG Program. The Commission subsequently issued its Sub 464 Cost Recovery Order on October 14, 2011, which stated that recovery of costs associated with the CDG Program was not appropriate through Rider C, and directed the Company to file revised allocations and supporting schedules based upon the Commission's denial of the CDG Program.

Public Staff witness Floyd asserted in his affidavit that costs related to the CDG Program were ineligible for recovery through Rider C, and that the Company had provided revised exhibits to the Public Staff in discovery excluding the costs associated with the CDG Program. Using these revised exhibits, Public Staff witness Maness updated the Company's revenue requirement and rates to reflect denial of the CDG Program, among certain other adjustments. In his rebuttal testimony, DNCP witness Stites asserted that the Company has revised its request in this case to remove the costs of the CDG Program, has agreed with the adjustments proposed by witness Maness, and has accepted and supported the schedules filed by witness Maness. Witness Haynes verified that witness Maness's testimony and schedules appropriately reflected elimination of costs associated with the CDG Program and reallocation of the Company's common costs, as directed by the Commission in the Sub 464 Cost Recovery Order. Witnesses Stites and Haynes requested that the Commission approve rates for updated Rider C, subject to true up in DNCP's 2012 annual DSM/EE rider proceeding,[1] based upon witness Maness's schedules, as discussed further hereinbelow.

The Commission finds that witness Maness's schedules, as verified by the Company, appropriately remove the costs associated with the CDG Program from the Company's request for cost recovery in this proceeding. The Commission is of the opinion that DNCP's estimated rate period DSM/EE revenue requirement, as incorporated into witness Maness's schedules, appears to be reasonable and prudent, subject to review and true-up during DNCP's future DSM/EE rider proceedings. As discussed elsewhere in this Order, the Commission finds and concludes that recovery of the revenue requirement set forth in witness Maness's testimony and schedules is reasonable and appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence for this finding of fact is contained in the testimony and exhibits of DNCP witnesses Stites, Turner, Propst, Haynes, and Swanson; the testimony and exhibits of Public Staff witness Maness; and in the Sub 464 Cost Recovery Order.

The Company's application, filed August 26, 2011, was developed and filed in conformance with the provisions of the Stipulation and Mechanism, which was subsequently approved by the Commission in its Sub 464 Cost Recovery Order. Public Staff witness Maness determined certain adjustments to the calculation of the Company's revenue requirement and rates were necessary to comply with the provisions of the Stipulation and Mechanism, as interpreted by the Public Staff. Specifically, in addition to incorporating the removal of the costs associated with the CDG Program and supporting a separate jurisdictional allocation factor proposal, witness Maness's testimony asserted that three additional adjustments related to (1) the cost of capital used to calculate the PPI; (2) the factor used to allocate the North Carolina retail revenue requirement to non-residential customer classes; and (3) the allocation of common costs to DSM/EE programs were necessary to conform the Company's application to the terms of the Stipulation and Mechanism.

In the Company's rebuttal testimony, witness Stites asserted that the Company concurred with those three adjustments proposed by witness Maness. In particular, Company witness Turner concurred with witness Maness's proposed adjustment to the cost of capital used to calculate the PPI pursuant to Paragraph No. 37 of the Mechanism, while witness Haynes concurred with witness Maness's adjustments to the allocation of common costs pursuant to Paragraph No. 3.A., and to the class allocation factors pursuant to Paragraph No. 3.C. of the Stipulation, respectively.

Witness Maness also proposed an additional adjustment to revise the jurisdictional allocation factors for DSM/EE program costs proposed by witness Haynes in his direct testimony. Pursuant to Paragraph No. 3.B. of the Stipulation, the Company and the Public Staff

[1] Due to the relationship between test periods and rate periods, the true-up of rates approved in this proceeding will actually be accomplished through the DSM/EE EMFs that may be subsequently approved in both the 2012 and 2013 cost recovery proceedings.

had agreed to a jurisdictional allocation methodology for purposes of the 2010 DSM/EE cost recovery proceeding only, and committed to work together to develop a reasonable jurisdictional allocation methodology to present to the Commission in this case. As noted in the direct testimony of witness Haynes, the Company and the Public Staff met twice in an attempt to reach agreement on the appropriate jurisdictional allocation methodology for system-level DSM/EE program costs. However, as of the date the most recent application was filed, no agreement had been reached and the Company filed its individual recommendation to assign system-level DSM/EE program costs to the North Carolina jurisdiction based upon relative participation levels that produce demand and energy reductions in the jurisdiction. The rationale for this assignment approach was extensively addressed in witness Haynes' direct testimony. Witness Maness's testimony presented the Public Staff's view that allocation of system-level DSM/EE program costs by appropriately adjusted peak demand and energy allocation factors, similar to the approach set forth in Paragraph No. 3.B. of the Stipulation, was the appropriate methodology to allocate costs between the Company's respective jurisdictions.

On November 4, 2011, the Company filed the proposed Addendum resolving the disagreement between the Company and the Public Staff regarding the appropriate jurisdictional allocation methodology to be used in this and in future DSM/EE rider proceedings. As explained by witness Haynes, the Addendum accepts the jurisdictional allocation approach proposed by witness Maness, subject to future review for reasonableness by the Stipulating Parties and the Commission pursuant to Paragraph No. 2.E. of the Stipulation and certain contingency provisions addressing potential future limitations on DSM/EE program participation in the Company's Virginia jurisdiction that could impact the Company's peak demand and energy allocation factors, thereby impacting the Company's ability to recover its total system costs. If such enumerated circumstances were to confront the Company in the future, the Addendum provides a process whereby the Company and the Public Staff can meet and attempt to resolve such issues through potential adjustment to the Company's North Carolina retail jurisdictional allocation factors in a subsequent annual DSM/EE cost recovery proceeding. The Addendum also provides that the agreement on jurisdictional allocation methodology is applicable only to DNCP's current and future DSM/EE cost recovery proceedings and does not apply to or affect either parties' ability to advocate for jurisdictional assignment or allocation of the costs and benefits of DSM/EE program costs in any other type of rate proceeding.

The Commission finds and concludes that the adjustments proposed by witness Maness related to (1) the cost of capital used to calculate the PPI; (2) the factor used to allocate the North Carolina retail revenue requirement to non-residential customer classes; and (3) the allocation of common costs to DSM/EE programs, which have been agreed to by the Company, appropriately apply the provisions of the Stipulation and Mechanism approved in the Sub 464 Cost Recovery Order. The Commission is of the opinion that the Addendum presents a reasonable and appropriate methodology to allocate system-level DSM/EE program costs between the Company's respective retail jurisdictions and should be approved and fully incorporated into the Stipulation.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence for this finding of fact is contained in the testimony and exhibits of DNCP witnesses Stites, Newcomb, Jesensky, Turner, and Haynes; the affidavit of Public Staff witness Floyd; and the testimony of Public Staff witness Maness.

The Company's application requests recovery of common costs as described in the testimony of Company witness Turner. While witness Floyd did not challenge recovery of any of the Company's common costs, he requested that the Company provide more detailed information regarding its common costs associated with activities to communicate, promote, and educate customers on DSM and EE, such as costs related to advertising, community outreach, web-based information, and customer education. Witness Floyd also requested that the Company provide additional details and include specific metrics in future DSM/EE rider proceedings that support the reasonableness and effectiveness of such common costs. In his rebuttal testimony, witness Turner explained that details on the Company's event sponsorship and consumer education and awareness costs were provided in his Schedule 3, and that the Company could provide additional details in future cases further describing these costs as well as providing information that supports the productivity of DNCP's event sponsorship and consumer education and awareness efforts.

The Company also requested approval of utility incentives in the form of an estimated PPI and the recovery of estimated net lost revenues, as provided for in the Stipulation and Mechanism. Subject to Public Staff witness Maness's adjustment to the cost of capital used by the Company to calculate the PPI as discussed above, witness Maness agreed that recovery of the PPI was reasonable and appropriate under the Stipulation and Mechanism, and he provided a calculation of the PPI in his Schedule 4. Witness Maness's calculation of projected net lost revenues presented in his Schedule 3 was also consistent with the approach proposed in the direct testimony of Company witness Jesensky and included in witness Haynes's Schedule 3. Witness Jesensky testified that this approach allows for timely recovery of net lost revenues and appropriately matches the period of benefit with the period of recovery.

The Company's common costs and utility incentives in the form of net lost revenues and a PPI, as set out in witness Maness's Schedules 3, 4, 5, and 5-1 and agreed to by the Company in rebuttal, are reasonable. The Commission finds and concludes that the Company's PPI, projected net lost revenues, and common costs as set forth in witness Maness's Schedules 3, 4, 5, and 5-1 comply with the provisions of the Stipulation and Mechanism, and should be approved for recovery, subject to true up, as part of the Company's revenue requirement in the present proceeding.

Further, the Commission finds and concludes that additional details on the Company's event sponsorship and consumer education and awareness costs would assist the Public Staff and the Commission in evaluating the reasonableness of these costs in future cases; therefore, the Company should provide additional information in its future DSM/EE rider applications further describing these costs and the volume of activity resulting from DNCP's event sponsorship and consumer education and awareness efforts.

ELECTRIC – RATE SCHEDULES/RIDERS/SERVICE RULES AND REGULATIONS

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 7 THROUGH 9

The evidence for these findings of fact is contained in the testimony and exhibits of DNCP witnesses Stites, Newcomb, Jesensky, Turner, Propst, Haynes, and Swanson; and the testimony and exhibits of Public Staff witness Maness.

Public Staff witness Maness testified that the Public Staff's review of DNCP's filing focused on whether the Company's proposed DSM/EE billing factors were calculated in accordance with the Stipulation and Mechanism, and otherwise adhered to sound ratemaking concepts and principles. Subject to the adjustments previously discussed hereinbefore, witness Maness stated that the Public Staff is of the opinion that the Company has calculated the Rider C billing factors in a manner consistent with G.S. 62-133.9, Commission Rule R8-69, and the Stipulation and Mechanism as approved by the Commission. Witness Maness proposed a revised revenue requirement and billing factors that incorporated witness Maness's recommended adjustments. While the Public Staff found a total revenue requirement of $2,120,721 (excluding GRT) to be reasonable, the Public Staff's billing factors for the SGS, LGS, and 6VP customer classes were higher than those proposed by the Company, and, therefore, the Public Staff recommended that the residential billing factor proposed by the Public Staff and the SGS, LGS, and 6VP billing factors proposed by the Company be approved.

In rebuttal testimony, Company witness Stites accepted the revised revenue requirement and billing factors proposed by the Public Staff and requested that the Commission approve the residential billing factor proposed by the Public Staff and the SGS, LGS, and 6VP billing factors proposed by the Company, subject to true up through the Company's initial DSM/EE EMF to be filed in its 2012 DSM/EE cost recovery proceeding.[1] Further, Company witness Swanson explained that the net effect of the Public Staff's recommendation results in a total Rider C revenue requirement in the amount of $1,925,860 (excluding GRT), which is less than the amount found reasonable by the Public Staff as well as the revenue requirement proposed in the Company's application. To address a potential under-recovery of the Company's DSM/EE costs, Company witness Propst asserted that in accordance with Commission Rule R8-69(b)(6) and Paragraph No. 23 of the Mechanism, the Company will employ deferral accounting for any over- or under-recoveries of costs that are eligible for recovery through the annual DSM/EE rider. Further, he explained that the Company will accrue a return on the deferral account balances in accordance with Paragraph No. 23 of the Mechanism. Witness Propst also noted that the Company has discussed this approach with the Public Staff and the Public Staff has indicated that this cost recovery approach is consistent with the Stipulation and Mechanism.

Witness Swanson testified and proposed as presented on Company Exhibit KWS-1, Rebuttal Schedule 1, Page 1 of 1, in accordance with the recommendations of the Public Staff and consistent with application of the Stipulation and Mechanism, the following customer class billing factors (including GRT) be put into effect: Residential – 0.086 ¢/kWh; Small General Service and Public Authority – 0.040 ¢/kWh; Large General Service – 0.038 ¢/kWh; 6VP – 0.041 ¢/kWh; NS – 0.000 ¢/kWh; Outdoor Lighting – 0.000 ¢/kWh; and Traffic Lighting –

[1] See Footnote 1.

0.000 ¢/kWh. The net effect of updated Rider C, as proposed in the Company's rebuttal testimony would increase the monthly bill of a typical residential customer using 1,000 kilowatt-hours of electricity by $0.33 or approximately 0.3%, based on the rates in effect at December 1, 2011.

The Commission finds and concludes that the Company's revenue requirement, as calculated by witness Maness, is reasonable, and that the billing factors, as proposed by the Company and the Public Staff, are appropriate to recover the Company's estimated DSM/EE revenue requirement during the 2012 rate period. The Commission observes that Rule R8-69(b)(6) and Paragraph No. 23 of the Mechanism allow the Company to employ deferral accounting for any over- or under-recoveries of costs eligible for recovery through the annual DSM/EE rider, and to recover any such under-recoveries through the Company's initial DSM/EE EMF to be filed in future cost recovery proceedings. In the interim, Paragraph No. 23 of the Mechanism also allows the Company to accrue a return on the deferral account balances. The Commission finds and concludes that Rider C should become effective for usage on and after January 1, 2012.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The evidence for this finding of fact is contained in the testimony of DNCP witness Jesensky and the affidavit of Public Staff witness Floyd; and in various Commission orders.

Company witness Jesensky testified that the Commission's Orders approving the Company's five DSM/EE programs directed the Company to file EM&V reports as part of its annual DSM/EE cost recovery proceedings commencing October 1, 2012. Witness Jesensky stated that the Company was proposing, as part of this proceeding and similarly in Virginia, to file EM&V Reports annually on April 1 starting in 2012. Each year's annual April 1 EM&V Report would include EM&V data from program inception through the end of the previous calendar year. Witness Floyd stated in his affidavit that he has reviewed two of the Company's EM&V reports filed with the Virginia State Corporation Commission that address the five programs approved in both jurisdictions. Witness Floyd asserted that DNCP's EM&V consultant intends to include more end-use data, analysis, and modeling as the programs mature to gain a better understanding of actual program savings, but, at this time, it is too early to make definitive recommendations based on the findings in the reports. Witness Floyd's affidavit, as corrected, recommended that the Commission approve the Company's request to file future EM&V reports on April 1 rather than October 1, as is currently required by the Commission's program approval orders. Witness Floyd also recommended that the Company's EM&V report include sufficient information and an analysis of the gross and net savings and costs of the programs so that the Commission may fully evaluate net-to-gross adjustments made by DNCP to determine the actual savings for each DSM or EE program. In his rebuttal testimony, witness Jesensky stated that the Company is planning to examine net-to-gross adjustments that are pertinent to the individual DSM or EE programs, such as free ridership, in-service rates, and realization rates, and will include such analysis in future EM&V reports.

Based upon the foregoing, the Commission finds and concludes that revising the Company's annual EM&V reporting cycle to April 1 of each year is reasonable. The

Commission is of the opinion that the Company's EM&V report should include sufficient information and an analysis of the gross and net savings and costs of the programs that will sufficiently allow the Commission and the Public Staff to be able to fully evaluate net-to-gross adjustments made by DNCP to determine the actual savings for each DSM or EE program.

IT IS, THEREFORE, ORDERED as follows:

1. That the Addendum to Agreement and Stipulation of Settlement entered into by DNCP and the Public Staff on November 3, 2011, and filed by DNCP on November 4, 2011, attached hereto as Appendix A, is hereby approved.

2. That the appropriate customer class billing factors (including GRT) that shall be incorporated in the Company's annual DSM/EE rider, updated Rider C, to become effective on and after January 1, 2012, are as follows: Residential – 0.086 ¢/kWh; Small General Service and Public Authority – 0.040 ¢/kWh; Large General Service – 0.038 ¢/kWh; 6VP – 0.041 ¢/kWh; NS – 0.000 ¢/kWh; Outdoor Lighting – 0.000 ¢/kWh; and Traffic Lighting – 0.000 ¢/kWh.

3. That the Notice to Customers attached hereto as Appendix B is appropriate and is hereby approved. Such Notice will appropriately provide notice of the rate changes ordered by the Commission in both this proceeding and in Docket No. E-22, Sub 474.[1]

4. That DNCP shall provide, in future DSM/EE rider applications, a listing of the Company's event sponsorship and consumer education and awareness initiatives during the relevant test period.

5. That DNCP shall revise its annual EM&V reporting cycle to April 1 of each year. Such annual EM&V reports shall include sufficient information and an analysis of the gross and net savings and costs of the programs such that the Public Staff and the Commission will be able to fully evaluate net-to-gross adjustments made by DNCP to determine the actual savings for each DSM or EE program.

ISSUED BY ORDER OF THE COMMISSION.
This the 13th day of December, 2011.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

fh121211.01

[1] Application by DNCP for a fuel charge adjustment pursuant to G.S. 62-133.2 and Commission Rule R8-55.

APPENDIX A
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STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-22, SUB 464
DOCKET NO. E-22, SUB 473

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
Application by Virginia Electric and Power	)	
Company, d/b/a Dominion North Carolina Power	)	ADDENDUM TO AGREEMENT
for Approval of Demand-Side Management and	)	AND STIPULATION OF
Energy Efficiency Cost Recovery Rider Pursuant to	)	SETTLEMENT
G.S. 62-133.9 and Commission Rule R8-69	)	

Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (DNCP or Company) and the Public Staff, collectively referred to as the Stipulating Parties, through counsel and pursuant to G.S. 62-69, respectfully submit the following addendum to the Agreement and Stipulation of Settlement as approved in the North Carolina Utilities Commission's (Commission or NCUC) Order Approving Agreement and Stipulation of Settlement, Approving DSM/EE Rider, and Requiring Compliance Filing in Docket No. E-22, Sub 464 (Stipulation) for consideration by the Commission. The Stipulating Parties hereby agree and stipulate as follows:

The Stipulating Parties have agreed to the following language as an addendum to the Stipulation (Addendum Language). The Stipulating Parties intend for this Addendum Language to be fully incorporated with and subject to the provisions of the Stipulation as a supplement to Paragraph No. 3.B of the Stipulation. In addition, the Stipulating Parties shall review the terms and conditions of the Addendum Language contemporaneously with the Parties' review of the Stipulation and Mechanism pursuant to Paragraph No. 2.E. of the Stipulation, and shall submit any proposed changes to the Commission for approval.

For the purpose of determining the jurisdictional allocation of DSM/EE costs, the Company agrees to the jurisdictional allocation proposed in the testimony of Michael C. Maness on behalf of the Public Staff filed with the Commission on October 24, 2011, in Docket No. E-22, Sub 473. Such methodology develops jurisdictional allocation factors in accordance with Paragraph No. 3.B. of the Stipulation approved in Docket E-22, Sub 464.

As of November 1, 2011, in its Virginia retail jurisdiction, the Company is subject to certain cost limits, or caps, imposed by the Virginia State Corporation Commission (VSCC) on its DSM and EE expenditures through March 31, 2013, as proposed to be raised and extended through April 30, 2013, in VSCC Case No. PUE-2011-00093.

Although these caps have not been reached as of November 1, 2011, it is possible that they could be reached in the future and/or not raised or extended in the future, limiting the participation of the Company's Virginia retail jurisdictional customers in the Company's programs, relative to the participation of its North Carolina retail jurisdictional customers. Therefore, beginning with the Company's NCUC DSM/EE cost recovery proceedings in 2012, and to the extent it could impact the Company's peak demand and energy allocation factors and its ability to recover total system costs, should the Company determine: (1) that the Company expects that any caps imposed by the VSCC will limit participation by its Virginia retail jurisdictional customers in DSM and EE programs that are comparable to those approved by the NCUC,[1] or (2) that any other action by a state legislative or regulatory body, including a statute, rule, or order rejecting the Company's application for approval of a DSM or EE program in the Virginia retail jurisdiction over the long term[2] will likewise limit participation by customers in either of the retail jurisdictions relative to the other, DNCP will schedule a meeting with the Public Staff to discuss these matters. This initial meeting shall be scheduled to take place no later than two months prior to the expected date of the filing of DNCP's annual application for DSM/EE cost recovery, and shall focus on whether the North Carolina retail jurisdictional allocation factors used in the proceeding should be adjusted to reflect this limitation, and, if so, how the factors should be adjusted. DNCP will report on the outcome of these discussions in the direct testimony included in its next occurring cost recovery proceeding filing.

The Public Staff recognizes that the types of limitations discussed herein may impact the Company's ability to fully recover its system level DSM/EE costs in a manner that differs from that caused simply by different jurisdictions utilizing differing allocation methodologies, and agrees to carefully consider any such impacts in the course of its discussions with DNCP and in its ultimate recommendations to the Commission.

DNCP and the Public Staff further agree that this agreement is applicable to only DNCP's DSM/EE cost recovery proceedings, and is not intended to apply to either party's recommended jurisdictional assignment or allocation of the costs and benefits of DSM/EE programs in any other type of rate proceeding.

The foregoing Addendum Language is agreed and stipulated to this, the 3rd day of November, 2011.

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[1] DSM or EE programs not approved by the NCUC are not eligible for recovery through the NCUC DSM/EE or DSM/EE EMF riders, and thus would not be subject to this provision.

[2] See Footnote 1.

APPENDIX A
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Dominion North Carolina Power
By:____________________________

Public Staff – North Carolina Utilities Commission
By:____________________________

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APPENDIX B
PAGE 1 OF 2

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-22, SUB 473
DOCKET NO. E-22, SUB 474

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	)	NOTICE TO CUSTOMERS OF
	)	CHANGE IN RATES
In the Matter of	)	
Application of Dominion North Carolina Power for	)	
Authority to Adjust its Electric Rates Pursuant to G.S.	)	
62-133.2 and Commission Rule R8-55	)	

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission has authorized Virginia Electric and Power Company, d/b/a Dominion North Carolina Power in North Carolina, to increase its rates and charges for its North Carolina customers. The Commission-authorized rate increases will recover changes in Dominion North Carolina Power's demand-side management and energy efficiency program costs and utility incentives, as well as in its fuel costs. These rate increases will become effective for usage on and after January 1, 2012. The Commission's Orders were issued in Docket No. E-22, Sub 473, and in Docket No. E-22, Sub 474, on December 13, 2011.

Demand-Side Management and Energy Efficiency Related Rate Increase

The Commission approved a $754,581 increase in Dominion North Carolina Power's annual demand-side management and energy efficiency program rates and charges. The rate increase was approved by the Commission after review of Dominion North Carolina Power's projected demand-side management and energy efficiency program expenses and utility incentives for the calendar year 2012. These projected amounts include changes expected to be experienced by Dominion North Carolina Power with respect to its reasonable costs of and utility incentives related to implementing its demand-side management and energy efficiency programs. The rate increase is the result of the Commission's approval of a Stipulation and Agreement and Addendum to the Stipulation among the parties to this proceeding. The change in the approved demand-side management and energy efficiency programs charge for a residential customer using 1,000 kWh per month will result in a monthly increase of approximately $0.33 for usage during calendar year 2012.

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PAGE 2 OF 2

Fuel-Related Rate Increase

The Commission approved a $36,121,985 increase in Dominion North Carolina Power's annual fuel rates and charges. The rate increase was approved by the Commission after review of Dominion North Carolina Power's fuel expenses during the 12-month period ended June 30, 2011, and represents changes experienced by Dominion North Carolina Power with respect to its reasonable costs of fuel and the fuel component of purchased power. The change in the approved fuel charge will result in a monthly increase of approximately $8.78 for a residential customer using 1,000 kWh per month during calendar year 2012.

Summary of Rate Increases

Both of these rate changes will become effective for usage on and after January 1, 2012. The total monthly impact of both rate changes for a residential customer using 1,000 kWh per month is an increase of $9.11, which is a 9.62% increase.

ISSUED BY ORDER OF THE COMMISSION.
This the _13th_ day of December, 2011.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

DOCKET NO. E-7, SUB 979

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Carolinas, LLC 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 RIDER AND REQUIRING FILING OF PROPOSED CUSTOMER NOTICE

HEARD IN: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina on Tuesday, June 23, 2011, at 9:30 a.m.

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

APPEARANCES:

For Duke Energy Carolinas, LLC:

Molly L. McIntosh, K&L Gates, LLP, 214 N. Tryon Street, 47th Floor, Charlotte, North Carolina 28202

Robert W. Kaylor, Law Office of Robert W. Kaylor, P.A., 3700 Glenwood Avenue, Suite 330, Raleigh, North Carolina 27612

For the Using and Consuming Public:

Antoinette Wike, Chief Counsel and Lucy E. Edmondson, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

For Southern Alliance for Clean Energy:

Gudrun Thompson, Southern Environmental Law Center, 601 W. Rosemary Street, Suite 220, Chapel Hill, North Carolina 27516

BY THE COMMISSION: G.S. 62-133.9(d) authorizes the North Carolina Utilities Commission (Commission) to approve an annual rider to the rates of electric public utilities, outside of a general rate case, for recovery of all reasonable and prudent costs incurred for adoption and implementation of new demand-side management (DSM) and energy efficiency (EE) measures. The Commission is also authorized to award incentives to electric companies for adopting and implementing new DSM/EE measures, including rewards based on the capitalization of a percentage of avoided costs achieved by the measures. Commission

Rule R8-69(b) provides that the Commission will each year conduct a proceeding for each electric public 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 Rule R8-68. Further, Commission Rule R8-69(b) provides for the establishment of a DSM/EE experience modification factor (EMF) rider to allow the electric public utility to collect the difference between reasonable and prudently incurred costs and the revenues that were actually realized during the test period under the DSM/EE rider then in effect.

Docket No. E-7, Sub 979

In the present proceeding, Docket No. E-7, Sub 979, on February 8, 2011, Duke Energy Carolinas, LLC (Duke Energy Carolinas or the Company) filed a motion requesting an extension of time to file its annual DSM/EE rider application from March 9, 2011 to March 23, 2011. The Commission granted the motion on February 11, 2011.

On March 23, 2011, the Company filed an application for approval of its DSM/EE rider (Rider EE[1] or Rider) for Vintage Year 3 (Application) and the direct testimony and exhibits of Jane L. McManeus, Managing Director – Rates; Timothy Duff, General Manager – Energy Efficiency and Smart Grid Policy and Collaboration; and Ashlie J. Ossege, Manager – Market Analytics for Duke Energy Business Services LLC.

On March 31, 2011, the Commission issued an Order scheduling a hearing for June 23, 2011, establishing discovery guidelines, providing for intervention and testimony by other parties, and requiring public notice.

The intervention of the Public Staff has been recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e). On April 20, 2011, Carolina Utility Customers Association, Inc. (CUCA) filed a petition to intervene which was granted by Commission Order issued on April 26, 2011. Southern Alliance for Clean Energy (SACE) filed a petition to intervene on June 1, 2011, which was granted by Commission Order issued on June 6, 2011.

On June 8, 2011, the Public Staff filed its direct testimony and exhibits of Michael C. Maness, Assistant Director of the Accounting Division, and Jack L. Floyd, Electric Engineer in the Electric Division. Also on June 8, 2011, SACE filed its direct testimony and exhibits of John D. Wilson, Director of Research.

On June 21, 2011, Duke Energy Carolinas filed its rebuttal testimony and exhibits of witnesses McManeus, Duff, Ossege, and Nick Hall, President and Owner – TecMarket Works. On June 22, 2011, upon waiver of cross-examination by all parties, SACE filed a motion requesting that its witness be excused from the hearing. On that same date, the Commission issued an Order Granting Motion to Excuse Witness.

[1] Duke Energy Carolinas refers to its DSM/EE rider as "Rider EE"; however, such rider includes charges intended to recover both DSM and EE revenue requirements.

On June 23, 2011, the hearing was held as scheduled. On July 26, 2011, the Company filed three late-filed exhibits in response to questions from Commissioners at the June 23, 2011 hearing.

On August 31, 2011, Duke Energy Carolinas, the Public Staff, and SACE filed a joint motion for extension of time to file proposed orders and/or briefs requesting that the Commission extend the deadline from September 6, 2011 until September 20, 2011. In their joint motion, the parties stated that CUCA, who is an intervenor in this proceeding, had indicated that it did not object to such extension.

On September 1, 2011, the Commission issued an Order Granting Extension of Time extending the deadline for all parties to file briefs and/or proposed orders to September 20, 2011.

On September 20, 2011, Duke Energy Carolinas filed the supplemental testimony and exhibit of Timothy Duff, describing an agreement reached by Duke Energy Carolinas, SACE, and the Public Staff regarding the application of evaluation, measurement, and verification (EM&V) results to the Company's EE programs (EM&V Agreement). Also on September 20, 2011, Duke Energy Carolinas, SACE, and the Public Staff filed a Joint Proposed Order.

On September 26, 2011, Duke Energy Carolinas filed its verification for the September 20, 2011 supplemental testimony and exhibit of Timothy Duff.

On September 28, 2011, an email from CUCA's attorney was filed with the Commission indicating that CUCA has no objection to the entering of witness Duff's September 20, 2011 supplemental testimony into the record of this proceeding.

<u>Other Pertinent Docket Nos. E-7, Sub 831 and Sub 938</u>

On February 9, 2010, the Commission issued an *Order Approving Agreement and Joint Stipulation of Settlement Subject to Certain Commission-Required Modifications and Decisions on Contested Issues* in Duke Energy Carolinas' first DSM/EE rider proceeding, Docket No. E-7, Sub 831 (Sub 831 Order). In the Sub 831 Order, the Commission approved, with certain modifications, the Agreement and Joint Stipulation of Settlement between Duke Energy Carolinas, the Public Staff, SACE, Environmental Defense Fund, the Natural Resources Defense Council, and the Southern Environmental Law Center (Settlement), which described the modified save-a-watt mechanism, pursuant to which Duke Energy Carolinas calculates the revenue requirements underlying its DSM/EE riders based on percentages of avoided costs, plus compensation for net lost revenues resulting from EE programs only.

On February 15, 2010, Duke Energy Carolinas filed an Application for Waiver of Commission Rule R8-69(a)(4) and R8-69(a)(5) in Docket No. E-7, Sub 938 (Waiver Application), requesting waiver of the definitions of rate period and test period. Under the modified save-a-watt mechanism, customer participation in the Company's DSM and EE programs and corresponding responsibility to pay Rider EE are determined on a vintage year basis. A vintage year is generally the 12-month period in which a specific DSM or EE measure is installed for an individual participant or group of participants.[1] For purposes of the modified save-a-watt portfolio of programs, the Company has applied the vintage year concept on a calendar-year basis for administrative ease for the Company and its customers. Pursuant to the Waiver Application, the test period is defined as the most recently completed vintage year at the time of the Company's DSM/EE rider application filing date.

On February 24, 2010, in Docket No. E-7, Sub 938, the Commission issued an *Order Requesting Comments* on the Company's Waiver Application. After receiving comments and reply comments, the Commission entered an *Order Granting Waiver, in Part, and Denying Waiver, in Part* (Waiver Order) on April 6, 2010. In the Waiver Order, the Commission approved the requested waiver of R8-69(d)(3) in part, but denied the Company's requested waiver of the definitions of rate period and test period.

On May 6, 2010, Duke Energy Carolinas filed a Motion for Clarification or, in the Alternative, for Reconsideration, asking that the Commission reconsider its denial of the waiver of the definitions of test period and rate period, and that the Commission clarify that the EMF may incorporate adjustments for multiple test periods. In response, the Commission issued an *Order on Motions for Reconsideration* on June 3, 2010 (Second Waiver Order), granting Duke Energy Carolinas' Motion. The Second Waiver Order established that the rate period for Rider EE would align with the 12-month calendar year vintage concept utilized in the Commission-approved modified save-a-watt approach and that the test period for Rider EE would be the most recently completed vintage year at the time of the Company's Rider EE cost recovery application filing date.[2]

Consistent with the Second Waiver Order, the Company calculated Rider EE for purposes of the present proceeding (Docket No. E-7, Sub 979) using the rate period of January 1, 2012 through December 31, 2012. In addition, the present filing for Rider EE includes an EMF component for Vintage Year 1 because that vintage year has been completed as of the filing date.

On February 8, 2011, in Docket No. E-7, Sub 831, the Commission issued its *Order Adopting "Decision Tree" to Determine "Found Revenues" and Requiring Reporting in DSM/EE Cost Recovery Filings* (Found Revenues Order) which provided in Appendix A a "Decision Tree" to identify, categorize, and net possible found revenues against the net lost revenues created by the Company's EE programs. Found revenues may result from activities that directly or indirectly result in an increase in customer demand or energy consumption within Duke Energy Carolinas' service territory.

[1] Vintage Year 1 is an exception in terms of length. Vintage Year 1 is a 19-month period beginning June 1, 2009 and ending December 31, 2010, as a result of the approval of save-a-watt programs prior to the approval of the cost recovery mechanism.

[2] Further, in the Second Waiver Order the Commission concluded that Duke Energy Carolinas should true up all costs during the save-a-watt pilot through the DSM/EE EMF rider provided in Commission Rule R8-69(b)(1). The modified save-a-watt approach approved in the Sub 831 Order requires a final calculation after the completion of the four-year program, comparing the cumulative revenues collected related to all four vintage years to amounts due the Company, taking into consideration the applicable earnings cap.

Based upon consideration of Duke Energy Carolinas' application, the pleadings, the testimony and exhibits received into evidence at the hearing, the late-filed exhibits, the supplemental testimony, and the record as a whole, the Commission now makes the following

FINDINGS OF FACT

1. Duke Energy Carolinas is a public utility with a public service obligation to provide electric utility service to customers in its service area in North Carolina and is subject to the jurisdiction of the Commission.

2. The Commission has jurisdiction over this Application pursuant to the Public Utilities Act. A utility may petition the Commission for approval of an annual rider to recover all reasonable and prudent costs incurred for the adoption and implementation of new DSM and EE measures pursuant to G.S. 62-133.9 and Commission Rules R8-68 and R8-69. The Commission concludes that it has the authority to consider and approve the relief the Company is seeking in this docket.

3. Pursuant to the Commission's Second Waiver Order, issued June 3, 2010, in Docket No. E-7, Sub 938, the <u>rate period</u> for purposes of this proceeding is January 1, 2012 through December 31, 2012 (Vintage Year 3).

4. Rider EE as proposed in this proceeding includes an EMF component for Vintage Year 1 EE and DSM programs. Consistent with the Second Waiver Order, the <u>test period</u> for the EMF component is the period from June 1, 2009 through December 31, 2010.

5. Duke Energy Carolinas calculated its proposed rates for Rider EE, which includes (a) the estimated avoided cost revenue requirements for Vintage Year 3 EE and DSM programs; (b) the first year of net lost revenues for Vintage Year 3 EE programs; (c) the second year of estimated net lost revenues for Vintage Year 2[1] EE programs; and (d) the Vintage Year 1 EMF in accordance with the modified save-a-watt approach described in the Settlement and approved, with certain modifications, in the Commission's Sub 831 Order. Consistent with Finding of Fact No. 20 herein, the Public Staff's adjustment to exclude the avoided cost revenue requirement related to the Home Energy Comparison Report (HECR) Pilot Program in South Carolina from Rider EE is reasonable and appropriate. Accordingly, the calculation of Rider EE filed by Duke Energy Carolinas in its Application and the resulting billing factors as reflected in McManeus Exhibit I, should be adjusted to reflect the exclusion of the avoided cost revenue requirement related to the HECR Pilot Program. Such adjusted billing factors should become effective for the rate period January 1, 2012 through December 31, 2012, subject to appropriate true-ups in future cost recovery proceedings consistent with the Settlement, Sub 831 Order, and the EM&V Agreement.

[1] Vintage Year 2 is the 12-month period January 1, 2011 through December 31, 2011.

6. The reasonable and prudent Rider EE billing factor for residential customers, subject to later adjustment in accordance with the evidence and conclusions for Finding of Fact No. 5, is 0.2329 cents per kilowatt-hour (kWh) (including gross receipts tax and regulatory fee).

7. The reasonable and prudent Rider EE billing factor for non-residential customers who participated in Vintage Year 2, subject to later adjustment in accordance with the evidence and conclusions for Finding of Fact No. 5, is 0.0037 cents per kWh (including gross receipts tax and regulatory fee).

8. The reasonable and prudent Rider EE billing factor for non-residential customers who elect to participate in Vintage Year 3 of the Company's EE programs, subject to later adjustment in accordance with the evidence and conclusions for Finding of Fact No. 5, is 0.0406 cents per kWh (including gross receipts tax and regulatory fee).

9. The reasonable and prudent Rider EE billing factor for non-residential customers who elect to participate in Vintage Year 3 of the Company's DSM programs, subject to later adjustment in accordance with the evidence and conclusions for Finding of Fact No. 5, is 0.0526 cents per kWh (including gross receipts tax and regulatory fee).

10. The reasonable and prudent Rider EE billing factor for non-residential customers who participated in Vintage Year 1 of the Company's EE programs, subject to later adjustment in accordance with the evidence and conclusions for Finding of Fact No. 5, is 0.0218 cents per kWh (including gross receipts tax and regulatory fee).

11. The reasonable and prudent Rider EE billing factor for non-residential customers who participated in Vintage Year 1 of the Company's DSM programs, subject to later adjustment in accordance with the evidence and conclusions for Finding of Fact No. 5, is 0.0205 cents per kWh (including gross receipts tax and regulatory fee).

12. The EM&V Agreement provides that for the Company's EE programs, with the exception of the Non-Residential Smart$aver Custom Rebate Program and the Low Income Energy Efficiency and Weatherization Assistance Program, initial EM&V results shall be applied retrospectively to the beginning of the program offering to replace initial estimates of impacts. For the purposes of the vintage true-ups, these initial EM&V results will be considered actual results for a program until the next EM&V results are received. The new EM&V results will then be considered actual results going forward and applied prospectively for the purposes of truing up vintages from the first day of the month immediately following the month in which the study participation sample for the EM&V was completed. This EM&V will then continue to apply and be considered actual results until it is superseded by new EM&V results, if any.

13. The EM&V Agreement provides that EM&V for the Non-Residential Smart$aver Custom Rebate Program will not apply retrospectively and that the current true-up process, which recognizes actual participants and actual projects undertaken, should remain in effect. The EM&V Agreement also provides that the non-lighting components of the Low Income Energy Efficiency and Weatherization Assistance Program (refrigerator replacement and weatherization) were never offered to customers (due to the Company's cooperative efforts with

the State Energy Office) and will likely be replaced with a new Neighborhood Low Income Program. Thus, for the non-compact fluorescent light bulb (non-CFL) components of the Low Income Program, there will not be any EM&V impact evaluation results to apply. Under the EM&V Agreement, any EM&V performed on a new Neighborhood Low Income Program will be applied retrospectively beginning with the first day the approved new program is offered.

14. It is reasonable to apply the results of the Residential CFL Program EM&V (kWh and kW load impacts) to the CFL component of the Low Income Energy Efficiency and Weatherization Assistance program back to the beginning of the program offering, consistent with the EM&V Agreement.

15. Pursuant to the EM&V Agreement, for all new programs and pilots approved, the initial estimates of impacts will be used until Duke Energy Carolinas has valid EM&V results, which will then be applied retrospectively to the beginning of the program/pilot offering and will be considered actual results until a second EM&V is performed.

16. The EM&V Agreement is reasonable and appropriate and in the public interest.

17. Duke Energy Carolinas has made changes to the incentives of several programs to improve participation and savings without seeking Commission approval of such changes.

18. Duke Energy Carolinas should provide the Commission a list of all changes it has made to existing programs and any further proposed changes to programs, with an updated evaluation of cost effectiveness for each program using all four applicable tests, including supporting documentation for its calculations. Duke Energy Carolinas, SACE, and the Public Staff should provide to the Commission a joint proposal regarding their recommendations on whether such program modifications should be approved by the Commission.

19. The Company should file cost-effectiveness test results using all four applicable tests, including supporting documentation for its calculations for each program, with future annual DSM/EE rider applications.

20. The avoided costs associated with the South Carolina HECR Pilot Program, proposed by the Company to be included in Rider EE, should be removed from Rider EE. The determination of whether Duke Energy Carolinas can recover its reasonable and prudent allocated costs of the South Carolina HECR Pilot Program in base rates in North Carolina will be decided by a future order of the Commission after specific evidence concerning such issue has been presented to the Commission in a general rate case.

21. As soon as practicable, but no later than the Company's 2012 DSM/EE cost recovery proceeding, Duke Energy Carolinas should file for Commission review an exhibit detailing the actual and expected dates when EM&V for each program or measure will become effective.

22. In future annual DSM/EE rider applications, the Company should include with its projected schedule for EM&V explanations for delays or changes to its EM&V schedule from the prior proceeding. Further, the Company should provide a detailed explanation regarding (a) how EM&V results are applied and (b) the effects of persistence and snapback.

23. In its next DSM/EE rider proceeding, Duke Energy Carolinas and the Public Staff should include in their filings information regarding the appropriate coincident peak to be used to calculate the avoided costs benefits of specific DSM and EE programs.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1 AND 2

The evidence in support of these findings of fact can be found in the Application, the pleadings, the testimony and exhibits in this docket, as well as in the statutes, case law, and rules governing the authority and jurisdiction of the Commission. These findings of fact are informational, procedural, and jurisdictional in nature.

G.S. 62-133.9 grants the Commission the authority to approve an annual rider, outside of a general rate case, for recovery of reasonable and prudent costs incurred in the adoption and implementation of new DSM and EE measures. Similarly, Commission Rule R8-68 provides, among other things, that reasonable and prudent costs of new DSM or EE programs approved by the Commission shall be recovered through the annual rider described in G.S. 62-133.9 and Commission Rule R8-69. The Commission may also consider in the annual rider proceeding whether to approve any utility incentive pursuant to G.S. 62-133.9(d)(2)a-c.

Commission Rule R8-69 outlines the procedure whereby a utility applies for and the Commission establishes an annual DSM/EE rider. Commission Rule R8-69(a)(2) defines DSM/EE rider as "a charge or rate established by the Commission annually pursuant to G.S. 62-133.9(d) to allow the electric public utility to recover all reasonable and prudent costs incurred in adopting and implementing new demand-side management and energy efficiency measures after August 20, 2007, as well as, if appropriate, utility incentives, including net lost revenues." Commission Rule R8-69(c) allows a utility to apply for recovery of incentives for which the Commission will determine the appropriate ratemaking treatment.

G.S. 62-133.9, Rule R8-68, and Rule R8-69 establish a procedure whereby an electric public utility files an application in a unique docket for the Commission's approval of an annual rider for recovery of reasonable and prudent costs of approved EE and DSM programs as well as appropriate utility incentives, potentially including specifically "[a]ppropriate rewards based on capitalization of a percentage of avoided costs achieved by demand-side management and energy efficiency measures." Consistent with the modified save-a-watt mechanism as approved by the Sub 831 Order, the cost recovery and incentives the Company seeks through Rider EE are based upon paying the Company a percentage of the avoided capacity costs achieved by DSM measures, and a separate percentage of the net present value (NPV) of avoided capacity costs and avoided energy costs achieved by EE measures. In addition, the Settlement provides for a limited period of recovery of the Company's net lost revenues resulting from implementation of its EE measures. The Commission concludes that it has the authority to consider and approve the relief the Company is seeking in this docket.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3 AND 4

The evidence in support of these findings of fact can be found in the Second Waiver Order; in the testimony of Company witnesses McManeus and Duff; and in the testimony of Public Staff witness Maness. The rate period and inclusion of an EMF component for Rider EE are consistent with the Commission's ruling in the Second Waiver Order, and are uncontroverted by any party.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5 THROUGH 11

The evidence in support of these findings of fact can be found in the Sub 831 Order; in the Company's Application; in the testimony and exhibits of Company witnesses McManeus, Ossege, and Duff; in the testimony of SACE witness Wilson; and in the testimony of Public Staff witnesses Maness and Floyd.

On March 23, 2011, Duke Energy Carolinas filed its Application seeking approval of Rider EE, which includes the formula for calculation of the Rider, as well as the proposed billing factors to be effective for Vintage Year 3. SACE witness Wilson,[1] Company witness McManeus, and Public Staff witness Maness testified that the method by which Duke Energy Carolinas has calculated its proposed Rider is the modified save-a-watt mechanism as described in the Settlement and approved, with certain modifications, in the Sub 831 Order.

Modified Save-a-Watt Mechanism

The modified save-a-watt mechanism is a four-year pilot, with an extension allowed beyond the four years to allow for the recovery of net lost revenues experienced due to EE measures installed or implemented during the four years. Duke Energy Carolinas is allowed to recover in revenues 75% of the avoided capacity costs resulting from its DSM measures installed or implemented during the four-year term, and 50% of the NPV of avoided capacity and energy costs resulting from its EE measures installed or implemented during the same period. The Company is also allowed to recover 36 months of net lost revenues resulting from the installation of EE measures.[2] Initial revenue requirements are set based on 85% of targeted savings. Customer participation in the Company's DSM and EE programs, and corresponding responsibility to pay Rider EE, are determined on a vintage year basis.

1 SACE witness Wilson testified that SACE did not have any specific recommendations regarding the Company's proposed rider; however, SACE stated that it would like to review the testimony of the Public Staff and any other intervenors as well as any rebuttal testimony prior to forming a final opinion. At the June 23, 2011 hearing, SACE informed the Commission that witness Wilson's final opinion had not changed upon reading the Public Staff's testimony and Duke Energy Carolina's rebuttal testimony. Furthermore, SACE was a party to the Joint Proposed Order filed on September 20, 2011.

2 Pursuant to the Sub 831 Order, such recovery of net lost revenues will end upon Commission approval of an alternative recovery mechanism, or the implementation of new rates in a general rate case or comparable proceeding to the extent that rates set in a rate case or comparable proceeding are set to explicitly or implicitly recover those net lost revenues. Recovery of net lost revenues for vintage year installations not covered by the new rates will continue, subject to the 36-month limitation.

ELECTRIC – RATE SCHEDULES/RIDERS/SERVICE RULES AND REGULATIONS

The Settlement approved in the Sub 831 Order, with certain modifications, provides for a series of annual true-ups that will be conducted to update revenue requirements based on actual customer participation results. Additionally, Duke Energy Carolinas' final avoided cost-related revenue requirements over the four-year period will be based on its measured and verified savings achieved. The final avoided cost-related revenue requirements will also be subject to an earnings cap, with earnings measured as the excess of revenue requirements over DSM or EE program costs. Additionally, the Found Revenues Order provides a mechanism to identify, categorize, and net possible found revenues from net lost revenues that stem from the Company's EE programs.

Calculation of Rider EE

Company witness McManeus described how the Company calculated Rider EE as proposed in this proceeding in accordance with the modified save-a-watt mechanism. She testified that the estimated revenue requirements for Vintage Year 3 are determined separately for residential and non-residential customer classes and are based on the expected avoided costs (and associated net lost revenues) to be realized at an 85% level of achievement of targeted savings. Consistent with the modified save-a-watt mechanism, the proposed Rider is designed to allow Duke Energy Carolinas to collect a level of revenue equal to 75% of its estimated avoided capacity costs applicable to DSM programs and 50% of the NPV of estimated avoided capacity and energy costs applicable to EE programs, as well as estimated net lost revenues for EE programs. Witness McManeus explained that as a result, the revenue requirements for proposed Rider EE include: (1) the avoided cost revenue requirements for Vintage Year 3 DSM programs; (2) the avoided cost revenue requirements and the first year of net lost revenues for Vintage Year 3 EE programs; (3) the second year of net lost revenues for Vintage Year 2 EE programs; and (4) the EMF participation true-up for Vintage Year 1.

With respect to the third year of net lost revenues for Vintage Year 1, witness McManeus testified that such revenues are not included in the rate period revenue requirements due to the Company's Summer 2011 planned general rate case filing. Witness McManeus explained that the Settlement provides that the recovery of net lost revenues shall cease upon the implementation of new rates in a general rate case to the extent that the new rates are set to recover net lost revenues. Because Vintage Year 1 overlaps with the test period for the upcoming rate case, the net lost revenues for year 3 of Vintage Year 1 will be captured in the new rates effective January 1, 2012, and cannot be included in the proposed Rider 3 which is also effective January 1, 2012. Witness McManeus testified that the Company is not including net lost revenues for year 3 of Vintage Year 1 in Rider 3 to avoid double recovery of those lost revenues.

McManeus Exhibit 1 sets forth the calculations of the residential and non-residential billing factors. Witness McManeus explained that the numerator of the residential billing factor is calculated by first adding the DSM component of the avoided cost revenue requirement to the EE component of the avoided cost revenue requirement to get the residential avoided cost revenue requirement. She testified that the residential avoided cost revenue requirement is then multiplied by the gross receipts tax and regulatory fee factor to obtain the adjusted residential avoided cost revenue requirement. As explained by witness McManeus, this figure is then added to net lost revenues for the second year of Vintage Year 2 programs and the net lost revenues for the first year of Vintage Year 3 programs to obtain the residential save-a-watt revenue requirement,[1] the numerator of the billing factor. The residential save-a-watt revenue requirement is then divided by a denominator consisting of the projected North Carolina residential retail kWh sales for Vintage Year 3 to obtain the residential billing factor. Witness McManeus testified that the calculation of the non-residential billing factors is essentially the same, using non-residential inputs instead. However, she added, because non-residential customers are allowed to opt out of either DSM or EE programs separately in an annual election, non-residential billing factors have been separately computed for DSM versus EE programs and within EE programs, by vintage.

Witness McManeus also described the calculation to determine the DSM and EE components. In particular, the DSM component is calculated by multiplying the projected kW demand impacts from DSM measures for Vintage Year 3, the Company's annual avoided capacity costs per kW, and 75%. Similarly, the EE component is calculated by multiplying the projected kW demand impacts from EE programs by the annual avoided capacity costs per kW from the Avoided Cost Filing.[2] The next step is to take the NPV of these numbers and multiply the result by 50%. The avoided cost of energy revenue requirement is calculated by first multiplying the projected kWh impacts for the EE programs by the Company's annual avoided energy costs, determining the NPV of those numbers; and multiplying by 50%. No party disputed the methodology of the Company's DSM and EE component calculations for Rider EE, as described by witness McManeus. Furthermore, these calculations are consistent with the method adopted by the Commission in the Sub 831 Order.

Witness McManeus then described how the net lost revenue component of the billing factors was determined. She testified that net lost revenues were estimated by multiplying the portion of the Company's tariff rates that represent the recovery of fixed costs by the estimated kW and kWh reductions applicable to EE programs. She explained that the Company calculated the portion of retail tariff rates representing the recovery of fixed costs by deducting the recovery of fuel and variable operating and maintenance (O&M) costs from its tariff rates. According to witness McManeus, the kWh reductions to which the fixed cost rates are applied reflect 12 months of expected reductions, representing one year out of the total three years of net lost revenues recoverable, for each applicable vintage. Rider EE includes net lost revenues for the second year of Vintage Year 2 programs in addition to net lost revenues for the first year of Vintage Year 3 programs. For the Vintage Year 3 net lost revenues, the kWh reductions to which the fixed costs rates are applied reflect an assumption that enrollment in programs will be staggered throughout the year, using a "half-year convention" (i.e., six months of net lost revenues), to minimize the potential for overcollection. Witness McManeus observed that the Company is not recovering net lost revenues on its DSM programs. She also stated that net lost revenues and found revenues were calculated at the North Carolina retail level, rather than at a system level, aligning results with how fixed costs would be recovered from retail customers in base rates. Lastly, she testified that actual net lost revenues for year one of Vintage Year 1 for

[1] Revenue requirements are set at 85% achievement of target avoided costs savings.

[2] Docket No. E-100, Sub 106.

residential customers were calculated by taking the weighted average of residential rate schedules RS and RE. Further, witness McManeus explained that the actual net lost revenues for year one of Vintage Year 1 for non-residential customers was calculated by taking the weighted average of Schedules OPT-I and OPT-G, the two rate schedules that have the most participation in the Company's DSM and EE programs.

Witness McManeus explained that the Vintage Year 3 component of Rider EE contains an estimate of found revenues to offset lost revenues for year one of the Vintage Year 3 programs. She testified that the Vintage Year 2 lost revenue component of Rider EE has been adjusted by an estimate of found revenues for year two of Vintage Year 2 programs. Additionally, the EMF component of Rider EE, which trues up for participation in Vintage Year 1, has also been adjusted to incorporate found revenues into the true-up of lost revenues for year 1 of Vintage Year 1. According to witness McManeus, other adjustments to lost revenues include the opt-out adjustment and the load impacts from EM&V data. Witness McManeus also noted that the lack of an election period related to Vintage Year 3 has caused the Company to use currently known information regarding Vintage Year 2 opt-out elections to estimate Vintage Year 3 elections. Furthermore, the Company has received load impact results for its CFL measure. Accordingly, witness McManeus testified that the Vintage Year 3 component of Rider EE incorporated the updated CFL load impact results in the estimates of avoided cost revenue requirements for Vintage Year 3 DSM programs, avoided cost revenue requirements for Vintage Year 3 EE programs, and the first year of net lost revenues for Vintage Year 3 EE programs.

In addition to describing the DSM and EE components and the net lost revenue calculations, witness McManeus explained the calculation of the Rider EE Vintage Year 1 EMF component. The EMF includes updates for actual participation, lost margins, found revenues, and certain pilot programs for Vintage Year 1. McManeus Exhibit 3 demonstrates the calculations of the EMF. Additionally, witness McManeus explained that the Company's avoided cost rates used in the calculation of the avoided cost revenue requirements for Rider EE remain unchanged because they have not increased or decreased more than 25% from those fixed at the outset of the Settlement. Witness McManeus also provided testimony regarding allocation of the revenue requirements for Rider EE. In particular, she explained that the revenue requirement amounts for non-residential customers differ depending on customer participation elections. Furthermore, she explained that the revenue requirement levels included in the billing factors are calculated based on 85% achievement of target savings.

While not challenging the methodology used in the Company's calculation of net lost revenues for the prospective and EMF components of Rider EE as described by Duke Energy Carolinas witness McManeus, the Public Staff presented two exceptions to the Company's calculated Rider EE components. First, as addressed in the Evidence and Conclusions for Finding of Fact No. 20, Public Staff witnesses Floyd and Maness recommended that the revenue requirements associated with the South Carolina HECR Pilot Program should be excluded from Rider EE. The Public Staff asserted that the avoided costs related to the HECR Pilot Program which has been approved in South Carolina by the South Carolina Public Service Commission, but has not been approved by the North Carolina Utilities Commission, and for which no program approval application is pending, should not be allocated to customers in North Carolina.

In Maness Exhibit I, witness Maness sets forth the Public Staff's calculation of the residential components of Rider EE, excluding the revenue requirements related to the HECR Pilot Program.

Second, Public Staff witness Maness contended that the Company's incorporation of the updated load impact results for its residential CFL and non-residential lighting-related programs for Vintage Year 1 was inconsistent with the Settlement, as approved by the Commission in the Sub 831 Order. As discussed in the Evidence and Conclusions for Findings of Fact Nos. 12 through 16, the Company, SACE, and the Public Staff subsequently entered into the EM&V Agreement regarding the incorporation of updated load impacts for the Company's portfolio of DSM and EE programs. Pursuant to the EM&V Agreement, the Company, SACE, and the Public Staff agreed that the Company's approved Rider EE should go into effect beginning January 1, 2012, and that any adjustments to the Vintage Year 1 true-up portion of Rider EE due to the EM&V Agreement will be made in the Company's next DSM/EE rider filing in March 2012.

As set forth in the Evidence and Conclusions for Findings of Fact Nos. 12 through 16 herein, the Commission finds and concludes that the EM&V Agreement is reasonable and appropriate and in the public interest. Furthermore, as set forth in the Evidence and Conclusions for Finding of Fact No. 20, the Commission concludes that the Public Staff's adjustment to exclude the revenue requirements associated with the HECR Pilot Program from the calculation of Rider EE is reasonable and appropriate. The components of Rider EE and the resulting billing factors set forth in Findings of Fact Nos. 5 through 11 appropriately reflect the Commission's findings and conclusions herein and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12 THROUGH 16

The evidence in support of these findings of fact can be found in the Application; in the direct testimony of Company witness McManeus; in the rebuttal testimony of Company witnesses Duff, Ossege and Hall; in the testimony of Public Staff witness Maness; in the supplemental testimony of Company witness Duff, and in the record in the Sub 831 docket.

In her direct testimony, Duke Energy Carolinas witness McManeus explained how the Company would incorporate updated load impact results from EM&V data and conduct annual participation true-ups and a final true-up pursuant to the Company's interpretation of the Settlement approved, with certain modifications, in the Sub 831 Order. She pointed to Section I.4 of Exhibit B of the Sub 831 Settlement, which states, "[t]he initial estimates of load impact and free ridership (gross to net) will be used until the first set of impact evaluations is completed. The results from those impact evaluations will then be used prospectively until the next set is completed."

Based upon that section of the Sub 831 Settlement, Duke Energy Carolinas incorporated the updated load impact results from EM&V data prospectively into its calculations of Rider EE. Duke Energy Carolinas witness Hall offered testimony that retrospective application of EM&V results had caused uncertainty and created disincentives to pursue EE in California, and recommended against the retrospective application of EM&V. Company witness Ossege testified on rebuttal that retrospective application of EM&V could add significant volatility, uncertainty, and unpredictability to the EM&V results.

Public Staff witness Maness disagreed with Duke Energy Carolinas' interpretation of the Sub 831 Settlement regarding the incorporation of updated load impacts, and pointed to Sections H.5, H.6, I.2, and I.5 of Exhibit B; the Settlement testimony and exhibits of Company witnesses Schultz and Farmer; verified information submitted by the Company; and the final tariff approved by the Commission in Sub 831. According to witness Maness, the Settlement provides that EM&V will be used to true up estimated energy and capacity savings with achieved energy and capacity savings. Thus, the dispute between Duke Energy Carolinas and the Public Staff involved whether the Settlement required EM&V data to be used only prospectively, or both prospectively and retrospectively in calculating the EMF and net lost revenues.

SACE witness Wilson testified that the Company was correctly implementing the Sub 831 Settlement by using "deemed savings" based on industry experience. In his supplemental testimony, Duke Energy Carolinas witness Duff testified that the Company had learned through subsequent discussions that SACE shared the Public Staff's view that the Company should true up its original impact estimates to reflect results based upon EM&V conducted on the programs in the Carolinas, during or prior to the final true-up of the modified save-a-watt pilot.

Following the hearing in the present proceeding, the Company, SACE, and the Public Staff were able to reach agreement regarding the application and incorporation of updated load impacts from EM&V data. Under this EM&V Agreement, for the purposes of resolving the dispute over the interpretation of the Sub 831 Settlement, Duke Energy Carolinas agreed that initial EM&V results[1] shall be applied retrospectively to program impacts that were based upon estimated impact assumptions. Thus, Duke Energy Carolinas witness Duff explained that for all of the Company's EE programs, with the exception of the Non-Residential Smart$aver Custom Rebate Program and the Low Income Energy Efficiency and Weatherization Assistance Program, the initial EM&V results would be applied retrospectively to the beginning of the program offering. For vintage true-ups, the initial EM&V results will be considered actual results for a program until the next EM&V results are received. Witness Duff further testified that the initial EM&V results will continue to apply and be considered actual results until superseded by new EM&V results, if any.

In regard to the Non-Residential Smart$aver Custom Rebate Program (Custom Program), Company witness Duff explained that it was the Company's view that EM&V should not apply retrospectively because the program is fundamentally different than other programs as each Custom Program project and impact is unique. Witness Duff explained that while EM&V for most EE programs yields net savings impacts, the EM&V associated with the Custom Program will yield realization rates that can be applied to general categories of technology as a

[1] EM&V results are the outputs of both process and impact evaluations performed by Duke Energy Carolinas' independent third-party evaluator and may include any or all of the following: kWh and kW load impacts, net to gross savings analysis, and realization rates.

means to improve the estimate of savings for future projects. Because this realization rate reflects market conditions and the general state of technology at the time of the sample, witness Duff stated that it is appropriate to apply the realization rate going forward for the Custom Program. Thus, under the EM&V Agreement, Duke Energy Carolinas' current true-up process for this program, which recognizes actual participants and actual projects undertaken, would remain in place.

In regard to the Low Income Energy Efficiency and Weatherization Assistance program (Low Income Program), Duke Energy Carolinas' witness Duff testified that the non-lighting components of the program (refrigerator replacement and weatherization) were never offered to customers (due to the Company's cooperative efforts with the State Energy Office) and will likely be replaced with a new Neighborhood Low Income Program. Thus, for the non-CFL components of the Low Income Program, witness Duff noted that there will not be any EM&V impact evaluation results to apply. Under the EM&V Agreement, any EM&V performed on a new Neighborhood Low Income Program will be applied retrospectively beginning with the first day the approved new program is offered.

Public Staff witness Floyd and Company witnesses Ossege and Duff addressed Duke Energy Carolinas' application of the EM&V results (kWh and kW load impacts) from the Residential CFL Program to the CFL components of its Low Income Program. Witness Ossege testified that the Company has agreed to include with its next DSM/EE rider application an explanation of how it applied EM&V data, including the programs or measures to which impacts are being applied. Witness Duff explained that it was appropriate to apply the EM&V results from the Residential CFL Program to the CFL components of the Low Income Program because in both of these programs, the customers receive bulbs and are responsible for installing the bulbs themselves. Under the EM&V Agreement, the parties to the Agreement have agreed that the results of the Residential CFL Program EM&V (kWh and kW load impacts) may be applied to the CFL components of the Low Income Program back to the beginning of the program offering.

For all new programs and pilots, under the EM&V Agreement, initial estimates of impacts will be used until Duke Energy Carolinas has valid 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. Finally, the parties to the EM&V Agreement have agreed that the Company's proposed Rider EE in the current proceeding would go into effect beginning January 1, 2012, and that any adjustments to the Vintage Year 1 true-up portion of Rider EE resulting from the EM&V Agreement should be made in the Company's next DSM/EE rider filing in March 2012.

The Commission finds that the EM&V Agreement, as explained in the supplemental testimony of Duke Energy Carolinas witness Duff, supplies a more detailed and specific understanding regarding the application of EM&V pursuant to the Sub 831 Settlement and ensures that customers will not be subject to the potential risk associated with original program estimates. The EM&V Agreement is found to be reasonable and appropriate and in the public interest, and is accepted by the Commission as a fair and reasonable resolution of the issues in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 17 THROUGH 19

The evidence in support of these findings of fact can be found in the testimony of Company witness Duff and Public Staff witness Floyd.

On February 26, 2009, in Docket No. E-7, Sub 831, the Commission issued its *Order Resolving Certain Issues, Requesting Information on Unsettled Matters and Allowing Proposed Rider to Become Effective Subject to Refund* (*February 26, 2009 Order*). Such Order requires Commission approval of: (1) changes in program costs greater than 20%; (2) changes that resulted in program savings of greater than 20%; (3) any change to the participant incentives offered; (4) changes to the target customer group; (5) any changes that would result in the reassignment of costs and benefits from one class to another; or (6) any combination of the first five criteria. Section J. 2 of the Settlement filed in Sub 831 states: "Consistent with the North Carolina Utilities Commission's February 26, 2009, Order in this docket, the Company will submit all new programs and major program modifications to the Commission for approval."

Public Staff witness Floyd testified that Duke Energy Carolinas has changed the incentives of several programs to improve participation and savings. He noted that while the Company did not receive Commission approval prior to making these changes, he does not believe that many of the changes made to program incentives for the purpose of addressing lackluster participation or reducing costs should necessarily require Commission approval as first contemplated in Sub 831. Witness Floyd recommended that the Commission require the Company to file a full accounting of all changes it has made to existing programs and a proposal for any further changes to programs, with an updated evaluation of cost effectiveness for each program using all four applicable tests, including supporting documentation for its calculations. He also proposed that in future DSM/EE rider proceedings, Duke be required to file these test results with its application.

However, witness Floyd testified that he supported modification of the Sub 831 requirement that Duke Energy Carolinas seek Commission approval prior to making changes to its DSM and EE programs. He opined that the Company could maximize its portfolio's effectiveness if it were able to make program changes, including changes to incentives, as long as the changes have limited impact on program and portfolio cost effectiveness. Witness Floyd proposed that the Company and the Public Staff continue discussing revisions to the program flexibility requirements and file a joint proposal in Docket No. E-7, Sub 831, within 90 days of a Commission Order in this proceeding. He testified that it would be appropriate for SACE to participate in the discussions and formulation of the proposal. Duke Energy Carolinas' witness Duff testified that working with the Public Staff to create a formal proposal would help the Company better optimize its programs and improve the value customers realize from the Company's portfolio of DSM and EE programs.

The Commission concludes that the issue of program modifications should be reviewed in Docket No. E-7, Sub 831, as well as the pertinent docket for the various EE or DSM programs approved subsequent to the Sub 831 docket. Further, as agreed to by the parties in their Joint Proposed Order, within 30 days of the issuance of this Order the Company should file a list of all changes it has made to existing programs and a proposal for any further changes to programs, with an updated evaluation of cost effectiveness for each program using all four applicable tests, including supporting documentation for its calculations.. The Commission also concludes that the Company, SACE, and the Public Staff should discuss revisions to the program flexibility requirements in the February 26, 2009 Sub 831 Order and file a joint proposal within 90 days of this Order, as agreed to by the parties in their Joint Proposed Order. Finally, the Commission finds and concludes that there is merit to witness Floyd's recommendation that the Company should be required to file cost-effectiveness test results for each program with its application. An annual review of cost-effectiveness would allow the Commission to monitor the progress and success of the Commission-approved programs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 20

The evidence in support of this finding of fact can be found in G.S. 62-133.9; in Commission Rules R8-68 and R8-69; and in the testimony of Company witnesses McManeus and Duff and Public Staff witnesses Floyd and Maness.

Duke Energy Carolinas witness Duff testified that the HECR Pilot Program was approved as a 12-month pilot by the Public Service Commission of South Carolina in Docket 2010-50-E on March 24, 2010, and had been recently completed. Public Staff witness Floyd testified that Duke Energy Carolinas filed for approval of a HECR Pilot Program in North Carolina on June 7, 2010. The Public Staff reviewed the application and filed comments recommending approval of the HECR Pilot Program and denial of Duke Energy Carolinas' proposed recovery of lost revenues. Following further discussions with Duke Energy Carolinas, the Public Staff filed additional comments recommending that the HECR Pilot Program should be approved and such program should be eligible for lost revenues if it were ultimately found to be cost effective. However, on November 24, 2010, Duke Energy Carolinas withdrew its application for approval of the HECR Pilot Program in North Carolina.

Witness McManeus testified that it is appropriate to allocate avoided costs from the HECR Pilot Program to North Carolina retail customers because of the way the modified save-a-watt compensation mechanism is structured. Under the modified save-a-watt mechanism as approved by the Commission in Docket No. E-7, Sub 831, Duke Energy Carolinas is compensated based on predetermined percentages of the Company's capacity- and energy-related "avoided cost," an estimate of the cost of supplying electricity. In other words, the modified save-a-watt mechanism provides for compensation to Duke Energy Carolinas for successful implementation of EE and DSM programs on the basis of a discount to the avoided costs of a power plant, rather than on the basis of what the Company spends on DSM and EE programs. Witness McManeus explained that just as a power plant built by Duke Energy Carolinas in South Carolina provides system benefits to the Company's customers in North and South Carolina, a DSM or EE program approved and implemented in South Carolina provides system benefits – by delaying or avoiding the cost of constructing new supply-side resources – to customers in both North and South Carolina. As such, Duke Energy Carolinas believes it is appropriate to allocate avoided costs from the HECR Pilot Program (or any other program approved in South Carolina but not North Carolina) to North Carolina customers, and that it is likewise appropriate for the Company to allocate the avoided costs of a DSM or EE program approved in North Carolina but not South Carolina to South Carolina customers. As witness

McManeus testified, the Company has allocated the avoided costs for the Smart Energy Now Program, which is currently being piloted only in North Carolina, to both North and South Carolina customers.

Witness McManeus further testified that costs that are avoided through the operation of DSM and EE programs are for the most part demand- and energy-driven generation and transmission costs. The Company operates its generation and transmission system on a total-system basis to serve all customers in its service territory across two states. Accordingly, for ratemaking purposes, the Commission traditionally has not directly assigned system-level generation and transmission costs to either North or South Carolina, but instead has allocated those costs to each state on the basis of demand at the system peak and annual energy usage as percentages of system peak demand and annual energy usage. Thus, the costs avoided by utilization of DSM and EE, if incurred instead, would likely have been handled for ratemaking purposes by aggregating them with other generation and production costs on a total system basis and allocating them by state. Accordingly, assigning avoided costs for DSM and EE programs approved in one state to only that state would result in that state subsidizing the other and would discourage either state from approving DSM and EE programs. Witness McManeus concluded that if the Company is not permitted to recover avoided costs for HECR from North Carolina customers despite the fact that HECR produces system benefits, then either South Carolina customers would be subsidizing North Carolina customers, just as if the Company were to recover in rates the costs of a generation asset built in South Carolina from South Carolina customers only, or the Company would have stranded costs which it could not recover.

With respect to the recovery of net lost revenues, witness McManeus testified that because net lost revenues are determined on a state and class-specific basis, net lost revenues from the HECR Pilot Program are not included in Rider EE and will not be included in the EMF. She stated that net lost revenues are recovered when the Company has undercollected the amount of system fixed costs that have been allocated to a particular retail jurisdiction. Thus, witness McManeus contended that it is appropriate to allocate net lost revenues for the HECR Pilot Program to South Carolina, rather than a system allocation, because this produces a result that aligns with how fixed costs would be recovered from retail customers in base rates and maintains the proper allocation of fixed costs among rate jurisdictions.

Witness McManeus testified that "the ability to recover through a rider our DSM and EE programs as a result of this Senate Bill 3 should apply to all reasonable and prudent costs incurred with a DSM program and it should not be bifurcated into a base rate recovery separately from a rider EE recovery." In her rebuttal testimony, witness McManeus pointed out that, although Commission Rule R8-69(b)(1) refers to "measures previously approved pursuant to Commission Rule R8-68," there are several places in the statute and the Commission rules that support the concept of EE and DSM programs being viewed as system resources that should be paid for by the retail customers that directly benefit from the programs. Notably, she cited the definition of DSM/EE rider in Rule R8-69(a)(2) which states, in part, that such charge or rate should "allow the electric public utility to recover all reasonable and prudent costs incurred in adopting and implementing new demand side management and energy efficiency measures." She also noted that G.S. 62-133.8(b) requires electric power suppliers to implement DSM and EE measures and incorporate them into its resource plans for meeting the electricity needs of its customers, and that G.S. 62-133.9(d) allows the electric public utility to seek cost recovery for "all reasonable and prudent costs incurred for adoption and implementation of new demand-side management and new energy efficiency measures." Witness McManeus contended that since Duke Energy Carolinas uses one system of resources to supply customers across two states, it is appropriate to allocate to North Carolina customers a portion of the reasonable and prudent costs of all programs that are implemented as part of the Company's plan to meet electricity needs of customers in both states.

On cross-examination, witness McManeus testified that if the Commission had rejected an application for an EE or DSM program filed by the Company, but the same program was approved in South Carolina, she would recommend that the Company should be allowed recovery for the program in North Carolina based on the kilowatts or kilowatt hour savings. She agreed that the objective of Senate Bill 3 was to promote the development of renewable energy and energy efficiency in North Carolina, rather than South Carolina, but pointed out that North Carolina customers benefitted from impacts realized in South Carolina.

Witness Floyd testified that Commission Rule R8-69(b)(1) states that an EE rider may be established pursuant to Commission Rule R8-69 to recover costs related to programs that have been approved pursuant to Commission Rule R8-68. As the South Carolina HECR Pilot Program is not an approved EE program pursuant to Commission Rule R8-68, he stated that it is inappropriate for Duke Energy Carolinas to include its costs in the costs used to calculate the Vintage Year 3 Rider EE. Public Staff witness Maness incorporated witness Floyd's recommendation to exclude the costs associated with the HECR Pilot Program from the calculations of the Public Staff's recommended Vintage Year 1 and Vintage Year 3 billing factors, which are set forth on Maness Exhibit 1.

In response to questions from the Commission as to whether there was some inconsistency in its exclusion of the costs of the South Carolina HECR Pilot Program and its allocation of costs of the Smart Energy Now Pilot Program to the South Carolina jurisdiction, witness Floyd noted that the allocation of the costs of the Smart Energy Now Pilot Program to the South Carolina jurisdiction was consistent with the save-a-watt mechanism adopted in Docket No. E-7, Sub 831. Witness Maness stated that the Public Staff does not dispute that the reasonable and prudent costs of the HECR Pilot Program in South Carolina could be recovered through base rates in North Carolina as part of a general rate case. He pointed out that the Public Staff is only disputing the recovery of the costs of the HECR Pilot Program through the DSM/EE rider. Witness Maness contended that Commission Rule R8-69 expressly requires that the program has to be approved in North Carolina for its costs to be recovered through the rider. He posited that this may be due in part to the fact that until a program has come before the Commission, it has not had a chance to formally evaluate that program and determine if it is an appropriate DSM or EE program. Witness Maness opined that the requirement that the program be approved in North Carolina is an appropriate protection mechanism for North Carolina customers regardless of its treatment in South Carolina. In regard to the Smart Energy Now Pilot Program, he noted that it had been approved by the Commission in its current form and was appropriately included in the DSM/EE rider. Further, witness Maness stated that in regard to the HECR Pilot Program the issue is not whether its costs should be allocated, but whether the costs should be recovered through the rider or through base rates.

G.S. 62-133.9(c) requires electric power suppliers to submit cost-effective DSM and EE options that require incentives to the Commission for approval. Accordingly, subsections (b)(1) and (c)(1) of Commission Rule R8-69 include the requirement that program approval precede recovery through a DSM/EE rider of either costs or incentives. Regardless of the system benefits that may be produced by the HECR Pilot Program approved in South Carolina, it has not been approved by this Commission pursuant to Commission Rule R8-68. The Public Staff filed its testimony on June 8, 2011, maintaining that cost recovery was inappropriate due to the Company's failure to file the program for approval. As of this date, Duke Energy Carolinas still has not filed the program for approval. Therefore, the Commission finds and concludes that the HECR Pilot Program is not eligible for inclusion in Rider EE in North Carolina. Accordingly, the Commission finds and concludes that the avoided cost revenue requirement related to the HECR Pilot Program should be excluded from Rider EE and the residential billing factors included on Maness Exhibit I filed on June 8, 2011, are reasonable and appropriate and should be approved.

With respect to the Public Staff's assertion that the reasonable and prudent costs of the HECR Pilot Program in South Carolina could be recovered through base rates in North Carolina as part of a general rate case, the Commission notes that such recovery in base rates is not before the Commission in this proceeding. Such a determination cannot be made by the Commission until specific evidence concerning this issue is presented to the Commission in a general rate case.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 21 THROUGH 23

The evidence in support of these findings of fact can be found in the testimony of Company witnesses Duff and Ossege, SACE witness Wilson, and Public Staff witness Floyd.

The present proceeding is the first proceeding in which Duke Energy Carolinas has presented EM&V data which has been incorporated into its DSM/EE rider. Consequently, this is the first proceeding in which the Public Staff and SACE raised several issues regarding the EM&V analyses or the overall EM&V process.

SACE witness Wilson presented a chart that indicated that certain EM&V analyses have been delayed. In some cases the delay was without explanation. Witness Wilson asserted that Duke Energy Carolinas should complete the EM&V analyses in a timelier manner and should also keep the Carolinas Energy Efficiency Collaborative[1] (Collaborative) better informed on the status of EM&V analyses. Witness Wilson testified that on August 31, 2010 the Company provided a report to the Collaborative that outlined the Company's schedule for completing EM&V analyses, but since that time Duke Energy Carolinas has not included any update regarding such matters to the Collaborative. Company witness Ossege disputed that the EM&V reports are delayed. She explained that the Company cannot forecast exactly when the reports

[1] The Carolinas Energy Efficiency Collaborative is the regional efficiency advisory group established pursuant to the Sub 831 Settlement to review the EM&V process, collaborate on new program ideas, and review changes to existing programs.

will begin or end. Further, witness Ossege noted that the Company files with its rider application a projected schedule for EM&V.

As set forth in the Joint Proposed Order, the parties agreed that Duke Energy Carolinas should file for Commission review an exhibit detailing the actual and expected dates when each program or measure's EM&V will become effective as soon as practicable, but no later than the Company's 2012 DSM/EE cost recovery proceeding. Further, the parties agreed that Duke Energy Carolinas should include, with its projected schedule for EM&V, explanations for delays or changes to its EM&V schedule from the prior proceeding. The Commission finds and concludes that the agreed-upon filings are reasonable and appropriate and should be approved.

Public Staff witness Floyd recommended that Duke Energy Carolinas provide in future rider applications an explanation as to how EM&V results are applied, including the date it begins using updated impacts or participation results in its calculations or models, the programs or measures to which it applies the results, an analysis of the costs associated with performing additional EM&V work for other measures, and any other pertinent information regarding the applicability of the EM&V findings to the other CFL measures, including any differences in the characteristics of the targeted participants that would alter savings estimates. Duke Energy Carolinas witness Ossege responded that the Company would provide in its next rider filing the detail regarding EM&V suggested by witness Floyd. The Commission finds and concludes that in its future DSM/EE rider applications, the Company should provide an explanation as to how EM&V results are applied, including:

(a) the date it begins using updated impacts or participation results in its calculations or models;
(b) the programs or measures to which it applies the results;
(c) an analysis of the costs associated with performing additional EM&V work for other measures; and
(d) any other pertinent information regarding the applicability of the EM&V findings to the other CFL measures, including any differences in the characteristics of the targeted participants that would alter savings estimates.

Further, witness Floyd contended that in future proceedings the Company's EM&V should address persistence and snapback, or explain why it should not be applicable. Duke Energy Carolinas witness Ossege testified that both snapback and short-term persistence are already measured and included in the EM&V reports, though not explicitly, primarily through billing analysis and on-site metering. She explained that the long-term effects of persistence could not be directly measured during the current 12- to 18-month cycle for each EM&V report, but would require regular, cyclical studies with the same respondents over the life of each measure. Moreover, witness Ossege indicated that such long-term evaluations would increase the cost of EM&V reporting significantly and would provide little, if any, increase in the accuracy of the analysis. Finally, she pointed out that the results from such a long-term study would only be available well after the end of the four-year save-a-watt pilot program. Duke Energy Carolinas witness Duff noted that the Company had agreed to explain the effects of persistence and snapback in future DSM/EE rider filings. The Commission finds and concludes that in future DSM/EE rider applications, the Company should explain the effects of persistence and snapback.

In regard to the Residential SmartSaver CFL EM&V report (Exhibit A to Company witness Ossege's direct testimony) and the High Bay Lighting EM&V report (Exhibit B to Company witness Ossege's direct testimony), Public Staff witness Floyd recommended that the coincident peaks be recalculated using a coincident peak at the time of system peak. Duke Energy Carolinas witness Duff testified, in response, that because logger studies for these measures were done at the equinox, no calibration is necessary. However, Duke Energy Carolinas and the Public Staff have agreed to address the appropriate coincident peak in the Company's next DSM/EE rider filing. The Commission finds and concludes that Duke Energy Carolinas and the Public Staff should include information in their filings in the next rider proceeding regarding the appropriate coincident peak to be used to calculate the avoided costs benefits of specific DSM and EE programs.

IT IS, THEREFORE, ORDERED as follows:

1. That the Commission hereby approves the calculation of Rider EE as filed by Duke Energy Carolinas in its Application, and the resulting billing factors as demonstrated in McManeus Exhibit 1, as adjusted to exclude the avoided cost revenue requirement related to the HECR Pilot Program as set forth on Maness Exhibit I filed on June 8, 2011. Such adjusted billing factors shall go into effect for the rate period January 1, 2012 through December 31, 2012, subject to appropriate true-ups in future cost recovery proceedings consistent with the Settlement, Sub 831 Order, and the EM&V Agreement.

2. That Duke Energy Carolinas shall work with the Public Staff to prepare a proposed Notice to Customers of the rate changes approved herein. 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.

3. That the Commission is not making a decision in this docket about whether Duke Energy Carolinas can recover in base rates in North Carolina its reasonable and prudent allocated costs of the South Carolina HECR Pilot Program.

4. That within 30 days of the issuance of this Order Duke Energy Carolinas shall provide the Commission a list of all changes it has made to existing programs and any further proposed changes to programs, with an updated evaluation of cost effectiveness for each program using all four applicable tests, including supporting documentation for its calculations in Docket No. E-7, Sub 831.

5. That within 90 days of the issuance of this Order Duke Energy Carolinas, SACE, and the Public Staff shall file a joint proposal regarding Commission approval of program modifications in Docket No. E-7, Sub 831.

6. That Duke Energy Carolinas shall file annually with each DSM/EE rider application a full list of all changes it has made to existing programs and a proposal for any

further changes to programs. Such list shall also include an updated evaluation of cost effectiveness for each program using all four applicable cost-effectiveness tests and provide supporting documentation for its calculations.

7. That as soon as practicable, but no later than the Company's 2012 DSM/EE cost recovery proceeding, Duke Energy Carolinas shall file for Commission review an exhibit detailing the actual and expected dates when the EM&V for each program or measure will become effective.

8. That in future DSM/EE rider proceedings, Duke Energy Carolinas shall include with its projected schedule for EM&V explanations for delays or changes to its EM&V schedule from the prior proceeding.

9. That in future DSM/EE rider applications, Duke Energy Carolinas shall provide an explanation as to how EM&V results are applied, including:

(a) the date it begins using updated impacts or participation results in its calculations or models;
(b) the programs or measures to which it applies the results;
(c) an analysis of the costs associated with performing additional EM&V work for other measures; and
(d) any other pertinent information regarding the applicability of the EM&V findings to the other CFL measures, including any differences in the characteristics of the targeted participants that would alter savings estimates.

10. That in future DSM/EE rider applications, Duke Energy Carolinas shall explain the effects of persistence and snapback.

11. That in its next DSM/EE rider proceeding Duke Energy Carolinas and the Public Staff shall include information in their filings regarding the appropriate coincident peak to be used to calculate the avoided costs benefits of specific DSM and EE programs.

ISSUED BY ORDER OF THE COMMISSION.
This 8th day of November, 2011.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

fh110711.01

DOCKET NO. E-2, SUB 1000

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc., 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 2010 REPS) COMPLIANCE)

HEARD: Tuesday, September 27, 2011, 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 Lorinzo L. Joyner, William T. Culpepper, III, Susan W. Rabon, ToNola D. Brown-Bland and Lucy T. Allen

APPEARANCES:

For Progress Energy Carolinas, Inc.:

Kendal C. Bowman, Associate General Counsel, Progress Energy Carolinas, Inc., Post Office Box 1551, Raleigh, North Carolina 27602-1551

For the North Carolina Sustainable Energy Association:

Kurt Olson, North Carolina Sustainable Energy Association, 1111 Haynes Street, Suite 109, Raleigh, North Carolina 27628

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

BY THE COMMISSION: On June 3, 2011, Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc. (PEC or the Company), filed its annual Renewable Energy and Energy Efficiency Portfolio Standard (REPS) compliance report pursuant to Commission Rule R8-67(c) together with the supporting testimony of Jay E. Foster, Lead Structuring Analyst – Renewable Energy Portfolio Standards. Also on June 3, 2011, PEC filed an application and the accompanying testimony and exhibits of Jay E. Foster pursuant to G.S. 62-133.8 and Commission Rule R8-67(e), 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 in order to comply with the REPS requirements, G.S. 62-133.8(b), (d), (e) and (f), and to true-up any under-recovery or over-recovery of compliance costs. In its application and pre-filed testimony, PEC sought approval of a rider to recover its reasonable and prudent forecasted REPS costs and an experience modification factor (EMF) rider.

On June 8, 2011, the Commission issued an Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice, in which it set this matter for hearing; established deadlines for the submission of intervention petitions, intervenor testimony, and PEC's rebuttal testimony; required the provision of appropriate public notice; and mandated compliance with certain discovery guidelines.

The intervention of the Public Staff is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e). On June 16, 2011, the North Carolina Sustainable Energy Association (NCSEA) filed a petition to intervene, which was allowed on June 24, 2011. On July 11, 2011, the Carolina Utility Customers Association, Inc. (CUCA), filed a petition to intervene, which was allowed on July 20, 2011. CUCA did not participate in the evidentiary hearing in this matter.

On August 25, 2011, PEC filed affidavits of publication indicating that public notice had been provided in accordance with the Commission's June 8, 2011 procedural order.

On September 7, 2011, the Public Staff filed the direct testimony and exhibits of Jay B. Lucas, Electric Engineer, and the affidavit of Michelle M. Boswell, Staff Accountant. On September 8, 2011, PEC filed the supplemental direct testimony and exhibits of witness Foster.

The case came on for hearing as scheduled on September 27, 2011. The pre-filed testimony and exhibits of PEC witness Foster were received into evidence, and witness Foster presented direct and supplemental testimony on behalf of the Company. The pre-filed testimony and exhibits of Public Staff witness Lucas and the affidavit of witness Boswell were received into evidence, and Public Staff witness Lucas presented direct testimony. No other party presented witnesses, and no public witnesses appeared at the hearing.

On October 20, 2011, the Public Staff and PEC filed a joint proposed order.

Based upon the foregoing, the testimony and exhibits introduced at the hearing, PEC's records in the North Carolina Renewable Energy Tracking System (NC-RETS), and the entire record in this proceeding, the Commission makes the following:

FINDINGS OF FACT

1. PEC 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. PEC is engaged in the business of generating, transmitting, distributing, and selling electric power to the public in North Carolina. PEC is also an electric power supplier as defined in G.S. 62-133.8(a)(3). PEC is lawfully before this Commission based upon its application filed pursuant to G.S. 62-133.8 and Commission Rule R8-67.

2. Beginning in 2010, under the REPS established by G.S. 62-133.8 electric power suppliers must supply at least 0.02% of their previous year's North Carolina retail energy sales by a combination of new solar electric facilities and new metered solar thermal energy facilities. In 2012, this solar requirement increases to 0.07% of the previous year's North Carolina retail sales. Also in 2012, electric power suppliers must generally meet 3% of their previous year's North Carolina retail electric sales by a combination of renewable energy and energy reductions. Beginning in 2012, electric power suppliers are required by G.S. 62-133.8(e) and (f) to procure a certain portion of their renewable energy requirements from electricity generated by poultry and swine waste.

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 of compliance with the REPS. The term "incremental costs," as defined in G.S. 62-133.8(h)(1), includes the costs of renewable energy purchases "that are in excess of the electric power supplier's avoided costs."

4. Under Commission Rule R8-67(e)(2), the total amount of 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.

5. PEC has agreed to provide REPS compliance services, including the procurement of RECs, to the following five electric power suppliers pursuant to G.S. 62-133.8(c)(2)(e): the Towns of Waynesville, Black Creek, Lucama, Sharpsburg and Stantonsburg. These five electric power suppliers are wholesale customers of PEC.

6. PEC and the five electric power suppliers to which PEC is providing compliance services met their 2010 REPS obligations. PEC's 2010 REPS compliance report should be approved.

7. For purposes of PEC's annual rider pursuant to G.S. 62-133.8(h), the test period is August 1, 2010, through March 31, 2011, the update period is April 1, 2011, through July 31, 2011, and the forecast and billing period is December 1, 2011, through November 30, 2012.

8. Pursuant to Commission Rule R8-67(e)(5), PEC is permitted to recover through its REPS EMF rider all reasonable and prudent REPS costs incurred up to 30 days prior to the hearing in this proceeding. Therefore, in this proceeding PEC may incorporate in its determination of its experienced over- or under-recovery of REPS costs those costs incurred through July 31, 2011.

9. PEC has allocated the incremental costs of REPS compliance between its retail customers and the five wholesale customers on an energy basis. This method of allocation is appropriate for use in this proceeding.

10. PEC's incremental costs of retail REPS compliance total $8,686,657 for the test period and $5,794,119 for the update period, a total of $14,480,776. Forecasted incremental costs for retail REPS compliance for the forecast period total $22,237,600.

11. PEC's over-recovery of incremental costs, through its REPS EMF rider, amounts to $636,009 for the test period, and its under-recovery of incremental costs amounts to $1,070,957 for the update period, a net under-recovery of $434,948.

12. The appropriate REPS rider for the residential class per customer account is $0.53 per month. The appropriate REPS rider for the commercial class per customer account is $6.38 per month. The appropriate REPS rider for the industrial class per customer account is $43.16 per month. All of the above numbers are exclusive of the EMF and also exclude the gross receipts tax and regulatory fee.

13. The appropriate EMF rider for the residential class per customer account is $0.01 per month. The appropriate EMF rider for the commercial class per customer account is $0.12 per month. The appropriate EMF rider for the industrial class per customer account is $0.84 per month. All of the above numbers exclude the gross receipts tax and regulatory fee.

14. The appropriate combined REPS and EMF rider, including gross receipts tax and regulatory fee, for the residential class per customer account is $0.56 per month. For the commercial class it is $6.72 per month, and for the industrial class it is $45.52 per month.

15. PEC's combined REPS and REPS EMF rider to be charged to each customer account for the period December 1, 2011, through November 30, 2012, is within the annual cost caps established in G.S. 62-133.8(h).

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-5

These findings of fact are essentially informational, procedural and jurisdictional and are not contested.

G.S. 62-133.8 establishes a REPS for all electric power suppliers in North Carolina. The statute requires, for example, each electric public utility to provide a certain percentage of its North Carolina retail sales from various renewable energy or energy efficiency resources, including the following: (a) generating electric power at a new renewable energy facility; (b) using 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) reducing energy consumption through the implementation of EE measures; (d) purchasing electric power from a new renewable energy facility; (e) purchasing RECs; (f) using electric power that is supplied by a new renewable energy facility or saved due to the implementation of an EE measure that exceeds the requirements of the REPS for any calendar year as a credit towards the requirements of the REPS in the following calendar year; or (g) electricity demand reduction. Each of these measures is subject to certain additional limitations and conditions. In 2012, PEC must generally meet 3% of its previous year's North Carolina retail electric sales by a combination of these measures.

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 0.02% in 2010 and 2011, and 0.07% in 2012.

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. In 2012, the aggregate requirement for swine waste resources is 0.07%. 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 is 170,000 megawatt-hours. 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, PEC's share of the aggregate State set-aside requirements for energy from swine and poultry waste is based on the ratio of its North Carolina retail megawatt-hour sales for the previous year divided by the previous year's total North Carolina retail megawatt-hour sales.

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 rider 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."

PEC's 2010 REPS compliance report states that, pursuant to G.S. 62-133.8(c)(2)(e), the Company provides renewable energy resources and compliance reporting services for the Towns of Waynesville, Black Creek, Lucama, Sharpsburg and Stantonsburg. Available methods of REPS compliance for these municipal electric suppliers are those set forth in G.S. 62-133.8(c).

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence supporting this finding of fact appears in PEC's REPS compliance report and application, the testimony and exhibits of PEC witness Foster, the testimony of Public Staff witness Lucas, and the affidavit of Public Staff witness Boswell. The Commission also takes judicial notice of information contained in NC-RETS.

PEC's 2010 REPS compliance report was admitted into evidence as Exhibit 1 to the testimony of PEC witness Foster. The report states that PEC's 2009 retail sales in North Carolina were 36,388,511 megawatt-hours, making its 2010 REPS obligation 7,278 solar RECs. Witness Foster testified that PEC met its 2010 REPS obligation by transferring 7,278 RECs into the Company's 2010 compliance sub-account in NC-RETS. The compliance report states that the

Town of Waynesville had sales of 90,928 megawatt-hours in 2009, and that its 2010 REPS obligation is 19 solar RECs. The report states further that the four other wholesale customers' 2009 retail sales in North Carolina were 69,006 megawatt-hours in aggregate, and that their 2010 REPS obligation is 14 solar RECs. Witness Foster testified that the 2010 solar requirement for the five wholesale customers is 33 RECs, and that the solar RECs required to meet the 2010 requirement had been transferred into compliance sub-accounts in NC-RETS. The Commission notes that the retail sales and REC numbers in PEC's compliance report and witness Foster's testimony are consistent with the data in NC-RETS.

Public Staff witness Lucas testified that he reviewed PEC's compliance report and found that it meets the requirements of Commission Rule R8-67(c) for both PEC and the wholesale customers. Witness Lucas also testified that PEC had limited its use of out-of-state RECs to 25% of its compliance obligation, as required by G.S. 62-133.8(b)(2)(e).

PEC witness Foster described PEC's efforts to comply with the renewable energy requirements of G.S. 62-133.8 in his direct testimony. He explained that in November 2007 and 2008, PEC issued broad requests for proposals (RFPs) for renewable energy. In November 2009, PEC issued a wood biomass specific RFP. Additionally, PEC currently maintains an open RFP with flexible parameters that can be changed depending on conditions and needs. Through this process, PEC received a significant number of proposals using a variety of renewable resources. Proposals and bids received were evaluated against each other, the market, PEC's renewable energy needs and the potential impacts to the annual cost cap to select projects that provide the most cost-effective means for meeting the REPS requirement. Thus far, PEC has executed more than 50 contracts, and additional contracts are in various stages of negotiation.

Witness Foster testified that PEC launched the SunSense Commercial program in July 2009 to meet the solar set-aside requirement. This program encourages small scale photovoltaic (PV) or solar thermal installations that complement larger solar projects within PEC's renewable portfolio. The solar PV program offers a standard payment for eligible rooftop mounted solar PV systems, and it has an annual program limit of 5 megawatts. Since program inception PEC has executed over 20 contracts. Additionally, PEC launched the SunSense Residential program to encourage small scale PV installations up to 10 kilowatts in size. These projects will receive an up-front rebate towards the installation cost of the system, and a monthly bill credit as long as the system remains in place. The current annual program participation limit is one megawatt per year, and to date PEC has executed more than 15 contracts.

According to witness Foster, due to the availability of renewable resources in other areas of the country, as well as the REC requirements in other regions, out-of-state RECs can be acquired at a significantly lower price than those generated by resources in North Carolina. To meet the REPS requirement in the most cost-effective manner, PEC foresees purchasing up to 25% of its REPS requirement through out-of-state RECs.

With regard to the purchase of renewable energy generated from poultry and swine waste, witness Foster testified that PEC and the State's other electric power suppliers issued a state-wide RFP for swine waste generation that allowed for the joint negotiation and procurement of swine waste resources. As a result of this RFP, PEC has signed two contracts for approximately 4 megawatts from swine waste-to-energy resources. PEC remains in negotiations with two other companies for swine waste-to-energy resources. In April 2011, PEC executed a 36-megawatt contract with a poultry waste-to-energy facility.

No other party presented any evidence on this issue. Thus the Commission finds and concludes that PEC and the five wholesale customers have fully complied with the requirements of the REPS for 2010, and that PEC's 2010 REPS compliance report should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 7-8

These findings of fact are essentially informational, jurisdictional and procedural in nature and are not contested.

Commission Rule R8-67(e) provides that the Commission shall schedule an annual public hearing to review an electric public utility's REPS compliance costs. Rule R8-67(e)(4) further provides that the test period for each utility shall be the same as the test period for purposes of Rule R8-55. Rule R8-55 provides that PEC's test period is the twelve months ending March 31 of each year. Therefore, PEC proposed a test year for its REPS cost recovery proceeding of the twelve months ending March 31, 2011.

Commission Rule R8-67(e)(5) provides that upon request of an electric public utility the Commission shall also incorporate in its determination of a utility's REPS EMF rider its experienced over- or under-recovery of incremental REPS costs up to 30 days prior to the hearing, provided that the reasonableness and prudence of these costs shall be subject to review in the utility's next annual REPS cost recovery hearing. Given that PEC's annual REPS cost recovery hearing occurs in September, PEC is entitled to incorporate in its determination of its under- or over-recovery of incremental REPS costs those costs incurred through July 31 of each year, to the extent not recovered in other proceedings. This period, from April 1 through July 31, 2011, is referred to as the "update period."

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 1001, and in this proceeding, PEC proposed, without objection from any party, that its rate adjustments take effect on December 1, 2011, and remain in effect for a 12-month period. This period is referred to as the "forecast period."

The test period proposed by PEC is supported by the Public Staff and is consistent with Commission Rules R8-67(e) and R8-55. The test year proposed by PEC was not challenged by any party, and the Commission concludes that the test year appropriate for use in this proceeding is the twelve months ending March 31, 2011, and that PEC is entitled to include its experienced over- and under-recovery of incremental REPS compliance costs incurred through July 31, 2011.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The evidence for this finding of fact can be found in the testimony of PEC witness Foster and Public Staff witness Lucas, and in the affidavit of Public Staff witness Boswell.

PEC witness Foster stated that, pursuant to G.S. 62-133.8(c)(2)(e), PEC agreed to procure RECs for the five wholesale customers and that PEC proposed to allocate all of its incremental REPS compliance costs among its retail customers and the wholesale customers on an energy basis. He noted that the percentage allocable to the wholesale customers during the test period (August 2010 - March 2011) was 0.45%. For the update and forecast periods, the percentages allocated to the wholesale customers for incremental REPS compliance costs are 0.44% and 0.42%, respectively.

Public Staff witness Boswell stated in her affidavit that the Public Staff had some concerns about the allocations of costs and RECs among PEC's retail customers and the wholesale customers. She noted that the Public Staff and PEC had discussed the issue and agreed further evaluation of this issue was necessary. Witness Boswell stated that the Public Staff would continue to review the issue.

Public Staff witness Lucas testified that he did not have any concerns with the cost allocations for the EMF rider being established in this proceeding.

No party took issue with PEC's purchase of RECs for the wholesale customers or with the proposed REC allocation. As the Commission noted in PEC's 2009 REPS proceeding, Docket No. E-2, Sub 948, RECs funded solely by PEC's retail customers should be used solely for PEC's REPS obligations. Similarly, RECs associated with EE savings should be used exclusively for PEC's REPS compliance because no portion of the costs of EE measures are being allocated to and recovered from the wholesale customers.

Based on the testimony of witnesses Lucas and Foster and the affidavit of witness Boswell, the Commission finds and concludes that the allocation of incremental REPS costs among retail and wholesale customers in PEC's proposed REPS and EMF rider is appropriate. The Commission might re-visit the issue of cost allocations for the REPS EMF and REPS riders established in PEC's next annual REPS rider proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 10-14

The evidence supporting these findings of fact appears in PEC's application, the testimony and exhibits of PEC witness Foster, the testimony of Public Staff witness Lucas, and the affidavit of Public Staff witness Boswell.

PEC witness Foster described PEC's efforts to comply with the renewable energy requirements of G.S. 62-133.8 in his testimony, and he described PEC's efforts more fully in PEC's REPS compliance report.

PEC witness Foster testified that in addition to the costs of purchases of renewable power and RECs, PEC seeks to recover the incremental labor costs associated with REPS compliance activities, costs for research and development activities to further emerging renewable technologies, and incremental costs for implementation and operation of NC-RETS.

In regard to the methodology used by PEC to calculate the incremental costs associated with its purchases from renewable energy facilities, witness Foster explained that the total deferred and projected incremental costs to comply with G.S. 62-133.8 were summed for the time periods required. Each customer class was then allocated its share of the deferred and projected incremental costs, as shown in Foster Supplemental Exhibit No. 3, based on its pro-rata share of the customer cost caps defined in G.S. 62-133.8(h)(4). In 2012, the cost caps for residential, commercial and industrial customers increase. Therefore, the cost caps for the December 2011 to November 2012 period are calculated using the cost caps for 2011 for one month (December 2011), and the cost caps for 2012 for 11 months, for a 12-month total. The proration formula is the total dollars available for the 12 months from December 2011 through November 2012 from a specific customer class, divided by the total dollars available for the 12 months from December 2011 through November 2012 from all customer classes. The cost allocated to each customer class is then divided by the estimated average number of accounts within each customer class during the twelve months ending December 2011, to arrive at the total annual cost to be recovered from each account. The monthly REPS rider for each customer class is then one-twelfth of the total annual cost.

Witness Foster's exhibits show that PEC's incremental costs of retail REPS compliance are \$8,686,657 for the test period and \$5,794,119 for the update period for a total of \$14,480,776. The forecasted incremental costs for REPS compliance for the forecast or billing period amount to a total of \$22,237,600. Witness Foster's exhibits also show that PEC's over-recovery of incremental costs, through REPS EMF riders, amounts to \$636,009 for the test period, and its under-recovery amounts to \$1,070,957 for the update period, a net under-recovery of \$434,948.

Witness Foster calculated the monthly REPS rider amounts of \$0.53 for the residential class, \$6.38 for the commercial class and \$43.16 for the industrial class. Witness Foster also calculated the monthly REPS EMF rider amounts of \$0.01 for the residential class, \$0.12 for the commercial class, and \$0.84 for the industrial class. Additionally, the combined monthly REPS and REPS EMF riders, excluding the gross receipts tax and the regulatory fee, are \$0.54 for the residential class, \$6.50 for the commercial class and \$44.00 for the industrial class. Including gross receipts tax and the regulatory fee, the combined monthly REPS and REPS EMF riders are \$0.56 for the residential class, \$6.72 for the commercial class, and \$45.52 for the industrial class.

Public Staff witnesses Lucas and Boswell stated that they had reviewed and analyzed the REPS incremental costs for which PEC is requesting recovery in this proceeding. Witness Boswell agreed with PEC's proposed REPS EMF rider. Witness Lucas recommended that the Commission approve PEC's EMF and REPS riders as described in witness Foster's supplemental testimony and revised exhibits. No other party presented any evidence regarding PEC's REPS costs. Therefore, the Commission approves PEC's REPS incremental costs for the test period as reasonable and prudent. Commission Rule R8-67(e)(5) provides that the reasonableness and prudence of the costs incurred during the update period shall be subject to review in the utility's next annual REPS cost recovery hearing.

Based on the testimony of witnesses Foster and Lucas, and the affidavit of witness Boswell, the Commission finds and concludes that the REPS and REPS EMF riders proposed by PEC are reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The evidence for this finding of fact is found in the testimony and exhibits of PEC witness Foster, the testimony of Public Staff witness Lucas, and the affidavit of Public Staff witness Boswell.

G.S. 62-133.8(h)(4) established the annual cost caps for REPS and REPS EMF riders. Foster Supplemental Exhibit No. 3 demonstrates that the forecast period spans 2011 and 2012, and that each of those years has a different cost cap. The annual per-account cost caps are $10, $50 and $500 for the residential, commercial and industrial customer classes, respectively, through 2011. Starting in 2012, the annual per account cost caps increase to $12, $150 and $1,000 for the residential, commercial and industrial customer classes, respectively. As discussed above, the Commission finds and concludes that the appropriate combined monthly REPS and REPS EMF riders are $0.56 for the residential class, $6.72 for the commercial class and $45.52 for the industrial class, including gross receipts tax and regulatory fee. These riders will be in effect for a rate period that includes one month in 2011 and 11 months in 2012. On an annualized basis, these amounts equate to $6.72 for the residential class, $80.64 for the commercial class, and $546.24 for the industrial class, amounts that are well below the increased cost caps that take effect in 2012.[1]

Therefore, the Commission finds and concludes that PEC's proposed REPS and REPS EMF riders, in total and including gross receipts tax and regulatory fee, do not exceed the annual cost caps established in G.S. 62-133.8(h)(4).

IT IS, THEREFORE, ORDERED as follows:

1. That PEC shall establish a REPS Rider as described herein, in the amounts approved herein, and this rider shall remain in effect for a 12-month period beginning on December 1, 2011, and expiring on November 30, 2012;

2. That PEC shall establish a REPS EMF Rider as described herein, in the amounts approved herein, and this rider shall remain in effect for a 12-month period beginning on December 1, 2011, and expiring on November 30, 2012;

[1] PEC's calendar year combined EMF and REPS rider charges for 2011 are similarly below the 2011 cost caps, with residential customers paying $6.94, commercial customers paying $38.62, and industrial customers paying $363.75.

3. That PEC shall file appropriate rate schedules and riders with the Commission in order to implement the provisions of this Order not later than seven (7) working days from the date of this Order;

4. That PEC shall work with the Public Staff to prepare a joint proposed Notice to Customers giving notice of the rate changes ordered by the Commission in Docket No. E-2, Subs 1000, 1001 and 1002, and PEC shall file such proposed notice for Commission approval as soon as practicable; and

5. That PEC's 2010 REPS compliance report is approved.

ISSUED BY ORDER OF THE COMMISSION.
This the 10th day of November, 2011.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

kj111011.01

DOCKET NO. E-2, SUB 1002

In the Matter of	)	
Application by Carolina Power & Light Company,	)	ORDER APPROVING DSM/EE
d/b/a Progress Energy Carolinas, Inc. for Approval of	)	RIDER AND REQUIRING FILING
Demand-Side Management and Energy Efficiency	)	OF PROPOSED CUSTOMER
Cost Recovery Rider Pursuant to G.S. 62-133.9 and	)	NOTICE
Commission Rule R8-69	)	

HEARD IN: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina on Tuesday, September 27, 2011, at 10:20 a.m.

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

APPEARANCES: .

For Progress Energy Carolinas, Inc.:

Kendal C. Bowman, Associate General Counsel, Progress Energy Carolinas, Inc., Post Office Box 1551, PEB 17B2, Raleigh, North Carolina 27602-1551

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: G.S. 62-133.9(d) authorizes the North Carolina Utilities Commission (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 and 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.

Docket No. E-2, Sub 1002

Pursuant to G.S. 62-133.9 and Commission Rule R8-69, on June 3, 2011, Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc. (PEC or Company), filed an application and the associated direct testimony of Robert P. Evans and Julie Hans 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, net lost revenues, and an additional incentive. In addition, PEC asked for approval of a DSM/EE EMF rider and, pursuant to Commission Rule R8-69(b)(2), PEC also requested recovery through the DSM/EE EMF rider of its costs, including carrying costs, net lost revenues, and an additional incentive, incurred up to 30 days prior to the hearing in this proceeding.

On June 7, 2011, PEC filed its statement of verification for the prefiled testimony of Julie Hans which was inadvertently excluded from the Company's June 3, 2011 filing.

On June 8, 2011, the Commission issued an Order scheduling a public hearing in this matter on September 27, 2011, immediately following the 9:30 a.m. hearing in Docket No. E-2, Sub 1001, establishing discovery guidelines, providing for intervention and testimony by other parties, and requiring public notice. On August 25, 2011, PEC filed its affidavits of publication indicating that the Company had provided notice in newspapers of general circulation as required by the Commission's June 8, 2011 Order.

On June 21, 2011, PEC filed a revised Appendix D to its Exhibit No. 1 included in its application filed on June 3, 2011. In its filing, PEC stated that due to measurement and verification related adjustments and other factors impacting both the test period and prior periods, the original Appendix D was not necessarily representative of test period activities. PEC stated that the revised Appendix D was based solely on test period participation levels and impacts.

The intervention of the Public Staff is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e). On July 11, 2011, Carolina Utility Customers Association, Inc. (CUCA) filed a petition to intervene, which was granted by Commission Order issued July 20, 2011. On September 6, 2011, the Southern Alliance for Clean Energy (SACE) filed a Statement of Position Letter.[1]

On August 23, 2011, PEC filed the supplemental direct testimony and exhibits of witness Evans. On September 2, 2011, the Public Staff filed a motion for an extension of time to file its direct testimony. By Order issued September 6, 2011, the Commission granted the Public Staff's motion. On September 9, 2011, the Public Staff filed the affidavits of Michael C. Maness and Jack L. Floyd.

On September 27, 2011, the hearing was held as scheduled. The Applicant stated that it agreed with the recommendations of the Public Staff; consequently, PEC and the Public Staff agreed to accept all prefiled testimony, exhibits, and affidavits into evidence and to waive cross-examination of the witnesses. PEC stated that CUCA, who is an intervenor in this proceeding, was not planning to attend the hearing. Based upon such stipulation, the Commission received into evidence the prefiled testimony and exhibits of PEC witnesses Evans and Hans and the affidavits of Michael C. Maness and Jack L. Floyd, as if given orally from the witness stand. No public witnesses appeared at the hearing. On October 20, 2011, PEC and the Public Staff filed a Joint Proposed Order.

Other Pertinent Docket Nos. E-2, Sub 931 and Sub 926

On June 15, 2009, in Docket No. E-2, Sub 931, the Commission issued an Order Approving Agreement and Stipulation of Partial Settlement, Subject to Certain Commission-Required Modifications in PEC's first DSM/EE rider proceeding (Sub 931 Order). In that Order, the Commission approved, with certain modifications, an Agreement and Stipulation of Partial Settlement (Stipulation), between PEC, the Public Staff, and Wal-Mart Stores East, LP and Sam's East, Inc. setting forth the terms and conditions for approval of DSM/EE measures and the annual DSM/EE rider proceedings pursuant to G.S. 62-133.9 and Commission Rules R8-68 and R8-69. Such Stipulation included a Cost Recovery and Incentive Mechanism for Demand-Side Management and Energy Efficiency Programs (Mechanism), which was modified by the Commission in its Sub 931 Order, to allow PEC to recover all reasonable and prudent costs incurred for adopting and implementing new DSM and EE measures in accordance with G.S. 62-133.9, Commission Rules R8-68 and R8-69, and the additional principles set forth in the Mechanism.

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[1] In its Statement of Position Letter, SACE stated that it was not filing for intervention in the present proceeding because it did not anticipate participating beyond submitting such statement. Further, SACE noted that it was aware of the limited manner in which statement of position letters are considered by the Commission.

ELECTRIC – RATE SCHEDULES/RIDERS/SERVICE RULES AND REGULATIONS

On July 13, 2009, PEC filed a Motion for Reconsideration and Stay regarding certain decisions made by the Commission in Docket Nos. E-2, Sub 926[1] and Sub 931.[2] The request for reconsideration filed by PEC involved, among other things, the Commission's decision that industrial and large commercial customers may not opt-out of cost recovery with respect to PEC's Distribution System Demand Response (DSDR) Program. After receiving comments and reply comments, on August 24, 2009, the Commission issued an Order on Motion for Full Commission Review setting the matter for oral argument before the full Commission on September 16, 2009.

On November 25, 2009, in Docket No. E-2, Sub 931, the Commission issued an Order Granting Motions for Reconsideration in Part determining, among other things, that industrial and large commercial customers that opt out of PEC's DSM and EE programs will not be charged, via a rider, for the DSDR program.

In the present proceeding, based upon PEC's verified application, the affidavits and the testimony and exhibits received into evidence at the hearing, and the record as a whole, the Commission now makes the following

FINDINGS OF FACT

1. PEC 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 and South Carolina, and is subject to the jurisdiction of the Commission as a public utility. PEC is lawfully before this Commission based upon its application filed pursuant to G.S. 62-133.9 and Commission Rule R8-69.

2. The test period for purposes of this proceeding is the 12-month period April 1, 2010 through March 31, 2011.

3. The rate period for the purposes of this proceeding is the 12-month period December 1, 2011 through November 30, 2012.

4. Pursuant to Commission Rule R8-69(b)(2), PEC is permitted to include in its DSM/EE EMF rider its over- or under-recovery of DSM/EE costs, including net lost revenues and an additional incentive, experienced up to 30 days prior to the hearing. In this proceeding, such period is referred to as the prospective period, and is April 1, 2011 through July 31, 2011.

5. For purposes of this proceeding, PEC has requested the recovery of costs and incentives, where applicable, related to the following DSM/EE programs: Distribution System Demand Response (DSDR); EnergyWise™; Commercial, Industrial, and Governmental (CIG) Demand Response; Residential Home Advantage; Residential Home Energy Improvement

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[1] Docket No. E-2, Sub 926 is PEC's application for approval of its proposed Distribution System Demand Response Program.

[2] Motions for reconsideration were also filed by three intervenors (CUCA, Wal-Mart, and CIGFUR II) in those dockets.

Program (RHEIP); Residential Low Income-Neighborhood Energy Saver (NES); CIG EE; Residential Lighting; Residential Energy Efficiency Benchmarking; Residential Appliance Recycling; Residential Solar Water Heater Pilot; and Compact Fluorescent Light (CFL) Pilot.

6. PEC also requested recovery of incremental A&G expenses not directly related to specific DSM or EE programs. The incremental costs are $2,116,426 for the test period; $670,307 for the prospective period; and $2,320,405 for the rate period. Additionally, as requested by the Commission in the Sub 951 Order, PEC has provided data regarding the reach and extent of its general DSM/EE education and awareness (GEA) initiatives. It is appropriate for PEC to recover these incremental A&G costs, subject to further review in PEC's future DSM/EE rider proceedings, to the extent allowed in the Stipulation and Mechanism.[1]

7. In the present proceeding, PEC provided information regarding the appropriateness of incorporating GEA costs (and the associated A&G costs) into the cost-effectiveness tests and evaluations of PEC's currently approved programs and all future programs, as requested by the Commission in its Order Approving PEC's present DSM/EE rider, issued on November 17, 2010 in Docket No. E-2, Sub 977. It is appropriate for the impact of indirect GEA and other indirect A&G costs to be taken into account when calculating the cost-effectiveness of PEC's DSM/EE portfolio, as opposed to such impact being employed when calculating the cost-effectiveness of individual programs.

8. PEC requested the recovery of net lost revenues and program incentives in the amount of $7,123,294 for the test period, $3,057,357 for the prospective period, and $19,294,870 for the rate period. PEC's proposed recovery of net lost revenues and program incentives are consistent with the Sub 931 Order, as modified by the Commission's November 25, 2009 Order Granting Motions for Reconsideration in Part, in the same docket, and are appropriate for recovery in this proceeding, subject to further review in PEC's future DSM/EE rider proceedings, to the extent allowed in the Stipulation and Mechanism.

9. For purposes of determining the DSM/EE EMF rider, PEC's reasonable and prudent North Carolina retail total amount for the test period consisting of amortized DSM/EE operations and maintenance (O&M) costs, capital costs, taxes, amortized incremental A&G costs, carrying charges, net lost revenues, and program incentives is $31,416,882. Subject to review in PEC's next annual DSM/EE rider proceeding, PEC's North Carolina retail total DSM/EE program amount for the prospective period consisting of amortized O&M costs, capital costs, taxes, amortized incremental A&G costs, carrying charges, and net lost revenues is $11,607,966. The sum of these two amounts is $43,024,848 and it should be reduced by $6,047,851 to remove the revenue requirement for the period April 1, 2010 to July 31, 2010, to avoid double counting amounts which were recognized in Docket No. E-2, Sub 977. The resulting amount of $36,976,997 is the appropriate amount to use to develop the DSM/EE EMF revenue requirement.

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[1] The Stipulation and Mechanism was approved by the Commission on June 15, 2009, in its Order Approving Agreement and Stipulation of Partial Settlement, Subject to Certain Commission-Required Modifications, in Docket No. E-2, Sub 931 (Sub 931 Order), and modified by the Commission's November 25, 2009 Order Granting Motions for Reconsideration in Part, in that same docket.

10. The appropriate DSM/EE EMF riders for the Residential and General Service rate classes, *excluding* gross receipts tax (GRT) and the North Carolina regulatory fee (NCRF) are increments of 0.006 cents per kilowatt-hour (kWh) and 0.001 cents per kWh, respectively. The appropriate DSM/EE EMF rider for the Lighting rate class, excluding GRT and the NCRF is a decrement of 0.009 cents per kWh. The appropriate DSM/EE EMF riders *including* GRT and the NCRF are, for the Residential and General Service rate classes, increments of 0.006 cents per kWh and 0.001 cents per kWh, respectively, and, for the Lighting rate class, a decrement of 0.009 cents per kWh.[1]

11. For purposes of determining the DSM/EE rider, PEC's reasonable and appropriate estimate of its North Carolina retail total DSM/EE program amounts for the rate period consisting of amortized O&M costs, capital costs, taxes, amortized incremental A&G costs, carrying charges, net lost revenues, and program incentives is $65,354,771. This is the appropriate amount to use to develop the forward-looking DSM/EE revenue requirement.

12. The appropriate forward-looking DSM/EE riders to be charged by PEC during the rate period for the Residential, General Service, and Lighting rate classes, *excluding* GRT and the NCRF, are increments of 0.290 cents per kWh, 0.185 cents per kWh, and 0.094 cents per kWh, respectively. The appropriate DSM/EE riders *including* GRT and the NCRF for the Residential, General Service, and Lighting classes are increments of 0.300 cents per kWh, 0.191 cents per kWh, and 0.097 cents per kWh, respectively.

13. While the initial evaluation, measurement, and verification (EM&V) analyses and reports prepared by PEC are adequate, refinements and improvements are appropriate for future reports.

14. PEC's requested true-up of its RHEIP for Vintage Year 2009 activities properly recognizes the Program's independent EM&V results for that period and is in compliance with the governing provisions contained in the Commission's Sub 931 Order.

15. Pursuant to Paragraph No. 2.D. of the Stipulation and Paragraph No. 45 of the Mechanism, as approved by the Commission in its Sub 931 Order and modified by the Commission in its November 25, 2009 Order Granting Motions for Reconsideration in Part, in that same docket, it will be appropriate for the Public Staff to initiate a formal review of such Mechanism not later than June 1, 2012. Such review should specifically address whether the incentives in the Commission-approved Mechanism are producing significant DSM and EE results; whether the customer rate impacts from the DSM/EE rider are reasonable and appropriate; whether overall portfolio performance targets should be adopted; and any other relevant issues that may arise during the review process.

[1] GRT and NCRF are calculated at the combined rate of 3.34%; however, when rounded to three decimal places, the DSM/EE EMF riders excluding and including these items are the same.

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

These findings of fact are essentially informational, procedural, and jurisdictional in nature and are uncontroverted. The rate period, test period, and prospective period proposed by PEC are supported by the Public Staff and are consistent with Commission Rule R8-69.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence for this finding of fact can be found in PEC's application; in the testimony and exhibits of PEC witness Evans; in the affidavit of Public Staff witness Floyd; and in various Commission orders.

In direct testimony filed on June 3, 2011, witness Evans testified that PEC is requesting the recovery of costs associated with the following DSM/EE programs: DSDR; EnergyWise™; CIG Demand Response; Residential Home Advantage; Residential Home Energy Improvement; Residential Low Income-NES; CIG Energy Efficiency; Residential Lighting; Residential Energy Efficiency Benchmarking; Residential Appliance Recycling; Residential Solar Water Heater Pilot; and CFL Pilot. Further, witness Evans stated that PEC is not requesting net lost revenues for its Residential Solar Water Heater Pilot program[1] and that net lost revenue for event-driven measures has only been requested in association with actual deployments, not for forecasted periods which cannot be accurately predicted in advance.[2]

In his affidavit, Public Staff witness Floyd also listed the DSM/EE programs for which PEC is seeking a cost recovery rider and noted that each of these programs has previously received Commission approval as a new DSM or EE program and is eligible for cost recovery in this proceeding under G.S. 62-133.9. The Commission approved the DSM/EE programs in which cost recovery is requested in this proceeding in Docket Nos. E-2, Subs 908, 926, 927, 928, 935, 936, 937, 938, 950, 952, 953, and 970.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence for this finding of fact can be found in PEC's application; in the testimony of PEC witness Hans; in the testimony and exhibits of PEC witness Evans; and in the affidavit of Public Staff witness Floyd.

PEC witness Hans testified that during the test period PEC's general education and awareness expenses decreased 12.3% from the prior test period and that PEC implemented new tactics for reaching customers, including online advertising and social media outreach. PEC created a Twitter profile called "Energy Advisors" to help educate customers about energy

[1] Ordering Paragraph No. 3 of the Commission's April 21, 2009 Order Granting Program Approval in Docket No. E-2, Subs 928, 938, and 937, states that PEC will not be allowed to recover net lost revenues or other utility incentives for its Residential Solar Water Heater Pilot Program.

[2] In its November 25, 2009 Order Concerning DSM/EE Rider and DSM/EE EMF Rider issued in Docket No. E-2, Sub 951, the Commission approved PEC's request to estimate its net lost revenues for event-driven DSM and EE measures on the basis of actual events as opposed to estimates of such events.

efficiency and the programs available for customers. Over 220 tweets have been sent out with almost 500 followers ranging from customers to industry experts. PEC has published General Awareness Advertising in 14 different publications in PEC's service territory. PEC also offers a free Customized Home Energy Report (CHER) tool to help customers identify home energy improvements and other actions that can be taken to save money on electric bills. More than 837,000 customers received a bill insert from PEC directing them to visit the CHER website and to complete the survey. As of March 2011, more than 21,000 customers had completed the CHER questionnaire and were provided information on specific programs and rebates. Additionally, witness Hans observed that PEC's Save the Watts website received more than 200,000 first time and repeat visits during the test year. PEC representatives also attended 28 community events across PEC's service territory to educate customers about PEC's EE programs and to share energy savings tips. More than 5,000 fliers containing low-cost/no-cost solutions and materials associated with energy efficiency rebate programs were distributed at these events.

PEC witness Evans stated that the common A&G costs associated with the programs provide a system benefit in support of both EE and DSM programs. Witness Evans explained that since A&G costs relate to both EE and DSM programs, A&G amounts are included in both categories. Further, witness Evans explained that the division of these costs into either the EE or DSM category is based upon the percentage of each type of expenditure anticipated during the next forecast calendar year. For example, if 30% of these costs in the forecast period are EE-related, then 30% of the A&G costs will be considered as EE-related costs for allocation purposes. Witness Evans submitted that the use of a forecast period recognizes the types of new programs PEC will offer in the immediate future that will be supported by these administrative costs. Witness Evans stated that the assignment of A&G costs as either EE- or DSM-related is reviewed annually each May based upon forecasted costs for the next calendar year. Witness Evans explained that the A&G costs in this proceeding have been assigned to these categories based upon forecasted DSM and EE costs for 2012. Further, PEC witness Evans stated that, due to its scope and nature, DSDR costs, including A&G, are being tracked separately. PEC's incremental A&G costs were presented on PEC witness Evans Exhibit No. 1. The incremental A&G costs are $2,116,426 for the test period, $670,307 for the prospective period, and $2,320,405 for the rate period.

The incremental GEA costs, which are a part of the aforementioned A&G costs, were identified on Page 5 of PEC witness Evans' direct testimony. These costs are $728,976 for the test period, $324,514 for the prospective period, and $808,451 for the rate period.

Public Staff witness Floyd stated in his affidavit that PEC's expenditures for its GEA initiatives were reasonable. Witness Floyd recommended that PEC continue to provide a list of GEA initiatives and the volume of activity associated with each initiative during the test year in future DSM/EE rider proceedings. He also recommended that PEC be required to investigate the feasibility and cost of conducting a market survey to assess the effectiveness of PEC's GEA activities in terms of market transformation instead of program impact.

No party opposed the recovery of PEC's reasonable and prudent GEA expenditures described in witness Floyd's affidavit and in PEC's testimony. The Commission finds and concludes that it is appropriate for PEC to be allowed to recover its reasonable and prudent incremental A&G costs, including its incremental GEA expenditures, as set forth hereinabove. Such costs will be subject to further review in PEC's future DSM/EE rider proceedings, to the extent allowed in the Commission-modified Stipulation and Mechanism. Further, the Commission concludes that PEC should continue to provide a list of GEA initiatives and the volume of activity associated with each initiative during the test year in future DSM/EE rider proceedings and investigate the feasibility and cost of conducting a market survey to assess the effectiveness of PEC's GEA activities as soon as practicable.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence for this finding of fact can be found in the testimony of PEC witness Evans and in the affidavit of Public Staff witness Floyd.

PEC witness Evans testified that indirect GEA costs and A&G costs primarily represent common or shared costs that cannot be directly assigned to an individual program, and that these costs support all programs and offerings and only exist at the portfolio level. Given this, and other rationale, witness Evans indicated that these costs should be accounted for at the portfolio level.

Public Staff witness Floyd concurred with witness Evans regarding the inclusion of indirect costs in the evaluation of the cost-effectiveness of the entire portfolio of DSM/EE programs. Witness Floyd observed that if a portion of indirect costs were allocated to a particular program, those costs might have no relation to or bearing on the actual cost-effectiveness of the program and yet would lower the result of the cost-effectiveness calculation.

Based upon the testimony of PEC witness Evans and the affidavit of Public Staff witness Floyd, the Commission finds and concludes that it is appropriate for PEC to continue to consider the impact of indirect GEA and other indirect A&G costs on the cost-effectiveness of PEC's DSM and EE programs at the portfolio level. Accordingly, the Commission finds and concludes that PEC should not be required to recognize indirect costs in its determination of the cost-effectiveness of individual programs.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 8 THROUGH 12

The evidence for these findings can be found in the testimony and exhibits of PEC witness Evans and the affidavits of Public Staff witnesses Floyd and Maness.

PEC witness Evans calculated PEC's North Carolina retail test period DSM/EE net lost revenues and program incentives to be $7,123,294. He calculated PEC's North Carolina retail prospective period DSM/EE net lost revenues and program incentives (net of the prior prospective period total) to be $3,057,357. He also calculated PEC's North Carolina retail rate period DSM/EE net lost revenues and program incentives to be $19,294,870.

Further, PEC witness Evans calculated PEC's North Carolina retail total amount for the test period, consisting of its amortized DSM/EE O&M costs, capital costs, taxes, amortized incremental A&G costs, carrying charges, net lost revenues, and program incentives to be $31,416,882. For the prospective period, witness Evans calculated the total to be $11,607,966. Witness Evans took the sum of these amounts and reduced it by $6,047,851 to remove the revenue requirement for the period April 1, 2010 to July 31, 2010, to avoid double counting amounts, as provided by the Sub 977 Order. According to witness Evans the resulting amount is $36,976,997; and this amount is appropriate to use to develop the DSM/EE EMF revenue requirement. Further, witness Evans estimated PEC's North Carolina retail DSM/EE program rate period amounts, consisting of its amortized O&M costs, amortized incremental A&G costs, carrying charges, net lost revenues, and program incentives to be $65,354,771.

PEC witness Evans calculated the DSM/EE EMF riders for the Residential and General Service rate classes for the rate period to be increments of 0.006 cents per kWh and 0.001 cents per kWh, respectively, and a decrement of 0.009 cents per kWh for the Lighting rate class, *excluding* GRT and the NCTF. He calculated these DSM/EE EMF riders, *including* GRT and the NCRF, to be increments of 0.006 cents per kWh and 0.001 cents per kWh, respectively, for the Residential and General Service rate classes, and a decrement of 0.009 cents per kWh for the Lighting rate class. He also calculated the forward-looking DSM/EE rates for the Residential, General Service, and Lighting rate classes for the rate period to be increments of 0.290 cents per kWh, 0.185 cents per kWh, and 0.094 cents per kWh, respectively, *excluding* GRT and the NCRF, and 0.300 cents per kWh, 0.191 cents per kWh, and 0.097 cents per kWh, *including* GRT and the NCRF.

Public Staff witness Maness stated that the method by which PEC has calculated its proposed rates in this proceeding is the Mechanism, approved by the Commission in the Sub 931 Order, and modified by the Commission's November 25, 2009 Order Granting Motions for Reconsideration in Part, in that same docket.

According to witness Maness, the overall focus of the Public Staff's investigation of PEC's filing in this proceeding was whether the proposed DSM/EE riders were calculated in accordance with the Mechanism and otherwise adhered to sound ratemaking concepts and principles. Witness Maness stated that the Public Staff's investigation included a review of the Company's filing and relevant prior Commission proceedings and orders, and the selection and review of a sample of source documentation for test year costs included by the Company for recovery. Witness Maness explained that the Public Staff's investigation required the review of responses to written and verbal data requests, discussions with Company personnel, and site visits to the Company's offices to review documentation.

Witness Maness observed that Public Staff's investigation, including its sampling procedure, was concentrated primarily on costs and incentives related to the April 2010 – March 2011 test period, which are to be included in the DSM/EE EMF riders approved in this proceeding, with a more general review of the estimated costs and incentives included in the rate period (December 2011–November 2012) component of the riders. Actual costs and incentives applicable to the rate period, as well as costs and incentives applicable to the April 2011–July 2011 "prospective" period, which are also included in the DSM/EE EMF riders, will be subject to detailed review in future DSM/EE cost recovery proceedings.

Witness Maness noted that his investigation of PEC's filing indicates that the Company generally has calculated the proposed riders in accordance with the methods set forth in the approved Mechanism for recovery of costs, net lost revenues, and the additional incentive, the program performance incentive (PPI).

Public Staff witness Floyd also reviewed PEC's rider calculations and inputs. Witness Floyd confirmed that PEC allocated DSM- and EE-related costs to its North Carolina and South Carolina retail jurisdictions on the basis of retail peak demand and energy sales, respectively. Witness Floyd stated that PEC's calculation of its DSM/EE and DSM/EE EMF riders included allocations of program costs, net lost revenues, and PPIs related to the specific customer classes that the programs were designed to serve. According to witness Floyd, costs related to the DSDR EE program have been allocated to all classes on the basis of retail energy sales. Further, energy sales related to customers who have opted-out of participation in PEC's DSM and EE programs pursuant to G.S. 62-133.9(f) were not included in the class-allocation factor calculations. Based upon his review, witness Floyd concluded that PEC's allocations in the present proceeding are consistent with previous DSM/EE cost recovery proceedings and prior Commission orders.

The Commission notes that no party opposed PEC's proposed recovery of net lost revenues and program incentives. The Commission finds that such proposed recovery is consistent with the Commission's Sub 931 Order, as modified by the Commission's November 25, 2009 Order Granting Motions for Reconsideration in Part, issued in that same docket, and that net lost revenues and program incentives are appropriate for recovery in this proceeding, subject to further review in PEC's future annual DSM/EE rider proceedings, to the extent allowed in the Commission-modified Stipulation and Mechanism. The Commission concludes that PEC has complied with G.S. 62-133.9, Commission Rule R8-69, and the Sub 931 Order, as modified by the Commission's November 25, 2009 Order Granting Motions for Reconsideration in Part, with regard to calculating costs and incentives for the test, prospective, and rate periods at issue in this proceeding.

Therefore, the Commission finds and concludes that for the purposes of determining the DSM/EE EMF rider to be set in this proceeding, PEC's reasonable and prudent North Carolina retail total test period amount, consisting of its amortized DSM/EE O&M costs, capital costs, taxes, amortized incremental A&G costs, carrying charges, net lost revenues, and program incentives is $31,416,882. The Commission further concludes that subject to review in PEC's next annual DSM/EE rider proceeding, PEC's North Carolina retail total DSM/EE program amount for the prospective period consisting of its amortized O&M costs, capital costs, taxes, amortized incremental A&G costs, carrying charges, and net lost revenues is $11,607,966. The sum of these two amounts is $43,024,848 and it should be reduced by $6,047,851 to remove the revenue requirement for the period April 1, 2010 to July 31, 2010, to avoid double counting amounts already recognized in Docket No. E-2, Sub 977. Therefore, the Commission finds that $36,976,997 is appropriate to use to develop the DSM/EE EMF revenue requirement. For purposes of the DSM/EE rider to be set in this proceeding and subject to review in PEC's future DSM/EE rider proceedings, the Commission concludes that PEC's reasonable and appropriate estimate of its North Carolina retail DSM/EE program rate period amounts, consisting of its amortized O&M costs, capital costs, taxes, amortized incremental A&G costs, carrying charges, net lost revenues, and program incentives is $65,354,771, and this is the appropriate amount to use to develop the DSM/EE revenue requirement.

Based upon the testimony of witness Evans, the affidavits of witnesses Maness and Floyd, and the entire record in this proceeding, the Commission finds and concludes that the DSM/EE EMF riders proposed by PEC in the August 23, 2011 supplemental direct testimony of PEC witness Evans for the Residential, General Service, and Lighting rate classes are appropriate. The Commission further concludes that the forward-looking DSM/EE riders proposed by PEC in the August 23, 2011 supplemental direct testimony of PEC witness Evans to be charged during the rate period for the Residential, General Service, and Lighting rate schedules are appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence for this finding of fact can be found in the affidavit of Public Staff witness Floyd.

Public Staff witness Floyd recommended that future EM&V analyses should incorporate more detail, as appropriate for the measure being analyzed, especially regarding: net-to-gross savings; using PEC service-area-specific climate data, where available; the establishment of more accurate baselines, where realistically and cost effectively achievable; and the inclusion of a larger sample size for the duct sealing and attic insulation measures in the RHEIP analysis. No party indicated that it disagreed with the Public Staff's recommendations. Public Staff witness Floyd also recommended that PEC should be required to file a more detailed EM&V schedule.

The Commission agrees with the Public Staff that PEC should incorporate more detail, as described by witness Floyd, in its future EM&V analyses. The Commission finds and concludes that PEC should file its EM&V schedule, including identification of major milestones such as the schedule for completing the initial sample design; the schedule for completing the process and impact evaluations; and the date for the completion of the EM&V report for each DSM/EE program. The Commission requests that PEC and the Public Staff collaborate on the definition of major milestones that should be included in the EM&V schedule. Further, the Commission finds and concludes that the parties should file an EM&V schedule with the Commission, which incorporates such additional details, within 60 days of the date of this Order.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

The evidence for this finding of fact can be found in the affidavits of Public Staff witnesses Maness and Floyd.

Public Staff witness Maness stated that, in this proceeding, PEC had adjusted its proposed PPI incentives to reflect the results of a recently completed EM&V analysis of its RHEIP for the 2009 Vintage Year, and that Public Staff witness Floyd addressed this analysis in his affidavit. (The Commission's findings with regard to Public Staff witness Floyd's review will not be repeated as they have been previously set forth in the Evidence and Conclusions for Finding of Fact No. 13.) Witness Maness explained that based upon the results of that analysis, PEC had recalculated the PPI due on the RHEIP for Vintage Year 2009 and as recalculated, the annual levelized PPI amount related to RHEIP measures installed/implemented during the Vintage Year 2009 was reduced from $52,551 to $10,405. Witness Maness stated that PEC is proposing to true up the PPI previously approved in the Sub 977 Proceeding for Vintage Year 2009 RHEIP measures to reflect the results of its recently completed EM&V analysis.

With respect to PEC's EM&V based true-up adjustment, witness Maness stated that based on his review, the adjustment to the PPI amount had been made in a reasonable manner and that the analogous adjustments to the net lost revenue calculations also appear to have been pursued in a reasonable manner. Witness Maness also noted that all of the net lost revenues and PPI incentive amounts included in the riders approved in this proceeding (with the exception of those trued up in this proceeding related to the 2009 Vintage Year RHEIP), including those within the DSM/EE EMF riders, remain subject to true-up in future proceedings.

The Commission finds and concludes that PEC's requested true-up of its RHEIP for Vintage Year 2009 activities is in compliance with the governing provisions contained in the Commission's Sub 931 Order and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

This finding of fact is supported in part by Paragraph No. 2.D. of the Stipulation, and Paragraph No. 45 of the Mechanism, which states that the Mechanism will be revisited by the stipulating parties every three years, and the Commission's general statutory authority over PEC's rates. Therefore, the Commission finds and concludes that the Public Staff should initiate a formal review of the Commission-approved Mechanism not later than June 1, 2012, unless requested to do so earlier by PEC or another interested party. Such review should specifically address whether the incentives in the Commission-approved Mechanism are producing significant DSM and EE results; whether the customer rate impacts from the DSM/EE rider are reasonable and appropriate; whether overall portfolio performance targets should be adopted; and any other relevant issues that may arise during the review process.

IT IS, THEREFORE ORDERED, as follows:

1. That the appropriate DSM/EE EMF riders, *excluding* gross receipts tax and the North Carolina regulatory fee, for the Residential and General Service rate classes are increments of 0.006 cents per kWh and 0.001 cents per kWh, respectively, and a decrement of 0.009 cents per kWh for the Lighting rate class. *Including* gross receipts tax and the North Carolina regulatory fee, these DSM/EE EMF riders are increments of 0.006 cents per kWh and 0.001 cents per kWh, respectively, for the Residential and General Service rate classes, and a decrement of 0.009 cents per kWh for the Lighting rate class.

2. That the appropriate DSM/EE riders to be charged by PEC during the rate period for the Residential, General Service, and Lighting rate classes are increments of 0.290 cents per kWh, 0.185 cents per kWh, and 0.094 cents per kWh, respectively, *excluding* gross receipts tax and the North Carolina regulatory fee. *Including* gross receipts tax and the North Carolina

regulatory fee, the rates for the Residential, General Service, and Lighting rate classes are increments of 0.300 cents per kWh, 0.191 cents per kWh, and 0.097 cents per kWh, respectively.

3. That the appropriate total DSM/EE annual riders including PEC's proposed EMF riders for the Residential, General Service, and Lighting rate classes are increments of 0.296 cents per kWh, 0.186 cents per kWh, and 0.085 cents per kWh, respectively, *excluding* gross receipts tax and the North Carolina regulatory fee. *Including* gross receipts tax and the North Carolina regulatory fee, the total riders for the Residential, General Service, and Lighting rate classes are increments of 0.306 cents per kWh, 0.192 cents per kWh, and 0.088 cents per kWh, respectively.

4. That within five days of the date of this Order, PEC shall file appropriate rate schedules and riders with the Commission in order to implement these adjustments. Such rates are to become effective for service rendered on or after December 1, 2011.

5. That PEC shall work with the Public Staff to prepare a joint proposed Notice to Customers giving notice of the rate changes ordered by the Commission in Docket No. E-2, Subs 1000, 1001, and 1002, and PEC shall file such proposed notice for Commission approval as soon as practicable.

6. That PEC shall continue to provide a list of GEA initiatives and the volume of activity associated with each initiative during the test period in future DSM/EE rider proceedings; and that PEC and the Public Staff shall jointly investigate the feasibility and cost of conducting a market survey to assess the effectiveness of PEC's GEA activities as soon as practicable.

7. That PEC shall consult with the Public Staff and agree upon enhancements to be implemented to incorporate more detail into its EM&V reports.

8. That PEC and the Public Staff shall agree upon the major milestones to be incorporated into PEC's EM&V schedule, and that PEC shall within 60 days of the date of this Order file an EM&V schedule which incorporates the agreed-upon additional details.

9. That not later than June 1, 2012, unless requested to do so earlier by PEC or another interested party, the Public Staff shall initiate a formal review of the Commission-approved Mechanism. Such review shall specifically address whether the incentives in the Commission-approved Mechanism are producing significant DSM and EE results; whether the customer rate impacts from the DSM/EE rider are reasonable and appropriate; whether overall portfolio performance targets should be adopted; and any other relevant issues that may be identified during the review process.

ISSUED BY ORDER OF THE COMMISSION
This the 14th day of November, 2011.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

fh111411.01

DOCKET NO. E-22, SUB 475

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Virginia Electric and Power Company, d/b/a Dominion North Carolina Power, for Approval of 2010 Renewable Energy and Energy Efficiency Portfolio Standard Compliance Report Pursuant to Commission Rule R8-67	)))))	ORDER APPROVING 2010 REPS COMPLIANCE

HEARD: Wednesday, November 9, 2011, beginning at 10:43 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 Lorinzo L. Joyner, William T. Culpepper, III, Susan W. Rabon, ToNola D. Brown-Bland, and Lucy T. Allen

APPEARANCES:

For Dominion North Carolina Power:

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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

BY THE COMMISSION: On August 25, 2011, Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (Dominion North Carolina Power, DNCP, or the Company), filed its 2010 Renewable Energy and Energy Efficiency Portfolio Standard (REPS) compliance report, along with the supporting testimony and exhibits of Chiman H. Muchhala, Manager-Market Operations, and Kurt W. Swanson, Manager-Regulatory & Pricing, pursuant to G.S. 62-133.8 and Commission Rule R8-67(c).

On September 8, 2011, the Commission issued an Order Scheduling Hearing, Establishing Testimony and Discovery Guidelines, and Requiring Public Notice, in which it set this matter for hearing; established deadlines for the submission of intervention petitions, intervenor testimony, and DNCP's rebuttal testimony; required the provision of appropriate public notice; and mandated compliance with certain discovery guidelines.

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

On October 18, 2011, the Public Staff filed the direct testimony of Jay B. Lucas, Electric Engineer.

On October 24, 2011, DNCP requested that the Commission excuse its witnesses in this proceeding, Chiman H. Muchhala and Kurt W. Swanson, from attending the evidentiary hearing scheduled for November 9, 2011, noting that the Public Staff's testimony recommended that the Commission approve DNCP's 2010 REPS compliance report, and that DNCP did not request a REPS cost recovery rider. On October 27, 2011, the Commission issued an Order Granting Request to Excuse Witnesses granting DNCP's request.

On October 31, 2011, the Public Staff requested that the Commission excuse its witness Jay B. Lucas from attending the evidentiary hearing scheduled for November 9, 2011. The Commission granted this request by Order Granting Request to Excuse Public Staff Witness issued November 2, 2011.

On November 2, 2011, DNCP filed a letter notifying the Commission that the Company would not submit rebuttal testimony in the proceeding, as the Company concurred with the recommendation of the Public Staff that the Commission approve DNCP's 2010 REPS compliance report (DNCP Letter).

Also on November 2, 2011, DNCP filed the affidavit of publication showing the Company's publication of notice of the November 9, 2011, hearing as required by the September 8, 2011, Scheduling Order.

The case came on for hearing as scheduled on November 9, 2011. No public witnesses appeared at the hearing.

For the Company, the following were received into evidence: DNCP's 2010 REPS compliance report, the direct testimony for Chiman H. Muchhala and Kurt W. Swanson, and the DNCP Letter filed November 2, 2011. The Commission also received into evidence the direct testimony of Jay B. Lucas. All exhibits attached to the witnesses' testimony were received into evidence.

Based upon the foregoing, the testimony and exhibits introduced at the hearing, DNCP's records in the North Carolina Renewable Energy Tracking System (NC-RETS), and the entire record in this proceeding, the Commission makes the following:

FINDINGS OF FACT

1. DNCP 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 North Carolina. DNCP is lawfully before this Commission based on its application filed pursuant to G.S. 62-133.8 and Commission Rule R8-67.

2. Beginning in 2010, under the REPS established by G.S. 62-133.8, electric power suppliers must supply at least 0.02% of their previous year's North Carolina retail energy sales by a combination of new solar electric facilities and new metered solar thermal energy facilities. In 2012, this solar requirement increases to 0.07% of the previous year's North Carolina retail sales. Also in 2012, electric power suppliers must generally meet 3% of their previous year's North Carolina retail electric sales by a combination of renewable energy and energy reductions. Beginning in 2012, electric power suppliers are required by G.S. 62-133.8(e) and (f) to procure a certain portion of their renewable energy requirements from electricity generated from poultry and swine waste.

3. DNCP has not requested cost recovery or submitted an annual rider pursuant to G.S. 62-133.8(h)(4) and Commission Rule R8-67(e).

4. DNCP has agreed to provide REPS compliance services for the Town of Windsor, an electric power supplier that is a wholesale customer of the Company.

5. DNCP's use of out-of-state solar RECs to meet 100% of its REPS obligation is appropriate.

6. DNCP's use of out-of-state solar RECs to meet 25% of the REPS obligation for the Town of Windsor is appropriate.

7. DNCP and the Town of Windsor met their 2010 REPS obligations and DNCP's 2010 REPS compliance report should be approved. DNCP should clarify Windsor's 2009 retail sales in a compliance filing.

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

These findings of fact are essentially informational, jurisdictional, and procedural in nature and are not contested.

G.S. 62-133.8 establishes a REPS for all electric power suppliers in North Carolina. The statute requires, for example, each electric public utility to provide a certain percentage of its North Carolina retail sales from various renewable energy or energy efficiency resources, including the following: (a) generating electric power at a new renewable energy facility; (b) using 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) reducing energy consumption through the implementation of energy efficiency

(EE) measures; (d) purchasing electric power from a new renewable energy facility; (e) purchasing renewable energy certificates (RECs); (f) using electric power that is supplied by a new renewable energy facility or saved due to the implementation of an EE measure that exceeds the requirements of the REPS for any calendar year as a credit towards the requirements of the REPS in the following calendar year; or (g) electricity demand reduction. Each of these measures is subject to certain additional limitations and conditions. In 2012, DNCP must generally meet 3% of its previous year's North Carolina retail electric sales by a combination of these measures.

G.S. 62-133.8(d) requires a certain percentage of the total electric power sold to retail electric customers of 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 0.02% in 2010 and 2011, and 0.07% in 2012.

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. In 2012, the aggregate requirement for swine waste resources is 0.07%. 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 is 170,000 megawatt-hours. 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, DNCP's share of the aggregate State set-aside requirements for energy from swine and poultry waste is based on the ratio of its North Carolina retail megawatt-hour sales for the previous year divided by the previous year's total North Carolina retail megawatt-hour sales.

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. The Company stated in its 2010 REPS compliance report that it is not seeking recovery of its REPS compliance costs at this time. The Company recognizes that any recovery of these costs will need to be approved by the Commission.

DNCP's 2010 REPS compliance report also stated that the Company is responsible for meeting the REPS requirements for the Town of Windsor, a wholesale customer of DNCP.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence for this finding of fact is found in DNCP's 2010 REPS compliance report, the testimony of Public Staff witness Lucas, and the Commission's September 22, 2009 Order in Docket No. E-100, Sub 113.

The Commission's September 22, 2009, Order on Dominion's Motion for Further Clarification, issued in Docket No. E-100, Sub 113, clarified that G.S. 62-133.8(b)(2)e expressly exempts DNCP from the 25% limitation on the use of unbundled out-of-state RECs. Pursuant to this clarification, DNCP's 2010 REPS compliance report stated that it met 100% of its solar set-aside REPS obligations by purchasing out-of-state solar RECs.

Public Staff witness Lucas testified that the solar RECs used by DNCP to meet its REPS obligations are valid for use, and that the Public Staff identified no problems with the records pertaining to the RECs used for DNCP's obligations.

Based on the foregoing evidence, the Commission concludes that DNCP's use of out-of-state solar RECs to meet 100% of its own REPS obligation is appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence for this finding of fact is found in DNCP's 2010 REPS compliance report, the testimony of DNCP witness Muchhala, and the testimony of Public Staff witness Lucas.

Pursuant to the Commission's September 22, 2009 Order, Windsor is permitted to meet up to 25% of its solar set-aside requirements with unbundled out-of-state RECs. In addition, DNCP's 2010 REPS compliance report stated that, based on guidance and advice received from the Public Staff, the Company met Windsor's solar set-aside requirements with two out-of-state solar RECs and eight in-state solar RECs. DNCP's compliance report stated that it intends to meet Windsor's solar set-aside requirements going forward by purchasing RECs to meet 75% of Windsor's solar set-aside REPS requirements from solar facilities located inside the State.

Public Staff witness Lucas testified that the solar RECs used by DNCP to meet Windsor's REPS obligations are valid for use, and that the Public Staff identified no problems with the records pertaining to the RECs used for Windsor's REPS obligations.

Based on the foregoing evidence, the Commission finds and concludes that DNCP appropriately used out-of-state solar RECs to meet 25% of Windsor's solar set-aside REPS obligation and in-state solar RECs to meet 75% of Windsor's obligation.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence supporting this finding of fact appears in DNCP's 2010 REPS compliance report, the testimony and exhibits of DNCP witnesses Muchhala and Swanson, the testimony of Public Staff witness Lucas, and the records contained in the North Carolina Renewable Energy Tracking System (NC-RETS).

Witness Muchhala testified that the Company's actual 2009 retail sales in North Carolina were 4,028,436 megawatt-hours (MWh), making its 2010 REPS obligation 806 solar RECs. Witness Muchhala testified that Windsor's actual 2009 retail sales were 47,467 MWh, making its 2010 REPS obligation 10 solar RECs. No party disagreed with witness Muchhala regarding Windsor's REPS obligation. However, the Commission notes that the 2009 retail sales recorded for Windsor in its NC-RETS 2010 compliance sub-account is a slightly different amount: 47,492 MWh. The difference is immaterial because in either case, Windsor's obligation for 2010 remains 10 solar RECs.

Witness Muchhala stated that DNCP satisfied its own and Windsor's REPS obligations for 2010 through the purchase of 806 and 10 qualifying solar RECs, respectively. Witness

Muchhala explained that its strategy on compliance with the solar set-aside for 2011 and beyond is to continue to buy unbundled out-of-state RECs, and, on behalf of Windsor, to purchase 75% of its required solar RECs from solar facilities located inside the State.

Witness Muchhala stated that DNCP has already purchased or entered into contracts to purchase solar RECs to meet its compliance obligations for 2011 through 2014 and approximately 35% of its obligations for 2015-2017. The solar RECs purchased through these agreements can also be used to meet the 25% of Windsor's obligations that are permitted to be satisfied from out-of-state sources.

Finally, witness Muchhala stated that the Company has entered into agreements with other electric suppliers to conduct joint requests for proposals (RFPs) for purposes of compliance with the poultry and swine waste set-asides starting in 2012, and based on common RFPs issued by this group, the Company has signed long-term contracts with five swine waste REC suppliers. The joint buyers group is negotiating with a poultry waste generation REC supplier for a long term contract, and DNCP is looking for poultry REC suppliers out of state. Witness Muchhala testified that DNCP intends to comply with the general REPS requirements beginning in 2012 on behalf of itself and Windsor through obtaining RECs as permitted under North Carolina law, using approved EE programs and new Company-generated renewable energy where economically feasible.

DNCP witness Muchhala provided confidential testimony detailing the costs expended by the Company in satisfying its REPS obligations. He stated that, to date, the Company had not imposed any per-account annual charges on customers, due to the relatively small cost of compliance so far.

DNCP witness Swanson testified that the Company had decided not to seek to recover its REPS compliance costs this year. He stated that prior to filing an application to implement a REPS rider in the future, DNCP will inform the Public Staff regarding the manner in which DNCP will determine its customer count for purposes of the annual cost cap and for billing of any REPS rider.

Public Staff witness Lucas testified that he reviewed DNCP's 2010 REPS compliance report and found that it meets the requirements of Commission Rule R8-67(c) for both DNCP and Windsor. He stated that DNCP had created separate accounts in NC-RETS for itself and Windsor as required by Commission Rule R8-67(h)(3). Witness Lucas testified further that the 806 out-of-state solar RECs placed by DNCP in its NC-RETS 2010 compliance sub-account meet the REPS requirement that 0.02% of 2009 retail sales in MWh be matched with an equivalent number of RECs derived from solar energy resources in 2010, and that the eight solar RECs from in-state and two solar RECs from out-of-state placed by DNCP in the compliance sub-account for Windsor also meet this requirement. He stated that the Public Staff believes that all of these RECs are valid for use in meeting the 2010 REPS requirements. Finally, witness Lucas recommended that the Commission approve DNCP's 2010 REPS compliance report filed on behalf of the Company and Windsor.

No other evidence was presented on DNCP's 2010 REPS compliance report. Therefore, the Commission finds and concludes that DNCP and the Town of Windsor have fully complied with the requirements of the REPS for 2010, and that DNCP's 2010 REPS compliance report should be approved. However, the Commission will require DNCP to file a verified submittal attesting to Windsor's 2009 retail sales and informing the Commission that it has, if necessary, corrected the data in NC-RETS to conform with that submittal.

IT IS, THEREFORE, ORDERED as follows:

1. That DNCP's 2010 REPS compliance report is approved; and

2. That DNCP shall, by January 13, 2012, file a verified attestation as to Windsor's 2009 retail sales and the status of that data in NC-RETS.

ISSUED BY ORDER OF THE COMMISSION.
This the 15th day of December 2011.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

kh121311.01

DOCKET NO. EC-33, SUB 58

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Halifax Electric Membership Corporation – 2008 REPS Compliance Report	) ORDER ON 2008 REPS) COMPLIANCE REPORT

HEARD: Wednesday, August 11, 2010, 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, Susan W. Rabon, ToNola D. Brown-Bland, and Lucy T. Allen

APPEARANCES:

For Halifax Electric Membership Corporation:

H. Lawrence Armstrong, Jr., Armstrong Law, PLLC, Post Office Box 187, Enfield, North Carolina 27823

For GreenCo Solutions, Inc.:

Richard M. Feathers, Associate General Counsel, GreenCo Solutions, Inc., Post Office Box 27306, Raleigh, North Carolina 27611-7306

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

BY THE COMMISSION: In August 2007, North Carolina enacted comprehensive energy legislation, Session Law 2007-397 (Senate Bill 3), which, among other things, established a Renewable Energy and Energy Efficiency Portfolio Standard (REPS), the first renewable energy portfolio standard in the Southeast. Under the REPS, beginning in 2010 all electric power suppliers in North Carolina must meet an increasing amount of their retail customers' energy needs by a combination of renewable energy resources (such as solar, wind, hydropower, geothermal and biomass) and reduced energy consumption.

On February 29, 2008, and March 13, 2008, the Commission issued Orders in Docket No. E-100, Sub 113 adopting rules to implement Senate Bill 3 and the REPS in North Carolina. Commission Rule R8-67(c)(1) provides as follows:[1]

[1] Commission Rule R8-67(c) was recently amended by Order dated January 31, 2011, in Docket No. E-100, Sub 113. The references to Rule R8-67(c) in this Order are to the Rule in effect at the time the 2008 REPS compliance report was filed.

> Each year, beginning in 2009, each electric power supplier shall file with the Commission a report describing the electric power supplier's compliance with the requirements of G.S. 62-133.8(b), (c), (d), (e) and (f) during the previous calendar year.

Pursuant to Rule R8-67(c)(3), each electric membership corporation (EMC) and municipal electric supplier is required to file its REPS compliance report with the Commission on or before September 1 of each year. Rule R8-67(c)(3) further provides:

> The Commission shall issue an order scheduling a hearing to consider the REPS compliance report filed by each electric membership corporation or municipal electric supplier, requiring public notice, and establishing deadlines for intervention and the filing of additional direct and rebuttal testimony and exhibits.

Commission Rule R8-67(c)(1) sets out the information that the REPS compliance report should include. First, the electric power supplier must list the sources, amounts, and costs of renewable energy certificates (RECs) it used to comply with the REPS. For RECs derived from energy efficiency (EE), the Rule permits electric power suppliers to use estimates of reduced energy consumption through the implementation of EE measures, to the extent approved by the Commission. The REPS compliance report must also include the electric power supplier's actual North Carolina retail sales and number of customer accounts by customer class at year-end. Additionally, the report should state the electric power supplier's current avoided cost rates, as well as the avoided cost rates applicable to energy received pursuant to long-term power purchase agreements. Next, the report should include the actual total and incremental costs incurred to comply with the REPS, as well as a comparison of actual compliance costs to the annual cost caps. The REPS compliance report should discuss the status of the electric power supplier's compliance with the REPS. The report should also identify any RECs to be carried forward. For each renewable energy facility providing RECs used to comply with the REPS, the report should contain the name, address, and owner of the renewable energy facility and an affidavit from the owner of the renewable energy facility certifying that the energy associated with the RECs was derived from a renewable energy resource, identifying the technology used, and listing information regarding payments received and meter readings. For EMCs and municipal electric suppliers, the report should also state the reduced energy consumption achieved after January 1, 2008, through the implementation of demand-side management (DSM) programs.

On September 1, 2009, pursuant to Commission Rule R8-67(c)(1), Halifax EMC (Halifax), filed its REPS compliance report for calendar year 2008 in Docket No. E-100, Sub 124 on behalf of itself and the Town of Enfield.

On May 11, 2010, the Commission established this docket and issued an Order scheduling a hearing on Halifax's 2008 REPS compliance report, establishing discovery guidelines and deadlines for filing testimony, and requiring public notice. The Commission ordered Halifax to file a copy of its 2008 REPS compliance report in this docket as an exhibit to the testimony of Halifax's sponsoring witness. The Commission further requested the Public Staff to participate in this proceeding.

On June 2, 2010, Halifax filed the direct testimony and exhibits of Charles H. Guerry, Executive Vice President of Halifax.

Petitions to intervene were filed by GreenCo Solutions, Inc., on June 10, 2010; by the North Carolina Sustainable Energy Association on June 25, 2010; and by North Carolina Municipal Power Agency 1, North Carolina Eastern Municipal Power Agency, and ElectriCities, Inc., on July 15, 2010. The petitions to intervene were allowed by the Commission on June 17, 2010, July 1, 2010, and July 20, 2010, respectively. The intervention of the Public Staff is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

On July 26, 2010, the Public Staff filed the testimony and exhibits of Jay B. Lucas, Electric Engineer, and on August 2, 2010, Halifax filed the rebuttal testimony and exhibits of witness Guerry.

The hearing was held as scheduled on August 11, 2010. The parties stipulated to the admission without cross-examination of the testimony and exhibits of witnesses Guerry and Lucas.

Based upon the foregoing, the testimony and exhibits introduced into evidence at the hearing, and the Commission's record of this proceeding, the Commission now makes the following

FINDINGS OF FACT

1. Halifax is an EMC organized pursuant to the Electric Membership Corporation Act codified in Chapter 117 of the North Carolina General Statutes for the purpose of, inter alia, serving communities not served, or inadequately served, with electrical energy.

2. Halifax provides retail electric service to customer-owners of Halifax and retail customers of the Town of Enfield.

3. Halifax is an all-requirements customer of the North Carolina Electric Membership Corporation (NCEMC).

4. The combined 2008 retail sales for Halifax and the Town of Enfield were 194,623,652 kilowatt-hours (kWh), with 11,689 residential accounts, 1,455 commercial accounts, and one industrial account.

5. The appropriate aggregate incremental cost cap for Halifax for 2008 is $191,050.

6. During 2008, Halifax operated three EE programs: compact fluorescent lighting (CFL) installations, Residential Energy Audit implementation initiatives, and Energy Star heat pump installations. The RECs estimated for these programs were 14.1, 203.9, and 11.3, respectively.

7. Halifax's quantification of its potential EE RECs should be accepted in this proceeding, subject to resolution of the issues posed in the August 24, 2010 Order in regard to measurement and verification (M&V) of reduced energy consumption in Docket No. E-100,

Sub 113, and reconsideration following the submission of Halifax's M&V data supporting such estimates.

8. Halifax's revised 2008 REPS compliance report should reflect the 51.6 RECs from the Story Wind Project it was allocated by NCEMC at an incremental cost of $42.31, or $0.82/REC.

9. In reporting purchases from the Southeastern Power Administration (SEPA), Halifax may include the total amount of SEPA energy purchased by Halifax and the Town of Enfield.

10. Costs incurred by Halifax for implementing existing DSM and EE programs may not be included as REPS compliance costs.

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

The evidence supporting these findings of fact appears in Chapter 117 of the North Carolina General Statutes, of which the Commission takes judicial notice, and in the testimony of Halifax witness Guerry. These findings are informational, jurisdictional, and procedural in nature.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4 - 5

The evidence supporting these findings of fact appears in the testimony and exhibits of Halifax witness Guerry and Public Staff witness Lucas.

Halifax witness Guerry testified that the combined 2008 retail sales for Halifax and the Town of Enfield were 194,623,652 kWh; with 11,689 residential accounts, 1,455 commercial accounts, and one industrial account. Halifax calculated its incremental cost cap by multiplying the reported year-end aggregate number of accounts for each customer class by the per-account annual charges set out in G.S. 62-133.8(h)(4): $10.00 for residential customers, $50.00 for commercial customers, and $500.00 for industrial customers. G.S. 62-133.8(h)(3) provides that electric power suppliers shall be deemed to be in compliance with the REPS requirements if the incremental costs incurred to meet the requirements reach the per-account incremental cost cap. The appropriate aggregate incremental cost cap for Halifax for 2008 is $191,050.

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

The evidence supporting these findings of fact appears in the testimony and exhibits of Halifax witness Guerry and Public Staff witness Lucas.

According to Halifax witness Guerry, during 2008, Halifax operated three EE programs: CFL installations, Residential Energy Audit implementation initiatives, and Energy Star heat pump installations. The RECs estimated by Halifax for these programs were 14.1, 203.9, and 11.3, respectively. Exhibit HEMC-2 and Lucas Exhibit 2 provide M&V information provided by Halifax to estimate these RECs.

Public Staff witness Lucas testified that he had not been able to determine whether Halifax's EE programs are cost-effective or whether the RECs claimed are verifiable. He stated that, while the M&V information provided for these programs was insufficient to verify the energy savings, the Public Staff could accept Halifax's quantification of its potential EE RECs in this proceeding.

Commission Rule R8-67(c)(1)(i) allows EMCs to base their quantification of EE RECs on estimates of reduced energy consumption through the implementation of EE measures, to the extent approved by the Commission. The Commission notes that in its August 24, 2010 Order Requesting Comments on Measurement and Verification of Reduced Energy Consumption in Docket No. E-100, Sub 113, the Commission requested comments and reply comments regarding the appropriate M&V documentation to be submitted in reference to EE/DSM programs and the proceeding, if any, in which such documentation should be reviewed. The Commission agrees with Mr. Lucas that Halifax's quantification of its potential EE RECs should be accepted in this proceeding, subject to resolution of the issues posed in the August 24, 2010 Order in regard to M&V of reduced energy consumption in Docket No. E-100, Sub 113, and reconsideration following the submission of further M&V data supporting such estimates.

Halifax witness Guerry testified that two of Halifax's EE programs, the Residential Energy Audit implementation initiative and Energy Star heat pump installations, predate the enactment of Senate Bill 3. He also noted that Halifax filed for approval of the CFL installation program on March 26, 2010 in Docket No. EC-33, Sub 57. That program was approved by the Commission on December 14, 2010.

Public Staff witness Lucas noted that, in its February 8, 2010 comments in Docket No. E-100, Subs 118 and 124, the Public Staff recommended that Halifax apply for approval of any EE programs which "offer incentives to customers and were adopted and implemented after August 20, 2007." Mr. Guerry pointed out that Halifax filed a letter in Docket No. E-100, Subs 118 and 124 on March 25, 2010, in which it indicated that, unless the Commission directed otherwise, Halifax did not intend to file anything further regarding its existing EE programs. Mr. Lucas noted that a proper filing for approval under Commission Rule R8-68 requires information regarding the cost-effectiveness of the proposed EE program or measure. He recommended that Halifax apply for approval of its residential energy audit and the Energy Star heat pump programs.

G.S. 62-133.9(c), enacted August 20, 2007, by Senate Bill 3, provides, "Each electric power supplier to which G.S. 62-110.1 applies ... shall submit cost-effective demand-side management and energy efficiency options that require incentives to the Commission for approval." Consistent with this provision, on August 10, 2010, the Commission issued its Order Approving Integrated Resource Plans and REPS Compliance Plans in Docket No. E-100, Subs 118 and 124, in which it ordered, in part, that "any EMC which seeks to implement, or is currently implementing DSM or EE programs under which incentives are offered to customers ... file such programs for Commission approval under G.S. 62-133.9(c) and Commission Rule R8-68 if they were adopted and implemented after August 20, 2007." Halifax is subject to G.S. 62-110.1, and its Residential Energy Audits and Heat Pump Rebates programs provide customer incentives; however, each program was established prior to August 20, 2007.

Thus, neither program is required to be submitted to the Commission for approval pursuant to G.S. 62-133.9(c) and the Commission's IRP order.

G.S. 62-140(c), however, provides as follows:

> No public utility [including, effective 1965, any EMC operating within this State] shall offer or pay any compensation or consideration or furnish any equipment to secure the installation or adoption of the use of such utility service except upon filing of a schedule of such compensation or consideration or equipment to be furnished and approved thereof by the Commission....

Again, both the Residential Energy Audits and Heat Pump Rebates programs provide compensation to Halifax's customers. The issue under G.S. 62-140(c) and Commission Rule R8-68 then becomes whether the compensation is paid "to secure the installation or adoption of the use of such utility service," i.e., to increase electric utility service. Lucas Exhibit 2, attached to his testimony, provides brief details about the two EE programs. It appears that the Residential Energy Audits program is not intended to provide compensation to customers in order to secure the installation or adoption of the use of such utility service because the customer only receives a credit based on demonstrated energy reductions after making improvements identified in the audit. Under the Heat Pump Rebates program, however, participants are provided an incentive if they install a high efficiency heat pump. In this case, it is not clear whether the customer is converting from lower efficiency electric heating or switching from propane or natural gas. The Commission, therefore, concludes that Halifax should file its Heat Pump Rebates program for approval pursuant to G.S. 62-140(c) and Commission Rule R8-68.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence supporting this finding of fact appears in the testimony and exhibits of Halifax witness Guerry and the testimony Public Staff witness Lucas.

Halifax witness Guerry testified that Halifax's 2008 REPS compliance report does not reflect 51.6 RECs from the Story Wind Project allocated to it by NCEMC at an assigned cost of $42.31, or $0.82/REC. Halifax agreed to refile its 2008 REPS compliance report to reflect the RECs associated with this project. The Commission takes judicial notice that Halifax filed its 2009 REPS compliance report on October 15, 2010, in this docket and in Docket No. E-100, Sub 128, in which it revised its 2008 REPS compliance report to include the Story Wind Project RECs and the associated costs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The evidence supporting this finding of fact appears in the testimony and exhibits of Halifax witness Guerry and the testimony and exhibits of Public Staff witness Lucas. In addition, the Commission takes judicial notice of its Order Approving REPS and REPS EMF Riders, issued August 13, 2010, in Docket No. E-7, Sub 936.

Public Staff witness Lucas testified that Halifax's 2008 REPS compliance report did not list any RECs acquired through purchases from SEPA. He noted that Halifax had indicated in response to a data request that it had acquired RECs from SEPA during 2008. Mr. Lucas recommended that Halifax refile its 2008 REPS compliance report and include RECs acquired through its 2008 SEPA purchases so that the RECs could be banked and counted toward future years' REPS compliance.

Public Staff witness Lucas testified that SEPA is an agency of the federal government that markets hydroelectric power generated at reservoirs in the southeastern United States operated by the Army Corps of Engineers. He stated that SEPA gives preference to municipalities and cooperatives, many of which in North Carolina buy SEPA power. Mr. Lucas explained that there are three sources of energy that SEPA provides to the municipalities and cooperatives: stream flow energy from traditional hydroelectric generation; pumping operations energy from water released by a pumped storage system; and replacement energy purchased by SEPA to meet its capacity obligations to its customers when its own hydroelectric generation is insufficient. Mr. Lucas presented as an exhibit a sample SEPA bill showing energy provided from these three sources. Witness Lucas noted that G.S. 62-133.8(c)(2)(c) allows a cooperative or a municipality to meet part of its REPS requirements by "[p]urchas[ing] electric power from a renewable energy facility or hydroelectric power facility, provided that no more than thirty percent (30%) of the requirements of this section may be met with hydroelectric power, including allocations made by the Southeastern Power Administration." Mr. Lucas recommended that any RECs reported in connection with the SEPA power by Halifax in its 2008 REPS compliance report should only include stream flow energy from SEPA. Halifax witness Guerry agreed that Halifax should include RECs from its SEPA allocation, but disagreed with Mr. Lucas that such RECs only reflect those including stream flow energy. Mr. Lucas indicated that such RECs had no incremental cost to Halifax in 2008.

In Docket No. E-7, Sub 936, the Commission reviewed this issue with respect to SEPA allocation credits given by Duke Energy Carolinas, LLC, to wholesale entities for which it provides compliance services. In its August 13, 2010 Order in that docket, the Commission interpreted Senate Bill 3 and concluded that the total amount of energy purchased by a municipality or EMC pursuant to its "allocation from the Southeastern Power Administration" is eligible to be used for compliance with the purchasing municipality's or EMC's REPS requirements, subject to the thirty percent limitation provided in G.S. 62 133.8(c)(2)(c). "The term 'allocation' is a term of art in this context and the General Assembly is presumed to have used it as such in the statute." The Commission concludes that the same analysis and conclusion should be applied in this case. The Commission, therefore, finds and concludes that, in reporting purchases from SEPA, Halifax may include the total amount of energy purchased by Halifax and the Town of Enfield from SEPA.

Counsel for Halifax and the Public Staff indicated at the hearing that they had agreed that SEPA RECs would be reflected in Halifax's 2009 REPS compliance report. The Commission takes judicial notice that Halifax filed its 2009 REPS compliance report on October 15, 2010, in this docket and in Docket No. E-100, Sub 128, in which it revised its 2008 REPS compliance report to include its SEPA allocations.

Public Staff witness Lucas further recommended that Halifax be directed to provide the total cost and avoided cost of the SEPA energy purchased by its members. The Commission notes that Senate Bill 3 does not limit the amount of money that an electric power supplier spends on renewable energy or EE to meet its REPS obligation; it only limits the incremental costs associated with such expenditures. Although Rule R8-67(c)(1)(iv) requires Halifax to provide the actual total costs incurred for REPS compliance,[1] the costs incurred for SEPA power are unnecessary and irrelevant for determining Halifax's incremental costs or a comparison of Halifax's incremental costs with its per-account cost cap. Halifax did not enter into a long-term power purchase agreement for SEPA power to meet the requirements of Senate Bill 3, such as it might have done for a new solar photovoltaic or other renewable energy facility. Rather, it was simply allowed to count toward REPS compliance the SEPA power already being purchased pursuant to existing agreements. Thus, since Halifax is paying no more for SEPA power now that such power is able to be counted toward REPS compliance than it did previously, there is no incremental cost associated with SEPA RECs. In fact, SEPA does not earn RECs associated with the power it sells to Halifax; RECs associated with SEPA power are merely a convenience adopted by the Commission to be recorded by Halifax (similar to EE RECs) for ease in determining REPS compliance under Senate Bill 3. Similarly, with regard to avoided costs, Halifax already reports its avoided cost; there is no separate avoided cost associated with the energy it purchases from SEPA. The Commission, therefore, concludes that Halifax should not be required to include in its REPS compliance reports or in its calculation of REPS compliance costs the total cost and avoided cost of its SEPA power. To the extent that this is inconsistent with Rule R8-67(c)(1), the Commission believes that the peculiar circumstances related to these SEPA contracts were unanticipated by the Commission's rules and the requirement to file such information should be waived.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The evidence supporting this finding of fact appears in the testimony and exhibits of witness Guerry.

Halifax included in its 2008 REPS compliance report costs associated with the implementation of its Residential Energy Audits and Heat Pump Rebates programs, which were adopted prior to August 20, 2007.

G.S. 62-133.8(h)(3) provides that:

> the total annual incremental cost to be incurred by an electric power supplier and recovered from the electric power supplier's retail customers shall not exceed an

[1] Rule R8-67(c)(1), at the time Halifax filed its 2008 REPS compliance report, required each electric power supplier to provide, in part, the following information:

> (i) the sources, amounts, and costs of renewable energy certificates, by source, used to comply with G.S. 62 133.8(b), (c), (d), (e) and (f). Renewable energy certificates for energy efficiency may be based on estimates of reduced energy consumption through the implementation of energy efficiency measures, to the extent approved by the Commission;
>
> ...
>
> (iii) the current avoided cost rates and the avoided cost rates applicable to energy received pursuant to long-term power purchase agreements;
>
> (iv) the actual total and incremental costs incurred to comply with G.S. 62 133.8(b), (c), (d), (e) and (f);
>
> (v) a comparison of actual compliance costs to the annual cost caps;

> amount equal to the per-account annual charges set out in subdivision (4) of this subsection applied to the electric power supplier's total number of customer accounts determined as of December 31 of the previous calendar year.

In the absence of a federal renewable portfolio standard, the term "incremental costs" is defined in G.S. 62-133.8(h)(1) as follows:

> For the purposes of this subsection, the term "incremental costs" means all reasonable and prudent costs incurred by an electric power supplier to:
>
> a. Comply with the requirements of subsections (b), (c), (d), (e), and (f) of this section that are in excess of the electric power supplier's avoided costs other than those costs recovered pursuant to G.S. 62-133.9.
>
> b. Fund 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.

The issue before the Commission, then, is whether Halifax may include the costs of its existing EE programs as REPS compliance costs, a portion of which Halifax determined to be incremental costs subject to the incremental cost cap.

As noted previously, Halifax witness Guerry testified that two of Halifax's EE programs, the Residential Energy Audit implementation initiative and Energy Star heat pump installations, predate the enactment of Senate Bill 3. For the reasons set forth below, the Commission concludes that the implementation costs incurred by Halifax for these existing programs may not be considered as REPS compliance costs and may not be included in Halifax's determination of incremental costs. These existing programs were implemented prior to enactment of Senate Bill 3 and the REPS requirement, and the costs incurred for implementation of these existing programs, therefore, were not incurred to comply with the REPS requirements. The Commission believes that it is appropriate to count the energy savings from such existing programs toward REPS compliance, but that it is not appropriate to count any portion of their costs toward the REPS incremental cost cap.

In Senate Bill 3, the General Assembly adopted a complex framework designed to encourage both the development of new electric generating facilities utilizing renewable energy resources and increased investment and deployment of DSM and EE programs, while simultaneously limiting the potential costs to consumers of the new policy mandate. The REPS requirement and its renewable energy mandate, however, is only one section of Senate Bill 3; it is imperative that the Commission read all of the provisions of Senate Bill 3 together in pari materia in order to understand and implement the intent of the General Assembly. In G.S. 62-133.9(b), the General Assembly directed that "[e]ach electric power supplier shall implement demand-side management and energy efficiency measures and use supply-side resources to establish the least cost mix of demand reduction and generation measures that meet the electricity needs of its customers." The challenge in this proceeding is to harmonize this "least cost mix" requirement for Halifax and other EMCs with the requirement that they meet a percentage of their retail sales with more expensive renewable energy generation. The solution to this challenge lies in the definition of "incremental costs."

With enactment of Senate Bill 3, it is reasonable for Halifax to consider implementing new DSM/EE programs to create additional energy savings that may be used to satisfy its REPS obligation. As part of this decision, Halifax should be expected to weigh the costs of implementing new DSM/EE programs with the costs of procuring electric power or RECs from renewable energy facilities. Senate Bill 3 also allows Halifax to meet its REPS obligations with energy savings from DSM and EE programs. Therefore, it may be reasonable for Halifax to incur incremental costs associated with the implementation of new DSM/EE programs comparable to the incremental costs that would be associated with the purchase of renewable energy RECs in order to meet its REPS requirements. In that event, incremental costs for such new DSM/EE programs would appropriately count toward its incremental cost cap.

The Commission, therefore, concludes that there are no incremental REPS compliance costs associated with Halifax's existing DSM/EE programs. These programs were developed prior to enactment of Senate Bill 3, and Halifax is incurring no greater costs simply because the energy savings may now be counted toward REPS compliance. Consistent with the above discussion, Halifax may be allowed to prove in future proceedings that there are incremental costs associated with new DSM/EE programs implemented after enactment of Senate Bill 3 for the purpose of satisfying its REPS obligations. The reasonableness of any incremental costs must be weighed against Halifax's concurrent obligation pursuant to G.S. 62 133.9(b) to provide the "least cost mix of demand reduction and generation measures" for its customers.

IT IS, THEREFORE, ORDERED as follows:

1. That Halifax's 2008 REPS compliance report does not comply with G.S. 62-133.8 and Commission Rule R8-67;

2. That Halifax shall file its Heat Pump Rebates program for approval pursuant to G.S. 62-140(c) and Commission Rule R8-68; and

3. That Halifax shall refile its 2008 and 2009 REPS compliance reports consistent with the findings and conclusions herein on or before September 1, 2011.

ISSUED BY ORDER OF THE COMMISSION.
This the 3rd day of May, 2011.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

sw050311.02

DOCKET NO. EMP-17, SUB 1

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Petition of EnergyUnited Electric Membership	)	ORDER GRANTING
Corporation for Transfer of Renewable Energy	)	REQUEST TO TRANSFER
Certificates from Capricorn Ridge Wind, LLC	)	RENEWABLE ENERGY
	)	CERTIFICATES

BY THE CHAIRMAN: On February 15, 2011, EnergyUnited Electric Membership Corporation (EnergyUnited) filed a petition requesting that the Commission allow the transfer of 150,000 renewable energy certificates (RECs) into the North Carolina Renewable Energy Tracking System (NC-RETS) that have previously been retired in the ERCOT REC tracking system. EnergyUnited stated that the RECs in question are associated with electricity produced by Capricorn Ridge Wind, LLC (Capricorn Ridge), a 550-MW wind facility located in Texas and registered with the Commission as a new renewable energy facility. EnergyUnited's petition included attestations documenting that it purchased (via a third party) 150,000 RECs numbered 00026804 through 00176803 in the ERCOT system. EnergyUnited further stated that the RECs "were not retired for any other organization's REPS compliance in any other state," that they were retired in its name in June of 2009 "solely for the purpose of transfer to North Carolina," and that the transfer "could not occur at the time of the retirement" because NC-RETS did not come online until July 1, 2010.

On March 18, 2011, the Public Staff filed a letter stating that it had completed its review of the request by EnergyUnited: "As a result of our review, we recommend that [EnergyUnited's] petition be granted."

After careful consideration, the Chairman finds good cause to allow EnergyUnited's request. The Chairman notes that Capricorn Ridge is participating in the ERCOT REC tracking system and that the subject RECs were issued and retired prior to the development of NC-RETS.

The Chairman further notes, however, that the Commission has now established a procedure for transferring RECs into NC-RETS from ERCOT, as well as a number of other REC tracking systems, to ensure that such RECs are legitimate and that a credible audit trail links every REC back to its associated renewable energy output. This procedure should be followed in the future to avoid the necessity of additional requests for the transfer of previously retired RECs.

IT IS, THEREFORE, ORDERED that the request by EnergyUnited to transfer into NC-RETS from the ERCOT REC tracking system 150,000 RECs (issued as serial numbers 00026804 through 00176803) that it purchased (via a third party) from Capricorn Ridge and that were retired on its behalf prior to the development of NC-RETS is granted.

ISSUED BY ORDER OF THE COMMISSION.
This the _25th_ day of March, 2011.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Sw032411.01

DOCKET NO. G-9, SUB 581

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-	)	ORDER ON ANNUAL
133.4(c) and Commission Rule R1-17(k)(6)	)	REVIEW OF GAS COSTS

HEARD IN: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on Tuesday, October 5, 2010, at 9:00 a.m.

BEFORE: Commissioner ToNola D. Brown-Bland, Presiding, Commissioners Susan W. Rabon and Lucy T. Allen

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 28202-4003

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

BY THE COMMISSION: On July 30, 2010, pursuant to G.S. 62-133.4(c) and Commission Rule R1-17(k)(6), Piedmont Natural Gas Company, Inc. (Piedmont or the Company), filed the direct testimony and exhibit of Frank H. Yoho, Senior Vice President, Commercial Operations; the direct testimony of Keith P. Maust, Managing Director, Gas Supply and Scheduling; the direct testimony and exhibits of William C. Williams, Vice President, Sales & Delivery Services; and the direct testimony and exhibits of Robert L. Thornton, Director of Gas and Regulatory Accounting, attesting to the prudence of the Company's gas purchasing policies and the accuracy of the Company's gas cost accounting for the 12-month period ended May 31, 2010.

On August 5, 2010, 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, October 5, 2010, set prefiled testimony dates, and required the Company to give notice to its customers of the hearing on this matter.

On August 25, 2010, Piedmont filed corrections to the exhibits of William C. Williams and Robert L. Thornton.

On August 31, 2010, the Attorney General filed his notice of intervention.

On September 16, 2010, Carolina Utility Customers Association, Inc., filed a Petition to Intervene, which was granted by the Commission on September 21, 2010.

On September 20, 2010, the Public Staff filed the direct testimony of Michelle M. Boswell, Staff Accountant, Accounting Division; the direct testimony Kimberly A. Garnett, Utilities Engineer, Natural Gas Division; and the direct testimony of James G. Hoard, Assistant Director, Accounting Division. No other party filed testimony.

On September 22, 2010, the Company filed its affidavits of publication.

On October 5, 2010, the matter came on for hearing as scheduled, and all prefiled testimony and exhibits were admitted into evidence. Company witnesses Yoho, Maust, Williams, and Thornton, and Public Staff witnesses Boswell, Garnett, and Hoard testified at the hearing. No public witnesses appeared at the hearing.

On October 11, 2010, the Company filed a late-filed exhibit of correspondence to the North Carolina Congressional delegation.

On November 16, 2010, the Public Staff filed corrections to the direct testimony of Public Staff witness Hoard.

Based on the testimony and exhibits received into evidence and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

1. The Company is a public utility as defined in Chapter 62 of the North Carolina General Statutes.

2. The Company is engaged primarily in the business of transporting, distributing, and selling natural gas to customers in North Carolina, South Carolina, and Tennessee.

3. The Company 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).

4. The review period in this proceeding is the twelve months ended May 31, 2010.

5. The Company has properly accounted for its gas costs during the review period.

6. During the period of review, the Company incurred total gas costs of $586,246,504.

7. At May 31, 2010, the Company had a credit balance of $16,089,139 in its All Customers Deferred Account and a debit balance of $13,196,148 in its Sales Customers Only Deferred Account.

8. 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.

9. At May 31, 2010, the adjusted balance in the Company's Hedging Deferred Account was a debit balance of $38,973,572.

10. It is appropriate for the Company to transfer the $38,973,572 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 debit balance of $52,169,720.

11. The Company has transportation and storage contracts with interstate pipelines that provide for the transportation of gas to the Company's system and long-term supply contracts with producers, marketers, and other suppliers.

12. 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.

13. The Company's gas purchasing policy and practices during the review period were prudent, and its gas costs during the review period were prudently incurred.

14. The Company should be permitted to recover 100 percent of its prudently incurred gas costs.

15. The Company should implement the temporary increments and decrements recommended by Company witness Thornton as a result of this proceeding.

16. The Company took steps during the review period to begin addressing the Commission's concern regarding a potential conflict of interest regarding Section 5 of the Natural Gas Act (NGA), as expressed in the Commission's Orders on Annual Review of Gas Costs issued in Docket No. G-9, Subs 554 and 569.

17. Piedmont and the Public Staff both support enactment of federal legislation that would modify Section 5 of the NGA, in a manner which provides the Federal Energy Regulatory Commission (FERC) NGA authority that parallels the authority provided to the FERC in the Federal Power Act.

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 Maust, Thornton, and Williams. 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 - 7

The evidence supporting these findings of fact is contained in the testimony of Company witnesses Maust, Thornton, and Williams; the testimony of Public Staff witnesses Boswell, Garnett, and Hoard; and the Commission's Rules.

G.S. 62-133.4 requires that each natural gas utility submit to the Commission information and data for an 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)(a) establishes May 31, 2010, 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, work papers, 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. Piedmont provided revisions to Schedule 2 of Exhibit__(RLT-1) in its corrections to exhibits filing. Company witness Thornton testified that Piedmont incurred gas costs of $586,246,504 during the review period.

Public Staff witness Boswell testified that Company witness Thornton's Exhibit__(RLT-1), as corrected, properly reflects the amount of gas costs incurred by the Company during the review period and the deferred account balances as of May 31, 2010.

Company witness Thornton and Public Staff witness Boswell testified that as of May 31, 2010, the Company had a debit balance of $13,196,148 in its Sales Customers Only Deferred Account and a credit balance of $16,089,139 in its All Customers Deferred Account.

One issue examined closely by the Commission in this proceeding is the appropriateness of the 10% interest rate that is accrued on the Company's Deferred Account balances. In response to questions from the Commission, Public Staff witness Hoard testified that the 10% interest rate is accrued on both credit and debit balances for all gas cost deferred account balances. Witness Hoard testified that, except for the margin decoupling account, which is tied to the rate case treatment of margins, the Company uses the 10% interest rate on all deferred account balances based on the guidance set forth in G.S. 62-130(e). Witness Hoard further testified that the electric utilities use the same authoritative guidance in fuel proceedings for accruing interest on refunds to their customers. He noted that the 10% rate has been in effect since 1991 and that he is comfortable using this interest rate for the gas industry deferred accounts. Hoard further testified that the Public Staff would not want to make a recommendation in this case that could possibly cause an unfortunate precedent for customers in the electric industry. The Commission notes that it specifically authorized the use of the 10% interest rate for Piedmont to accrue interest on its deferred accounts by Order Granting Partial Rate Increase dated July 22, 1991, in Docket No. G-9, Sub 309. Based on the foregoing, the Commission finds that Piedmont's use of the 10% interest rate on its deferred account balances is reasonable.

The Commission concludes that the Company 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). The Commission concludes that based on this evidence, the Company incurred $586,246,504 of gas costs during the review period ended May 31, 2010. In addition, the Commission concludes that the appropriate balances of the Company's deferred accounts as of May 31, 2010, are a debit balance of $13,196,148 in its Sales Customers Only Deferred Account and a credit balance of $16,089,139 in its All Customers Deferred Account.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 8 - 10

The evidence supporting these findings of fact is contained in the direct testimony of Company witnesses Yoho, Maust, and Thornton, and the direct testimony of Public Staff witnesses Boswell and Hoard.

Company witness Thornton stated in his direct testimony that the Company had a total debit balance of $38,973,572 in its Hedging Deferred Account at May 31, 2010. Public Staff witness Hoard testified that these costs were composed of economic losses - closed positions of $57,139,250, premiums paid - closed positions of $23,675, premiums paid - open positions of $3,771,370, brokerage fees and commissions of $83,065, and interest on the Hedging Deferred Account of $13,489,605, less margin requirements of $35,516,366 and interest on the brokerage account of $17,027.

Witness Hoard further testified that the $57,139,250 economic loss on hedging experienced during the review period was attributable to the sale of put options in July, August, September, and October 2008 that were realized during the current review period. Witness Hoard explained that the put options were all sold at strike prices between $6.00 and $7.00 per dekatherm (dt), which at the time of sale were measured as historically low by the Risk Management, Inc. (RMI), price data matrices. He also stated that much of the contemporaneous market intelligence at the time that the puts were sold supported the expectation that prices would trend back up although prices subsequently trended much lower, ultimately resulting in significant economic losses.

One particular area of interest to the Commission in this proceeding is identifying what the Company has done to meet the goals espoused in the Commission's February 26, 2002 Order on Hedging in Docket No. G-100, Sub 84 (Hedging Order). Furthermore, as a result of noting significant differences between the hedging programs of North Carolina's two largest natural gas local distribution companies (LDCs), Piedmont and Public Service Company of North Carolina, the Commission directed Piedmont to provide additional information in this docket:

> In the 2009 ARGC for Public Service Company of North Carolina, Inc. (PSNC) in Docket No. G-5, Sub 509, the Commission ordered PSNC to "provide a detailed explanation of what it is trying to accomplish with its hedging program and how its hedging program is designed to meet the Company's hedging goals," in its next ARGC. The Commission now directs Piedmont to do the same.

Order on Annual Review of Gas Costs in Docket no. G-9, Sub 569 (Sub 569 Order) (February 17, 2010).

In this docket, the Company responded to the Commission's directive through the direct testimony of Company witness Yoho. Witness Yoho testified that Piedmont's goal in engaging in hedging transactions is to mitigate gas cost volatility on behalf of its customers. Witness Yoho stated that, in Piedmont's view, the use of financial instruments to help protect against significant price increases in wholesale gas costs is a beneficial and appropriate strategy to assist Piedmont's customers by managing energy price risk in a wholesale natural gas market that has experienced significant volatility in the last 10 years.

Witness Yoho further noted that Piedmont has consistently stated since the inception of its hedging program that a hedging strategy based on reducing volatility will most likely result in added costs to customers over time. Witness Yoho then explained that this is because the protection provided by hedging comes at a cost which customers pay to have protection from volatility. Witness Yoho compared this situation with a consumer purchasing an automobile, homeowners, or health insurance policy.

Company witness Yoho also testified that it is important to understand that a hedging strategy that seeks to mitigate volatility is completely different from a speculative program which involves an attempt to "beat the market." He stated that these two types of programs have very different goals. The goal of Piedmont's hedging program is to mitigate volatility (i.e., reduce the variability in the price of gas paid by its customers), whereas the goal of a speculative program is to generate economic gains. Witness Yoho stated that Piedmont believes that market speculation is not a proper pursuit for an LDC.

Company witness Yoho testified that Piedmont pursues its hedging activities with the assistance of RMI, an outside hedging consultant; that its hedging program is designed to hedge future gas costs based on both a comparison with historic norms for natural gas prices and the proximity of the period to be hedged; and that Piedmont's hedging program is administered internally and is overseen by Piedmont's Energy Price Risk Management Committee (EPRMC), a committee composed of the Company's Chief Financial Officer, Chief Risk Officer, Chief Ethics and Compliance Officer, and others. Witness Yoho also stated that "depending on where the market is going," the EPRMC may make a decision to change the plan or may at least recommend changing the plan.

Witness Yoho stated that Piedmont's hedging program is a very rational approach to providing protection to customers from wholesale price volatility. It has been developed with significant and ongoing assistance from outside experts and is closely supervised by Piedmont senior management and the EPRMC. Piedmont continually evaluates the operation of the program and the financial instruments utilized under the program. According to a consultant retained by Piedmont, Mr. Bruce Henning of ICF International, Piedmont's hedging plan is consistent with industry best practices and properly designed to create an adequate level of price protection for its customers. Company witness Maust testified that Piedmont's Hedging Plan accomplished its goal of providing an additional tool to reduce gas cost volatility to customers in North Carolina that purchase gas from Piedmont.

The Commission's Sub 569 Order also ordered Piedmont to make a filing stating its position as to whether it had future intentions to engage in the sale of put and call options under its hedging program and explaining its position in that regard. On April 16, 2010, Piedmont filed its Statement of Intent Regarding Sales of Put and Call Options and stated that it will not engage in the sale of put and call options under its Hedging Plan on a going forward basis. Witness Maust testified that the Company made the decision during the review period to cease selling puts and calls as part of its hedging program. He stated that this change will allow the customer to participate in all downward price market movement while eliminating any market cap on price protection. He further stated that although this change will lower the level of initial price protection on the high side, it will also eliminate any potential extraordinary losses in the hedging plan. Witness Maust testified that the Company also continues to utilize storage as a physical hedge to stabilize costs for its customers. He further indicated that the Company's Equal Payment Plan, PGA benchmark price, and deferred cost accounting mechanisms also have a smoothing effect on gas price volatility.

Company witness Maust further testified that the Company has also reduced the maximum and minimum percentages of its normalized sales to be hedged from 60% and 30% to 45% and 22.5%, respectively. He stated that the Company believes that the increased gas supply deliverability, caused primarily by the prolific increase in shale-related natural gas production, warranted a reduction in the level of protection necessary to shield the Company's customers from today's reduced market price volatility.

Company witness Yoho stated that the Company has reduced from 24 months to 12 months the period in advance that Piedmont will hedge. Witness Yoho testified, "There is a cost to hedge and it goes to two things and two things drive the cost; volatility and time." He further testified that "because of the cost implications of going beyond 12 months for the hedging plan we thought it was better to bring it back to 12 months where we saw more the spike volatility."

Public Staff witness Hoard testified that the Public Staff's review of the Company's hedging activities is an ongoing multidiscipline team effort, which includes analysis and evaluation of the Company's monthly hedging deferred account reports, detailed source documentation, workpapers supporting maximum targeted hedge volumes, periodic reports on the status of hedge coverage, periodic reports on the market values of the various financial instruments used by the Company, monthly Hedging Program Status Reports, monthly reports reconciling the Hedging Program Status Report and the hedging deferred account report, minutes from the EPRMC and Board of Directors meetings, reports and correspondence from the Company's internal and external auditors, hedging plan documents, communications with Company personnel regarding key hedging events, and the Company witnesses' testimonies and exhibits in the annual proceedings. Witness Hoard concluded that Piedmont's hedging activities were reasonable and prudent and that the $38,973,572 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.

Public Staff witness Hoard testified that the Company has experienced mixed results from a gain and loss perspective since it implemented its hedging program in 2003. Witness Hoard testified that, since the inception of its hedging program in 2003, Piedmont has paid $95.1 million in premiums and incurred economic losses of $65.2 million, and that these hedging costs represented approximately 5% of its gas supply costs or $0.33/dt. Witness Hoard further testified that most of the economic losses were incurred during the 2009 and 2010 review periods and that these losses resulted from the sale of puts. Witness Hoard also stated that Piedmont reported to the Commission on April 16, 2010, that it had determined to discontinue selling puts.

Witness Hoard concluded that Piedmont's decision to hedge its gas costs was consistent with the Commission's conclusions regarding the hedging option, as set forth in the Commission's Hedging Order, wherein it stated:

> In summary, the Commission concludes that hedging is an option that must be considered in connection with an LDC's gas purchasing practices. An LDC's decision to make no effort to mitigate price spikes -- including a decision not to hedge -- would be a decision subject to review in the LDC's annual gas cost prudency review proceeding just as much as a decision to hedge.

Another hedging issue examined during the proceeding involved a comparison of the various features and characteristics of the Public Service Company of North Carolina, Inc. (PSNC), and Piedmont hedging plans. Public Staff witness Hoard testified that as a result of Piedmont's decision not to sell puts and the 6% cost cap on the purchase of hedging instruments set forth in its hedging plan, Piedmont may not be able to purchase calls as close to market prices as it had been; however, witness Hoard stated that the change should eliminate any potential for extraordinary losses in the hedging plan. The Commission questioned witness Hoard as to whether the Public Staff supported recommending a change in Piedmont's 6% cost cap to the 10% cost cap reflected in PSNC's hedging plan. Witness Hoard testified that it was a matter of balancing the different features in the hedging plans. Witness Hoard testified that PSNC, for example, hedges a lower portion of its supply than Piedmont. PSNC hedges 25% and Piedmont hedges 22.5% to 45%, and Piedmont treats storage volumes differently in its method for determining its hedge volumes. Witness Hoard testified that in the end, because of the plan differences regarding the volumes hedged, the 10% cost cap for Piedmont would not be the same as the 10% cost cap for PSNC. Similarly, Piedmont witness Yoho testified in response to Commission questions that PSNC hedges twice the dollar amount but half the volume, and as result, the two companies end up in a very similar place in terms of the dollars allocated. Public Staff witness Hoard testified that Piedmont has scrutinized its program to see what the proper balance should be and that he believes that the 6% cost cap is the appropriate amount to spend at this time.

In cross-examining Witness Yoho, the Attorney General's Office (Attorney General) stated that it was under the impression that Piedmont used the same hedging program in South Carolina, but in South Carolina the program was pre-approved, such that the terms under which Piedmont hedges are approved in advance. Witness Yoho confirmed the Attorney General's understanding. The Attorney General then asked if Piedmont could modify or suspend its plan in North Carolina and not in South Carolina. Company witness Yoho responded that "Separate accounts currently run, we think, very similar markets and customers and so it makes sense to have them run similarly." He further explained that, "...if we needed to modify, one is not dependent upon the other. The dollars...and volumes are kept in separate accounts. So if we so chose, we could do them totally different."

The Commission finds and concludes that Piedmont's hedging activities during the review period were reasonable and prudent and that the $38,973,572 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 debit balance of $52,169,720.

As was stated in the Order in Docket No. G-100, Sub 84, the Commission assures Piedmont that the prudency of LDC hedging decisions will be evaluated on the basis of the information available to them at the time their hedging decisions are made, not on the basis of the outcomes of their hedges. However, because the Commission perceives that the Company's hedging decisions are determined in large part by a model based on historical statistics in the hedging program, the Commission is interested in learning more about information other than the guidance from the RMI model itself that Piedmont uses in making its hedging decisions and in learning about when and how Piedmont allows deviations from the results of its RMI model. The Commission is particularly interested in learning whether Piedmont uses forward-looking market projections by accepted experts in the natural gas field and, if it does, how such projections are used.

Accordingly, the Commission requests Piedmont to file testimony in its next annual review proceeding addressing other information, apart from the RMI model guidance, that has been or that may be used in its hedging program to determine whether deviation from RMI model guidance is in order or should be allowed. The Commission understands that discipline is a part of any hedging program, and that it is usually appropriate in a hedging program to obtain some level of price insurance regardless of broad market trends. Therefore, the Commission seeks this requested testimony, not to focus on the Company's day to day decision-making or on the outcomes of hedging compared to market performance, but to get a clearer picture of what Piedmont does, other than act on the information generated by its model, in making its hedging decisions and whether Piedmont, in any matter, analyzes and reacts to or accounts for projections and broad market trends.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 11 - 14

The evidence supporting these findings of fact is contained in the testimony of Company witnesses Maust and Williams and Public Staff witness Garnett.

Company witness Maust 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 Maust testified that all of these components are interrelated and that the Company weighs the relative importance of each of these five factors in establishing its entire supply portfolio.

Witness Maust 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 Piedmont's 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, with market-based commodity prices tied to indices published in industry trade publications. These firm contracts range in term from one year (or less) to terms extending into 2013. Longer term contracts may provide for periodic reservation fee renegotiations. 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.

Witness Maust described how the interrelationship of the five factors affects the Company's construction of its gas supply 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 FERC proceedings affecting 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 Maust testified that the Company's greatest challenge in applying its best cost policy is in dealing with future uncertainties in a dynamic national and regional energy market. Future demand for gas is affected by economic conditions, customer conservation efforts, weather patterns, regulatory policies, and industry restructuring in the energy markets. Future availability and pricing of gas supplies is affected by overall demand, oil and gas exploration and development, pipeline expansion projects, and regulatory policies and approvals. Witness Maust further stated that the Company did not make any changes in its best cost gas purchasing policies or practices during the test period.

Witnesses Maust and Williams 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 use of its system, and utilizing the flexibility within its existing supply and capacity contracts to purchase and dispatch gas and to release capacity in the most cost effective manner.

Company witness Maust also testified regarding the current domestic natural gas supply situation and the various pricing alternatives available, such as fixed prices, monthly market indexing, and daily spot market pricing.

Company witness Williams testified regarding the market requirements of Piedmont's North Carolina customers and the acquisition of capacity to serve those markets. The Company has experienced a reduction in weather normalized usage per customer due to several reasons, including the increased efficiency of new appliances used by new customers, the replacement of old equipment by existing customers, and conservation measures employed by customers directly resulting from increased wholesale natural gas prices and their awareness of such increased prices. Piedmont and the natural gas industry have not, however, seen evidence that conservation and/or reduced usage occurs during the coldest of days.

Witness Williams testified about what he called a "reverse hook pattern." He testified that "data seems to indicate that as temperatures drop, the customer's behavior is to conserve for the first few days of colder temperatures before turning up the thermostat. Once adjusted to a warmer setting, customers appear to become less focused on conservation and more focused on comfort and leave the thermostat at the warmer level for a few days even as temperatures start to moderate." For that reason, witness Williams testified, Piedmont will continue to utilize a conservative approach in its forecast of demand on those days because Piedmont wants to make certain that it has a secure supply available to those customers. Piedmont is currently evaluating capacity options available for the 2013-2014 winter season and beyond.

Witness Williams was examined by the Commission regarding the Company's design day determinations. The Commission notes that its December 11, 1997 Order on Annual Review of Gas Costs in Docket No. G-9, Sub 393, addressed Piedmont's modification of its design day criteria from 55 degree days to 53 degree days with a 5% reserve margin. The Sub 393 Order stated that Public Staff witness Davis testified that

> the purpose of this reserve margin was to supplement the design day criteria of 53 heating degree days (HDD), which represents 12° Fahrenheit in average temperature for the system. According to Mr. Davis, other gas utilities in the State use design criteria of 55 HDD for planning without a reserve margin. He stated that using a 10,000 dt/day reserve margin with a 53 HDD design day is approximately the same as using a 54 HDD design day, which is well within design tolerances and an acceptable approach. For this reason, he did not question the reasonableness of Piedmont's use of a 10,000 dt/day reserve margin for capacity and supply planning during the review period. He stated, however, that the Public Staff will continue to review the matter on a case-by-case basis in future proceedings.

The Commission concluded that Piedmont's approach for design day demand determination in the Sub 393 docket was reasonable.

In the instant docket, it was pointed out that the design temperature is now 11.3° with a 5% reserve margin (Williams Exhibit_ WCW-1), and at the time of the Sub 393 docket, the design temperature was 12° with a 5% reserve margin. Witness Williams was asked if the Company needed to modify its average temperature that is utilized in the determination of its customers design day requirements. Witness Williams responded "no" because "the reserve margin plus the design temperature, the way it's set up, operates in a way that really sets us up to protect for 55 degree day."

Public Staff witness Garnett testified that she had reviewed the testimony and exhibits of the Company's witnesses, monthly operating reports, and 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, Ms. Garnett testified that the Company's review period gas costs were prudently incurred.

No other party presented evidence on these matters.

Based on the foregoing, the Commission concludes that the Company's gas purchasing policies and practices during the review period were prudent and that its gas costs during the review period were prudently incurred and should be recovered.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The evidence supporting this finding of fact is contained in the testimony of Company witness Thornton and Public Staff witness Garnett.

Company witness Thornton stated in his testimony that the Company proposed to place temporary rate elements in rates to adjust amounts held in its deferred accounts.

Public Staff witness Garnett testified that she had reviewed the temporary rate decrement applicable to the All Customers Deferred Account balance proposed by Company witness Thornton, as reflected in Exhibit__(RTL-3), and agreed with the calculations. Public Staff witness Garnett further testified that she had reviewed the temporary rate increment applicable to the Sales Customers Only Deferred Account balance proposed by Company witness Thornton, as reflected in Exhibit__(RTL-4), and agreed with the calculations.

No other party presented evidence on this issue.

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 in Docket No. G-9, Sub 554, and implement the temporary decrements applicable to the All Customers Deferred Account recommended by Company witness Thornton and Public Staff witness Garnett, as set forth in Company witness Thornton Exhibit__(RLT-3), and to remove the temporary rates that were continued for the Sales Customers Only Deferred Account in Docket G-9, Sub 554, and implement the temporary increments applicable to the Sales Customers Only Deferred Account recommended by Company witness Thornton and Public Staff witness Garnett, as set forth in Company witness Thornton Exhibit__(RLT-4).

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 16 - 17

The evidence for these findings of fact is contained in the testimony of Piedmont witness Yoho and Public Staff witness Hoard.

In Piedmont's 2008 annual review of gas costs proceeding, Docket No. G-9, Sub 554, Company witnesses Maust and Williams were asked by the Commission about Piedmont's purchase of capacity from Pine Needle LNG Company, LLC (Pine Needle), a FERC-regulated entity in which an affiliate of Piedmont has an ownership interest. In its Sub 569 Order, the Commission expressed concern that the potential for conflict of interest exists due to the relationship between Piedmont as a customer and as an equity investor in Pine Needle and Hardy Storage, LLC (Hardy), two FERC-regulated natural gas utilities, stating that "Piedmont has placed itself in a position in which a quirk in the federal law [NGA] benefits its shareholders and harms its ratepayers." The Commission further stated that "such an arrangement by an LDC calls for an exceptional effort on the part of the LDC to show that it is acting to protect the interests of ratepayers as it would if it were not an equity owner."

In the current annual review of gas costs proceeding, Company witness Yoho testified that while Piedmont recognizes "the concerns of the Commission regarding potential conflicts of interest that could be involved in these types of investments, Piedmont is extremely careful in practice to avoid any conflicts and, more to the point, Piedmont believes that its investments in these types of projects actually assists in keeping costs down for North Carolina natural gas customers by making sure competitive projects come to fruition." Witness Yoho offered five points to more fully explain Piedmont's position. First, Piedmont's practice of making purely equity investments in joint venture projects creates a separation between day-to-day operations and regulation of these projects and Piedmont. Second, Piedmont maintains a strict separation between the personnel who are charged with managing its equity investments and those pursuing the interests of Piedmont's customers at FERC, as required by Piedmont's internal policies and codes of ethics and also FERC policies and regulations. Third, Piedmont actively and strenuously pursues the interests of its customers in proceedings involving Hardy and Pine Needle before FERC, frequently with greater zeal than other customers that have no equity investments in these entities. Fourth, Piedmont's participation in such projects helps assure that they will actually be constructed to the benefit of Piedmont's customers. Finally, in each case where Piedmont has subscribed to capacity of Pine Needle and Hardy, that capacity was the "best cost" (and least cost) capacity available to meet Piedmont's customer needs at the time.

Witness Yoho further testified that the Company shares the Commission's concern over the lack of parity between the FERC's refund authority under Section 5 of the NGA as compared to the Federal Power Act and also with the potential effects of the "refund floor" mechanism under Section 4 of the NGA. He stated that Piedmont's experience suggests that NGA Section 5 complaint or show cause proceedings are somewhat inhibited by the fact that the FERC has only prospective ratemaking authority in those proceedings whereas under the Federal Power Act, the FERC can order rate changes as of the date of the complaint or show cause proceeding. Piedmont has also observed that the refund floor mechanism under Section 4 of the NGA can come into play from time-to-time in natural gas rate cases where a jurisdictional entity has declining rate base and the potential application of that mechanism is a factor that must be considered in efforts to settle those proceedings. Witness Yoho stated that both of these issues are matters of federal law that require legislation to change and that Piedmont has written letters to all members of the North Carolina Congressional delegation representing Piedmont's service territory discussing the Section 5 issue and urging those delegates to support reform of Section 5 of the NGA, as well as actively engaged key members of Congress as this issue is coming up for vote in various committees and possibly the floor of the Senate. Piedmont provided a sample of the letters as a late-filed exhibit on October 11, 2010.

Public Staff witness Hoard, in explaining the refund floor provision of the NGA, testified that Section 4 of the NGA allows a company covered by the NGA to request a rate increase and allows the company, after a suspension period, to place its proposed increase in effect under bond and subject to refund. Witness Hoard testified it is his understanding that Section 4(e) of the NGA has been interpreted as establishing a floor under refunds to customers at the rates in existence when the Section 4 proceeding was initiated (rate refund floor). He further explained that Section 5 of the NGA allows interested parties to file a complaint seeking rate decreases from companies covered by the NGA; however, Section 5 of the NGA has no provision for refunds, and parties, therefore, are limited to prospective relief. Because of a recent trend towards the incremental pricing of new projects, including single asset projects, such as Pine Needle and Hardy, certain companies covered by the NGA are experiencing declining rate bases, which can result in higher effective rates of return and, consequently, have no incentive to file rate cases to lower their rates. Witness Hoard noted that these companies effectively earn a return on a level of rate base investment that no longer exists because some rate base investment has been previously recovered by the company through depreciation expense.

Witness Hoard also testified that the rate refund floor gives companies regulated by the NGA an unfair advantage over parties seeking lower rates in litigation or negotiations, since any reduced rates would only go into effect after the case is resolved, thereby decreasing the incentive for the companies to settle a proceeding wherein rates will be reduced. He testified that the lack of refunds under Section 5 of the NGA means that if an outside party successfully argues that a company covered by the NGA is charging rates that are not just and reasonable, the only relief is prospective and the company is allowed to retain money collected using rates found to be unjust and unreasonable from the time the Section 5 filing is made until the case is resolved.

Witness Hoard further testified that the unfairness related to the lack of a refund mechanism under Section 5 of the NGA and the requisite need for a legislative fix was recently addressed in the dissent of FERC Chairman Jon Wellinghoff issued June 8, 2010, regarding the FERC's Order on Motion to Terminate in Northern Natural Gas Company, 131 F.E.R.C. ¶ 61,178 (2010), wherein Chairman Wellinghoff stated, "[t]his [lack of refund remedy] is patently unfair and for this reason I support legislative changes providing for NGA refund authority paralleling that provided to the Commission in the Federal Power Act." Witness Hoard testified that under the Federal Power Act, the FERC shall set the refund effective date not earlier than the date of the filing of such complaint, nor later than 5 months after the filing of such complaint. He concluded by testifying that the Public Staff supports such a change to Section 5 of the NGA and is prepared to join and assist the Commission and the North Carolina LDCs in supporting its enactment.

Public Staff witness Hoard testified that Piedmont participates as a customer and an equity investor (through affiliates) in three stand-alone natural gas utilities, Cardinal Pipeline Company, LLC (Cardinal), Pine Needle, and Hardy. As previously discussed, two of these utilities, Pine Needle and Hardy, are regulated by the FERC, and the other, Cardinal, is regulated by this Commission. As to the Commission's perceived conflict of interest, witness Hoard observed that any perceived or potential conflict associated with those relationships, as well as the declining rate base problem discussed above, has existed from the beginning of those relationships, and the Public Staff expects Piedmont to maintain proper separation of its customer and ownership functions. He testified that no Piedmont personnel are directly involved in the day-to-day management of Cardinal, Pine Needle, or Hardy, and that Piedmont has designated specific Piedmont officers to serve in oversight roles to monitor and protect Piedmont's equity investments in these entities.

The Commission acknowledges that Piedmont has taken steps during the review period to begin to address the Commission's concerns regarding a potential conflict of interest regarding Section 5 of the NGA, as expressed in the Commission's Orders on Annual Review of Gas Costs issued in Docket No. G-9, Subs 554 and 569. The Commission also acknowledges that the Public Staff supports enactment of federal legislation that would modify Section 5 of the NGA in a manner which provides the FERC with authority under the NGA that parallels the authority provided to the FERC in the Federal Power Act. The Commission expects Piedmont to use its best efforts to change the law in a manner that is adequate to protect the interests of its ratepayers and directs Piedmont to report on its further efforts to the Commission in its next annual review of gas costs.

IT IS, THEREFORE, ORDERED as follows:

1. That the Company's accounting for gas costs during the 12-month period ended May 31, 2010, under review in this proceeding is approved.

2. That the Company is authorized to recover 100% of its gas costs incurred during the period of review covered in this proceeding.

3. That, in its next annual review of gas costs, Piedmont shall report to the Commission on its further efforts to amend the Natural Gas Act as discussed herein;

4. That, in its next annual review of gas costs, Piedmont shall file testimony addressing the information, other than the output of its RMI model, that it uses in its hedging program and addressing when and how it allows deviations from the guidance provided by its model. Such testimony shall address whether Piedmont uses forward-looking market projections by accepted experts in the natural gas field and, if so, how such projections are used.

5. That the Company shall remove the existing temporaries that were implemented in Docket No. G-9, Sub 569, and implement the temporary rate decrements and increment 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.

6. That Piedmont shall give notice to its customers of the rate changes allowed in this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the _18th_ day of January, 2011.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

kh011811.01

DOCKET NO. G-5, SUB 524

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 9, 2011, at 10:00 a.m., in Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner Susan W. Rabon, Presiding, Commissioners William T. Culpepper, III and Bryan E. Beatty

APPEARANCES:

For Public Service Company of North Carolina, Inc.:

B. Craig Collins, SCANA Corporation, MC-C222, 220 Operation Way, Cayce, South Carolina 29033-3701
Mary Lynne Grigg, McGuireWoods, LLP, 2600 Two Hanover Square, 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 27699-4326

BY THE COMMISSION: On June 1, 2011, 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 Terina H. Cronin, General Manager, Gas Supply & Commercial and Industrial Marketing, in connection with the annual review of PSNC's gas costs for the twelve-month period ended March 31, 2011.

On June 8, 2011, 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 9, 2011, set prefiled testimony dates, and required the Company to give notice to its customers of the hearing on this matter.

On July 13, 2011, the Attorney General's Office filed a Consumer Statement of Position Letter with the Commission.

On July 25, 2011, the Public Staff filed the direct testimony of Julie G. Perry, Supervisor of the Natural Gas Section, Accounting Division; and the direct testimony and exhibits of Catherine L. Eastwood, Staff Accountant, Accounting Division; and Jan A. Larsen, Public Utilities Engineer, Natural Gas Division.

On July 28, 2011, the Company filed its Affidavits of Publication.

On July 29, 2011, PSNC filed its Motion for the Admission of B. Craig Collins to appear pro hac vice in this proceeding, and that motion was allowed by Commission Order dated August 2, 2011.

On August 5, 2011, PSNC filed Joint Rebuttal Testimony of Candace A. Paton, Terina H. Cronin, and Rose M. Jackson, General Manager, Supply & Asset Management for SCANA Services, Inc.

No other party filed testimony.

On August 9, 2011, the matter came before the Commission as scheduled and all prefiled testimony and exhibits were admitted into evidence. The PSNC and Public Staff witnesses all testified at the hearing. No public witnesses appeared at the hearing.

On August 16, 2011, the Public Staff filed the late-filed exhibit of witness Larsen that provided the effect of the proposed temporary increments/decrements on a typical residential and small general service customer's bill.

On September 30, 2011, the Public Staff filed a Proposed Order and PSNC filed a Proposed Order and Brief.

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 483,000 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 for this proceeding is the twelve months ended March 31, 2011.

5. During the period of review, PSNC incurred total gas costs of $281,379,428, which was composed of demand and storage charges of $71,213,096, commodity gas costs of $209,967,314, and other gas costs of $199,017.

6. 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.

7. PSNC has a portfolio of long-term and supplemental short-term supply agreements with a variety of suppliers, including producers and independent marketers.

8. The gas costs incurred by PSNC during the review period were prudently incurred.

9. The Company should be allowed to recover 100% of its prudently incurred gas costs.

10. PSNC has pursued secondary market transactions, which have resulted in a total of $56.4 million in credits to customers from April 2003 through March 2011, of which $6.6 million is directly attributable to bundled sales.

11. 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 a credit of $7,942,947, to its All Customers Deferred Account.

12. The Public Staff recommended an adjustment related to secondary market transactions that produced a debit balance of $8,973,066 in the All Customers Deferred Account as of March 31, 2011.

13. The Public Staff's proposed accounting adjustment reassigning costs related to delivered gas purchases to secondary market transactions is inappropriate and should not be made in this proceeding.

14. PSNC's secondary market transaction activities during the review period were reasonable and prudent.

15. As of March 31, 2011, the Company had a credit balance of $6,545,727 in its Sales Customers Only Deferred Account and a debit balance of $9,411,158 in its All Customers Deferred Account.

16. The Company has properly accounted for its gas costs incurred during the review period.

17. PSNC's hedging activities during the review period were reasonable and prudent.

18. As of March 31, 2011, the Company had a debit balance of $5,731,901 in its Hedging Deferred Account.

19. It is appropriate to transfer the $5,731,901 debit balance from the Hedging Deferred Account to the Sales Customers Only Deferred Account. Subsequent to the transfer, the Sales Customers Only Deferred Account would have a net credit balance of $813,826 as of March 31, 2011.

20. As a result of this proceeding, the Company should implement the new temporary increments applicable to the All Customers Deferred Account and the new temporary decrement applicable to the Sales Customers Only Deferred Account as proposed by Company witness Paton.

21. As a result of this proceeding, the Company should remove the fixed gas cost collection rates as approved in its last general rate case, G-5, Sub 495, and implement the fixed gas costs collection rates as proposed by Witness Paton and concurred by Public Staff witness Larsen in this docket.

22. Based on PSNC's Code of Conduct Section II.E.5, it is appropriate for PSNC to file with the Commission for approval the Base Contract For the Sale and Purchase of Natural Gas dated April 1, 2005, between PSNC and SCANA Energy Marketing, Inc., a gas marketing affiliate.

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

The evidence for these findings of fact is contained in the testimony of PSNC witnesses Cronin and Paton and Public Staff witness Eastwood. The findings are based on G.S. 62-133.4 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 Cronin 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 Cronin 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). Public Staff witness Eastwood 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, 2011.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5 – 9

The evidence supporting these findings of fact is found in the direct testimony of PSNC witnesses Cronin and Paton and Public Staff witnesses Eastwood and Larsen.

PSNC witness Paton's filed exhibits reflecting demand and storage costs of $71,213,096, commodity costs of $209,967,314, and other gas costs of $199,017 for a total of $281,379,428.

Public Staff witness Eastwood testified that, based on Public Staff witness Perry's recommended adjustment for secondary market transactions, the Public Staff's adjusted total cost of gas for the review period ending March 31, 2011, is $280,947,428, which is comprised of $69,485,100 of demand and storage charges, $209,967,314 of commodity costs, and $1,495,014 of other costs.

PSNC witness Cronin testified that approximately 44% 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 Cronin, 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.

Witness Cronin further testified that the most appropriate description of PSNC's gas supply policy would be a "best cost" supply strategy, which is based on three primary criteria: supply security, operational flexibility, and cost of gas. PSNC witness Cronin indicated that security of supply is the first and foremost criterion. She stated that supply security is especially important to the Company's firm customers, who have no alternative fuel source, and is supported by PSNC's diverse portfolio of suppliers, receipt points, purchase quantity commitment and terms. Witness Cronin elaborated that potential suppliers are evaluated on a variety of factors, which include past performance, creditworthiness, available terms, gas deliverability options, and supply location.

Witness Cronin 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 its industrial customers, combined with their ability to switch to alternate fuels. She noted that PSNC's gas supply portfolio as a whole must be capable of handling the monthly, daily, and hourly changes in the Company's demand needs. She further testified that operational flexibility is obtained through PSNC's gas supply agreements having different purchase commitments and swing capabilities, and also through injections into and withdrawals from storage.

In regard to the third criterion, cost of gas, witness Cronin 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 PSNC routinely requests gas supply bids from its suppliers to help ensure PSNC is getting the most cost-effective proposals. Company witness Cronin further stated that PSNC continues to incorporate these factors into the development of an overall gas supply portfolio to meet its customers' needs.

Witness Cronin stated that the majority of PSNC's interstate pipeline capacity is obtained from Transcontinental Gas Pipeline Company, LLC (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. The other interstate transportation providers with whom PSNC has contracts are Dominion Transmission, Incorporated; Columbia Gas Transmission Corporation; and East Tennessee Natural Gas Company. In addition, PSNC has storage service agreements with Dominion Cove Point LNG, LP; Saltville Gas Storage Company, LLC; Texas Gas Transmission, LLC; and Pine Needle LNG Company, LLC.

Witness Cronin further testified that PSNC has developed a gas supply portfolio of long-term supply agreements and supplemental short-term supply agreements with a variety of suppliers. PSNC's gas supply agreements include the following: base load 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, and no-notice contracts that provide the flexibility to increase or decrease volumes on a daily basis. According to witness Cronin, PSNC had approximately 235,000 dekatherms per day (dts/day) under term contracts with eight producers and three independent marketers as of November 1, 2010, 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 sensitive.

Witness Cronin testified that the gas supply and capacity portfolio that the Company has developed provides it the flexibility to meet its market requirements in a secure and cost-effective manner.

In addition, witness Cronin identified the following activities that PSNC has engaged in to lower gas costs while maintaining security of supply and delivery flexibility in order to accomplish its "best cost" policy:

NATURAL GAS – MISCELLANEOUS

1. PSNC continues to evaluate various Firm Transportation 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 cost effectively purchase and dispatch gas and to pursue and capture opportunities for capacity release and other secondary market transactions.

3. PSNC participated in matters before the Federal Energy Regulatory Commission (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.

Public Staff witness Larsen stated that he 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. He further testified that PSNC secures its gas supply at monthly index market prices and engages in hedging of a portion of its firm market gas supply.

Witness Larsen also stated that he reviewed other information received pursuant to data requests to determine PSNC's gas requirements for the future. He concluded that PSNC prudently incurred its gas costs for the twelve-month review period ending March 31, 2011, although PSNC did incur some high priced gas supply and capacity during the winter period as discussed below.

Witness Cronin testified that, following the Commission's Order on Annual Review of Gas Costs in Docket No. G-5, Sub 516, PSNC began to develop a strategy for amending the NGA to give FERC the same authority under Section 5 that it has under the Federal Power Act (FPA). PSNC then began to coordinate its lobbying efforts with Piedmont Natural Gas Company, Inc. (Piedmont). She further stated that on April 19, 2011, as a result of these efforts, representatives of both PSNC and Piedmont met with the Deputy District Director for Representative Sue Myrick of North Carolina's 9th Congressional District. Representative Myrick is also Vice Chairman of the Energy and Commerce Committee of the US House of Representatives. At the meeting, both companies discussed their concerns and delivered a letter requesting that amendment of the NGA be considered during the current legislative session. Additionally, witness Cronin stated, PSNC's federal affairs director subsequently discussed the issue with Representative Myrick in Washington, D.C. She elaborated that the companies decided that this strategy is currently the best approach to seek a change in the law. Both companies believed it was logical to work with Representative Myrick to implement this strategy, due to her position on the House Energy and Commerce Committee. Finally, witness Cronin added that PSNC intends to continue to take appropriate steps designed to accomplish the desired amendment of the NGA.

The Commission's order in Docket No. G-5, Sub 516 stated, "The Commission expects PSNC to use its best efforts to change the law in a manner that is adequate to protect the interests of its ratepayers and directs PSNC to report on its efforts to the Commission in its next annual review of gas costs." The letter to Representative Myrick introduced as Cronin Exhibit 2 urged Representative Myrick, "to support legislation that would amend the Natural Gas Act to bring parity to the manner in which natural gas and electric consumers are treated when it comes to the ability of the Federal Energy Regulatory Commission (FERC) to review and timely set just and reasonable rates."

With regard to achieving parity between the NGA and the FPA, the Commission understands that the key difference between those acts concerns the availability of refunds when a complaint proceeding results in reduced rates. Section 5 of the NGA authorizes FERC to set just and reasonable gas rates on its own initiative or as the result of a complaint proceeding filed by a state commission or customer. However, Section 5 only authorizes FERC to set rates prospectively. The corresponding Section of the FPA is Section 206. The FPA, as amended in the Regulatory Fairness Act of 1988, provides for limited refunds in proceedings initiated under Section 206.

The refunds available under Section 206 are limited to 15 months, unless the FERC finds that the electric utility has engaged in dilatory behavior. While 15 months may have been a reasonable period of time to expect a Section 206 complaint proceeding against an electric utility to be litigated before the FERC when the Regulatory Fairness Act was passed in 1988, the Commission has serious doubts as to whether an NGA Section 5 complaint proceeding against a natural gas company could be fully litigated before the FERC in only 15 months at the present time. Therefore, the Commission is concerned that amending the NGA to simply achieve parity with the treatment given the customers of electric utilities under the FPA might well still leave natural gas customers at a sharp disadvantage to the FERC-regulated gas companies.

In PSNC witness Cronin's direct testimony, she was asked, "Are you aware of any other changes in PSNC's contracted storage capacity." Her response was limited to a discussion of Transco's filing at the FERC to partially abandon storage deliverability from its Washington Storage Field so as to reduce, by approximately 10.5% on a pro rata basis, the daily withdrawal entitlements for service under Rate Schedule WSS-Open Access.

Pursuant to our statutory responsibilities under G.S. 62-48(a), the Commission is aware that, during the review period in this docket, problems were experienced at Transco's Eminence

Storage Field in Covington County, Mississippi. The Eminence Storage Field consists of seven salt dome caverns. On December 26, 2010, Cavern 3, which has a capacity of 3 BCF (including working storage and cushion gas) experienced a large pressure drop. Transco determined that gas was leaking from the cavern. Transco flared the gas in Cavern 3. On January 31, 2011, Transco filed with FERC an Advance Report of Emergency Blanket Certificate Activities. It stated that it intended to undertake certain activities to stabilize Cavern 3 and investigate the cause of the leak. It further stated that the effort to remediate Cavern 3 would take approximately eleven months and cost between $12 million and $25 million and a delay might possibly cause "further degradation of the storage field."

On July 15, 2011 -- after the review period in this docket -- Transco filed an additional report in CP11-73. Transco stated that "further emergency reconstruction activities have been required to stabilize Cavern 3 and other caverns at the Eminence Storage Field." It revealed that the integrity of Caverns 1 and 2 have also been "compromised." Gas was removed from Cavern 1 and it was filled with water in March. Transco now intends to install facilities to capture remaining gas rather than flaring it and expects the facilities to be installed by October 2011. Transco informed the FERC that it intends to abandon Caverns 1, 2, 3 and 4 and the associated deliverability and storage capacity at Eminence Storage Field.

During the review period, PSNC paid $992,347 to Transco in monthly demand charges for "ESS Demand and Capacity" (Paton Exhibit 1, Schedule 2, line 21) and paid $998,796 to Transco in monthly demand charges for "Eminence Demand and Capacity" (Paton Exhibit 1, Schedule 2, line 22). The Commission expects PSNC to be active protecting the interests of ratepayers and shareholders in CP11-73 and other FERC dockets which may apply to this matter.

Because, as discussed below, the Commission finds that the secondary market transaction adjustment proposed by the Public Staff in this proceeding is not appropriate, the Commission, after careful consideration, concludes that PSNC has properly accounted for its gas costs during the review period. Therefore, the gas costs incurred by PSNC during the review period are as set forth in Paton Exhibit 1, and not as recalculated by Public Staff witness Eastwood, and the appropriate balances of the Company's deferred accounts as of March 31, 2011, are a credit balance of $6,545,727 in its Sales Customers Only Deferred Account and a debit balance of $9,411,158 in its All Customers Deferred Account.

Based upon the foregoing, the Commission concludes that the gas costs incurred by PSNC during the test period ended March 31, 2011 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 FINDINGS OF FACT NOS. 10 – 14

The evidence supporting these findings of fact is found in the direct testimony of PSNC witnesses Cronin and Paton and Public Staff witnesses Eastwood, Larsen, and Perry, as well as the Joint Rebuttal Testimony of PSNC witnesses Paton, Cronin, and Jackson (Company rebuttal witnesses).

Company witness Paton testified that the Company accounted for capacity release and other secondary market transactions (SMTs) during the review period in accordance with the Commission's December 22, 1995 Order Approving Stipulation in Docket No. G-100, Sub 67, by recording 75% of the net compensation received from these transactions in the All Customers Deferred Account. Public Staff witness Perry testified that PSNC recorded $10,590,597 of margins on SMTs, including capacity release transactions, asset management arrangements, and other SMTs during the review period, which resulted in a credit of $7,942,947 ($10,590,597 x 75%) to PSNC's All Customers Deferred Account for the benefit of ratepayers. Witness Perry testified that the amount of secondary market transactions reported by the Company was composed of the following items:

Capacity release	$2,158,773
Asset management	5,786,722
Bundled sales	1,365,185
Straddles	1,251,766
Spot sales	28,204
Total	$10,590,597

The Company and the Public Staff agreed on all of the amounts shown in the chart on the previous page, except for the amount of bundled sales.

Public Staff witness Perry noted that bundled sales are sales of delivered gas supply to a third party consisting of gas supply and pipeline capacity at a specified receipt point. She testified that PSNC assigned higher-cost gas to system ratepayers and lower cost gas to certain bundled sales transactions. Witness Perry recommended an adjustment to reassign what she termed "high-priced" gas to secondary market transactions and "low-priced" gas to the system supply that serves ratepayers. In support of her recommendation, witness Perry testified that PSNC purchased 620,869 dekatherms of "high-priced" gas supplies due to commitments it made to bundled sales shippers. Because ratepayers receive 75% of the margins (revenues less cost of gas) on bundled sales, but are assigned 100% of the cost of gas supplies purchased for system requirements, witness Perry concluded that ratepayers may be disadvantaged whenever the gas costs assigned to bundled sales transactions are understated. She proposed an adjustment related to bundled sales transactions that credits PSNC's All Customers Deferred Account for $431,999. Public Staff witness Eastwood computed the applicable interest and determined that the total adjustment, including interest of $6,093, would be $438,092. The Company disagreed with Public Staff witness Perry's adjustment.

It was Public Staff witness Eastwood's view that, based on her review of the gas costs in this proceeding, the appropriate deferred account balance as of March 31, 2011 for the Sales Customer Only Deferred Account (prior to the transfer of the hedging account balance), is a credit balance of $6,545,727. Witness Eastwood also stated that, due to the adjustment recommended by Public Staff witness Perry, the adjusted balance in the All Customers Deferred Account as of March 31, 2011, is a debit balance of $8,973,066. Witness Eastwood further testified that, except for the adjustment related to secondary market transactions as discussed in the testimony of Public Staff witness Perry, PSNC properly accounted for its gas costs during the review period from April 1, 2010, through March 31, 2011.

NATURAL GAS – MISCELLANEOUS

The facts related to the Public Staff's adjustment are largely uncontroverted. Witness Perry testified that, in August 2010, PSNC entered into five-month pre-arranged winter period bundled sales arrangements with two shippers, to deliver 23,000 dts/day of gas supply at PSNC's city gate on a non-recallable basis. Witness Perry added that approximately 78% of these bundled sales volumes were sold to PSNC's gas marketing affiliate and 22% were sold to a non-affiliated shipper. The Company rebuttal witnesses testified that PSNC made subsequent solicitations and, during the third week of October 2010, sold an additional 5,000 dts/day on a non-recallable basis for November 2010 delivery. During the third week of November 2010, PSNC sold an additional 5,000 dts/day on a non-recallable basis for December 2010 delivery. These two additional bundled sales transactions increased PSNC's commitment to 28,000 dts/day for November and December 2010. The Company's commitment for January 2011 through March 2011 remained at 23,000 dts/day. The designation of the bundled sales transactions as non-recallable committed PSNC to provide the gas supplies to the two shippers at the PSNC city gate on a firm basis.

The Company rebuttal witnesses testified that the PSNC system experienced an extended period of colder-than-normal weather beginning in December 2010 that created the need for PSNC to rely more heavily on its interstate storage, thereby limiting future deliverability during the remainder of the winter season. In fact, the Company rebuttal witnesses testified that the Company achieved a record for the month of December 2010 for the most throughput that had gone through the PSNC system in a single month. The witnesses further stated that PSNC hit its second highest throughput month during January 2011. Public Staff witness Larsen testified that while there were extended periods of colder-than-normal weather during the review period, PSNC experienced a peak day send out of 600,285 dekatherms on December 14, 2010, when PSNC recorded 39 heating degree days (HDDs). He further stated that this send-out was well below PSNC's peak day design of 55 HDDs with a projected throughput of 677,000 dekatherms.

The Company rebuttal witnesses also testified that the Company encountered unexpected operational and maintenance issues with its Cary liquefied natural gas (LNG) facility during the review period. The witnesses testified that operational issues arose at the LNG facility and that a code violation was found in November 2010 which caused PSNC to shut down the facility. The witnesses further testified that PSNC was concerned regarding the impact of the Cary LNG operational issues, not only for the 2010-2011 winter season, but also for the 2011-2012 injection and liquefaction seasons. The witnesses stated that they knew repairs were going to have to be made, and they expressed concern that the 2011-2012 liquefaction process would start late, resulting in lower than normal storage levels for the 2011-2012 winter season.

In response to the cold weather and unusually high early-winter storage draws, and problems at the Cary LNG facility, PSNC obtained 620,869 dekatherms of additional gas supplies to meet system needs during the months of December 2010 through February 2011. These gas supplies, referred to by the Company and Public Staff witnesses as "Delivered Deals," were delivered to PSNC's city gate at prices that exceeded the price of monthly index-priced gas supplies that PSNC purchased pursuant to its long-term system gas supply contracts.

Public Staff witness Perry explained that the primary cause of the high prices for the Delivered Deal gas supplies was that these gas supplies were purchased for delivery to the PSNC city gate, and, therefore, included the market value of the capacity costs to transport the gas supply from Transco Zone 3 (typically, within Zone 3 at Transco's Station 65 at the Louisiana-Mississippi border) or Zone 4 (typically, within Zone 4 at Transco Station 85, in Alabama) to the PSNC city gate. In contrast, the system gas supply purchases are made at Transco Zone 3 and Zone 4 and transported to PSNC's city gate using its firm pipeline transportation contracts. These system gas supply purchases result in very minimal variable charges added to the Transco Zone 3 and Zone 4 gas supply price to deliver the gas to the city gate. Witness Perry testified that she considered these Delivered Deal gas supplies as replacing the Transco Zone 4 gas supplies and interstate transportation capacity that PSNC had assigned to bundled sales. Because of the high demand for pipeline transportation service that existed during the days when PSNC purchased these gas supplies, the market value of the transportation to the city gate, though available, was very expensive and resulted in very high delivered prices for the replacement gas. Witness Perry asserted that assigning the high-priced Delivered Deal gas supplies to ratepayers resulted in the ratepayers paying twice for the same interstate pipeline transportation capacity.

Witness Perry testified that PSNC assigned the higher-priced Delivered Deal gas supplies to system requirements, which is included in the cost of gas charged to ratepayers, and assigned the lower-priced monthly index-priced gas supplies to bundled sales transactions. In contrast, witness Perry testified that she assigned the higher-priced Delivered Deal gas supplies to bundled sales transactions and the lower-priced monthly index-priced gas supplies to system requirements. Public Staff witness Perry's adjustment, excluding interest, is computed as the difference in total cost between these two sources of gas supply multiplied by the 25% shareholder sharing percent applicable to secondary market transactions.

Witness Perry testified that secondary market transactions, including bundled sales transactions, entail the release or resale to a third party of an unutilized Local Distribution Company (LDC) asset or resource, such as contracted firm pipeline capacity, storage or gas supply, and that SMTs should be incidental to the LDC's performance of its obligation to provide the "best cost" service to its ratepayers. She testified that "[b]ecause ratepayers pay rates that include the full cost of firm pipeline capacity, storage, and gas supply, the Commission concluded in its December 22, 1995, Order Approving Stipulation in Docket No. G-100, Sub 67, that ratepayers should be entitled to a substantial portion of the revenue (net compensation) from secondary market transactions." The Public Staff argued that, as a regulated public utility, PSNC's first and foremost public service obligation is to serve its firm regulated market. Upon cross examination, Company witness Cronin indicated that the Company does try to fulfill its obligation in accordance with Commission Rule R6-23, which states:

> The production and/or storage capacity of the utility's plant, supplemented by the gas supply regularly available from other sources, must be sufficiently large to meet all reasonably expectable demands for firm service.

Witness Perry concluded that the Company, by assigning the high-priced gas supplies to system requirements, had assigned all of the risk of loss on the transactions to ratepayers and none of the risk of loss to shareholders.

The Company rebuttal witnesses testified that the Public Staff's proposed accounting adjustment is inconsistent with the Commission's long-established accounting policies concerning SMTs and the Stipulation entered into by the Public Staff, gas LDCs, and the Carolina Utility Customers Association (CUCA) and approved by the Commission in Docket No. G-100, Sub 67. The approved Stipulation contained the definition of "secondary market transactions" and set the sharing ratio for the net compensation from these transactions at 75% to ratepayers and 25% to the LDC. The Stipulation also defined the "net compensation" to be shared as "the gross compensation received by an LDC from a secondary market transaction less all transportation charges, taxes and other costs, including all costs incurred by the LDC in connection with the purchase of the gas directly related to the transaction." The Company rebuttal witnesses noted that, in its Order in Docket No. G-100, Sub 67, the Commission stated that "[t]he aggressive utilization of secondary market transactions will provide a means for the LDCs to minimize customer costs."

The Company rebuttal witnesses testified that PSNC accounted for its bundled sales in conformance with the Commission's Order in Docket No. G-100, Sub 67. In particular, PSNC purchased term supply specifically to meet the requirements of the bundled sales, and attributed the cost of those purchases to the bundled sales consistent with the Commission's definition of net compensation, which includes all costs incurred by the LDC in connection with the purchase of the gas directly related to the SMT. On redirect, witness Jackson explained that, at the beginning of the winter, PSNC assigned term supply to the bundled sales by matching up the volumes for the bundled sales with the same two packages of gas every month of the winter season. In response to a question from the Commission, witness Jackson testified that the matching of bundled sales with their supply allows the Company to assign the cost directly related to those secondary market transactions.

The Company rebuttal witnesses argued that the Public Staff adjustment does not align the bundled sales transactions with the costs directly related to those transactions, and that the adjustment is based on hindsight without taking into account what was known at the time the Company made the decision to make bundled sales. They testified that PSNC had already committed to the sales months earlier based on information known at the time, and that this was done in an effort to minimize costs to customers. They noted that PSNC had entered into bundled sales deals successfully in prior years. They also testified that the gas cost accounting process permits the Company to lock-in the margin on bundled sales so that customers do not experience additional risk. The Company rebuttal witnesses concluded that "[t]he Public Staff's retroactive assignment of costs ignores what was reasonably known or should have been known at the time the decision was made."

The Company rebuttal witnesses testified that PSNC has consistently accounted for bundled sales, including during periods when delivered gas was purchased, and that this is the first time the Public Staff has questioned that accounting treatment. In particular, PSNC purchased delivered gas during the last review period, and the Public Staff did not challenge the Company's accounting treatment regarding those purchases. On cross-examination, Public Staff witness Perry stated that PSNC had made bundled sales and had delivered gas purchases during the prior review period and that the Public Staff had not proposed a similar adjustment even though PSNC had made the pertinent information available. The Company rebuttal witnesses testified that PSNC had no reason to believe that the accounting rules would change after it had completed the delivered gas purchases and incurred those costs during this review period.

The Company rebuttal witnesses testified that, in response to the Commission's orders, the Company has aggressively pursued secondary market transactions and has made bundled sales since the winter of 2003-2004. Prior to the winter of 2010-2011 and based on what was known at the time, PSNC determined that it would have sufficient unutilized capacity to make non-recallable bundled sales for the winter season. It later determined that it would have incremental idle capacity to make additional bundled sales for the months of November and December 2010. The prudence of these decisions has not been challenged. In addition, making these sales on a non-recallable basis enabled customers to recognize more value from the transaction than if they were sold on a recallable basis. PSNC witness Jackson estimated the value of the non-recallable sales was roughly seven times greater than for recallable bundled sales.

The Company rebuttal witnesses took issue with Public Staff witness Perry's recommended accounting policy of targeting the lowest cost gas supplies to the firm market. It noted that the Commission had previously determined in Docket No. G-5, Sub 431, that this type of decision should be addressed in a generic proceeding. Additionally, the panel expressed concern that this recommendation represents a significant change to the definition of net compensation which, if adopted, would drastically reduce an LDC's desire to engage in secondary market transactions, contrary to the Commission's policy encouraging their utilization.

On cross-examination, PSNC witness Cronin testified that the Company's design day factors in 55 heating degree-days (which means PSNC plans for a day on which the average of the high and low temperature is 10°F) and that the Company had sufficient assets to fulfill its obligation to meet all reasonably expectable demands for firm services on such a design day.

PSNC witness Jackson explained on redirect examination that the Company contracts for interstate capacity to meet its customers' firm design-day needs. Witness Jackson explained that, because it is impossible to match exactly the amount of capacity with those needs, the Company has capacity above what is needed for the design day, and the Company pursues SMTs for that capacity.

The Company rebuttal witnesses explained in detail why Delivered Deal gas purchases were made during the review period. They noted that PSNC's interstate storage assets and its on-system LNG facility typically would have been available to supply the quantities in lieu of the Delivered Deal gas purchases. However, after the bundled sales were made, these storage assets experienced limitations. An extended period of colder than normal weather beginning in December 2010 created the need for the Company to rely more heavily on interstate storage, thereby limiting future deliverability from these storage assets during the remainder of the winter season. Additionally, the Company encountered unexpected operational issues with its LNG facility, which resulted in a lower-than-planned LNG inventory for the winter of 2010 - 2011, as well as limitations on the ability to refill LNG storage for the 2011 - 2012 winter. Therefore, PSNC decided to use its LNG facility conservatively to ensure its availability for a potential peak day later in the winter. Because of these limitations, the Company made decisions to purchase Delivered Deal gas in order to meet the incremental daily demand on its system and to ensure reliable service to its customers. The Company rebuttal witnesses noted that no party had challenged the prudence of those decisions.

Public Staff witness Perry stated that the Company was unable to serve system supply ratepayers from its owned and contracted gas supply and capacity resources because it had committed them to the bundled sales shippers. Witness Jackson explained on redirect examination that PSNC could have used other assets, such as LNG and interstate storage, rather than delivered gas purchases to meet its firm commitment but decided to conserve those assets since the Company did not know if a peak or design day would occur the following January or February. Witness Jackson testified that, in light of the operational constraints, the purchase of Delivered Deal gas was the best cost alternative for PSNC's customers. On examination by the Commission, witness Jackson added that the Public Staff's proposed adjustment completely disregarded the operational issues surrounding the Company's decision to make delivered purchases in order to meet incremental firm demand, without the benefit of hindsight. Witness Larsen agreed that the Company had resources to serve its firm market (ratepayers) during periods of peak consumption. He testified that the cost of any additional supplies/capacity should not be borne by ratepayers while the Company committed firm assets to the secondary market during the same time period.

After careful consideration, the Commission concludes that PSNC's SMTs, including the bundled sales, were reasonable and prudent. The PSNC witnesses testified in detail regarding the circumstances at the time the transactions were entered into as well as the unexpected circumstances that later arose resulting in the decision to make purchases of the delivered gas supplies. This testimony was not disputed by the Public Staff. Indeed, Public Staff witness Larsen stated in his direct testimony as well as on cross-examination that PSNC's gas costs were prudently incurred.

The Public Staff argued that PSNC's participation in SMTs should be incidental to the LDC's performance of its obligation to provide the "best cost" service to ratepayers and without risk to ratepayers. The Public Staff pointed to G-5, Sub 431 in support of the argument that SMT participation should be incidental. The relevant issue in that docket concerned Transco's FS gas supply service. That service was structured so that PSNC received a credit if it did not use the full amount of gas. PSNC claimed a reduction in takes below the FS demand ceiling credit as an SMT, with 25% retained by the Company. The Public Staff argued convincingly in that docket that, had this gas supply service been structured with tiered costs rather than a ceiling with a credit for taking less, then no SMT with 25% retention for the Company would have been warranted. The Public Staff argued that "if the exercise of the demand ceiling credit provision in question is considered a secondary market transaction, then the LDCs will be provided an incentive to alter contract provisions with pipelines and suppliers with the objective of generating additional secondary market margins, instead of providing the best cost to ratepayers." The Public Staff stated that it would not be in the public interest for contracts to be re-structured in such a manner. The Commission agreed.

A more basic of example of SMT activity being incidental to providing service to ratepayers involves the acquisition of capacity. The Commission has recognized that, as PSNC witness Jackson testified, interstate capacity is not always available in the exact amount required. With that caveat, an LDC should acquire interstate capacity to meet its firm customers' needs and not primarily to enable itself to make more SMTs. For this reason, the examination of the LDC's level of capacity and capacity addition practices is a critical component of an annual review of gas costs.

The Commission concurs with the view that SMT activity should be incidental in the sense that an LDC should not place SMTs ahead of its basic duty to stand ready to meet the needs of its firm customers. However, given that interstate charges are passed through to ratepayers by LDCs, the importance of SMTs in minimizing costs to ratepayers must be considered. The Order in Docket No. G-100, Sub 67 stated, "The Commission's purpose in approving the sharing mechanism for secondary market transactions was to give the LDCs an incentive to participate actively in such transactions so as to minimize the costs borne by their ratepayers."

The Commission notes that SMTs originally grew out of the FERC's decision to revert to a rate design methodology that places all of the fixed costs of interstate companies in the demand charges paid by their customers (such as PSNC). FERC balanced that action with the quid pro quo of allowing those customers to release capacity (in SMTs) when it wasn't needed. Since the federal Filed Rate Doctrine -- and North Carolina law -- allows PSNC to pass its interstate demand charges on to its captive North Carolina ratepayers, as a matter of public policy, this Commission has an interest in seeing to it that as much value as possible is recaptured for the ratepayers through SMTs. This was noted in the Docket No. G-100, Sub 67 Order. So while structuring a deal, adding capacity, or taking other actions primarily just to maximize SMT net margins is inappropriate, maximizing SMT net margins within the Company's best cost policy is not only appropriate, but is a responsibility of a prudently operated LDC. As a regulated monopoly, an LDC has a duty to keep its costs as low as reasonably possible.

It follows, therefore, that once having acquired an appropriate amount of capacity and supply to meet customers' needs, the Company's reasonable efforts to enter into SMTs to minimize the burden on ratepayers should not be considered "incidental." In this docket, the Company's assessment of its needs for the 2010 - 2011 winter were not challenged, nor was its decision to attempt to maximize the value of its SMTs by making them non-recallable explicitly challenged, at least not until after the fact. Moreover, its decision to husband its storage capacity for possible late-winter cold periods was not challenged. Effectively punishing PSNC with an after-the-fact adjustment in accounting methodologies for gas costs would not be consistent with that policy goal of minimizing gas costs through the use of SMTs.

The Public Staff argued that the Commission, in its regulation of North Carolina utilities, has consistently required utilities to directly assign its lowest cost energy supplies to the captive regulated market. In support of this argument, the Public Staff pointed to the decisions in electric industry dockets, specifically two recent proceedings that addressed related issues involving Duke Energy (Duke). In Docket No. E-7, Sub 858, Duke and the City of Orangeburg filed a petition that, if granted, would have allowed Duke to allocate system average costs to the

City of Orangeburg, a non-native load customer, instead of incremental costs. In Docket No. E-7, Sub 751, the Commission approved Duke's sharing mechanism for Net Revenues from Bulk Power Marketing (BPM) and defined BPM Net Revenues as "gross revenues from BPM Sales less incremental costs associated with the BPM Sales, as determined by a post event dispatch model that assigns the lowest cost generation to serve the retail and cost-based wholesale load."

The Commission is not persuaded that the Duke/Orangeburg Order and the Duke BPM Order are applicable to the present situation, as those orders addressed electric ratemaking issues that involved factual situations that are quite different from those involved in PSNC's SMTs. PSNC has argued that assigning high-cost gas supplies to SMTs after the fact would discourage LDCs from entering into SMTs that are intended to maximize the recovery of costs for the benefit of ratepayers.

Moreover, the Commission agrees with PSNC that, in making the purchases of delivered gas in order to meet incremental firm demand, it had no reason to believe that the accounting rules would change after the transactions were completed. Since approving the Stipulation in Docket No. G-100, Sub 67, the Commission has not altered the accounting rules for secondary market transactions and the definition of "net compensation" as including all costs "directly related to the transaction" has remained in effect. The record in this case demonstrates unequivocally that the cost of gas supplies and capacity assigned by PSNC to the bundled sales were directly related to those transactions. Thus, the Commission concludes that 75% of the net compensation associated with the bundled sales, defined as including all directly-related costs, should be credited to the All Customers Deferred Account as proposed by PSNC.

The Commission also agrees with PSNC that the effect of the Public Staff's proposed accounting adjustment would significantly change the definition of "net compensation" set forth in Docket No. G-100, Sub 67, by modifying the costs assigned to the bundled sales secondary market transactions from those directly related to the bundled sales to those related to other delivered gas purchases. And, as pointed out by PSNC, the Commission previously considered another case in which parties unsuccessfully argued that net compensation should be adjusted when secondary market transactions had been entered into and subsequent delivered purchases were made.

The Commission notes that PSNC's secondary market transactions, while beneficial to shareholders, have also provided substantial value to PSNC's customers over the last several years. As the PSNC panel of witnesses testified in rebuttal, from April 2003 through March 2011 secondary market transactions resulted in a total of $56.4 million in credits to customers, of which $6.6 million was directly attributable to bundled sales. The Commission has long recognized this value.

Furthermore, the Commission finds and concludes that PSNC's decision to enter into Delivered Deals when storage assets were still available was reasonable and prudent. PSNC argued that storage assets needed to be held in reserve to protect against cold periods late in the winter season. The Commission concurs. With the Company allowed to retain 25% of the net compensation from SMTs, the Public Staff's accounting adjustment might create an incentive for

PSNC to draw down storage in situations like the one seen in the winter of 2010 - 2011. A period of extreme cold weather late in the heating season might then leave the Company short of capacity and unable to meet the needs of its firm customers. The Commission does not believe it would be appropriate to create an incentive for a company to take such a risk.

Based on the foregoing, the Commission finds and concludes that it is not appropriate to accept the Public Staff's proposed secondary market transaction adjustment in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 15 AND 16

The evidence supporting these findings of fact is found in the direct testimony of PSNC witness Paton and Public Staff witness Eastwood.

Schedule 1 of Paton Exhibit 1, a summary of gas costs expenses for the period under review, reflects demand and storage costs of $71,213,096, commodity costs of $209,967,314, and other gas costs of $199,017 for a total of $281,379,428. PSNC witness Paton testified that the appropriate balances of the Company's deferred accounts as of March 31, 2011, are a credit balance of $6,545,727 in its Sales Customers Only Deferred Account and a debit balance of $9,411,158 in its All Customers Deferred Account.

Public Staff witness Eastwood testified that PSNC properly accounted for its gas costs during the review period, except for an adjustment related to secondary market transactions recommended by Public Staff witness Perry. Based on witness Perry's recommended secondary market adjustment, witness Eastwood recalculated PSNC's total gas costs for the review period ended March 31, 2011, to be $280,947,428, consisting of $69,485,100 of demand and storage charges, $209,967,314 of commodity costs and $1,495,014 of other gas costs. Based upon that same recommendation by witness Perry, witness Eastwood made a secondary market adjustment of ($438,092), including interest, to the All Customers Deferred Account. After this adjustment, the balance in the All Customers Deferred Account as of March 31, 2011, as proposed by the Public Staff, is a debit balance of $8,973,066 owed to the Company. Witness Eastwood agreed that the appropriate deferred account balance as of March 31, 2011, for the Sales Customers Only Deferred Account is a credit balance of $6,545,727 (before the transfer of the hedging balance).

Because the Commission finds that the secondary market transaction adjustment proposed by the Public Staff in this proceeding is not appropriate, the Commission concludes that PSNC has properly accounted for its gas costs during the review period. Therefore, the gas costs incurred by PSNC during the review period are as set forth in Paton Exhibit 1, and not as recalculated by Public Staff witness Eastwood. The appropriate balances of the Company's deferred accounts as of March 31, 2011, are a credit balance of $6,545,727 in its Sales Customers Only Deferred Account and a debit balance of $9,411,158 in its All Customers Deferred Account.

NATURAL GAS – MISCELLANEOUS

EVIDENCE AND CONLUSIONS FOR FINDINGS OF FACT NOS. 17 – 19

The evidence for these findings of fact is contained in the testimony of PSNC witnesses Paton and Cronin and Public Staff witnesses Eastwood and Perry.

PSNC witness Paton testified that during the review period the Company incurred net costs of $5,731,901 in its Hedging Deferred Account. Public Staff witness Perry testified that these costs were composed of: Economic Gains - Closed Positions of ($21,240); Premiums Paid – Closed Positions of $1,839,960; Premiums Paid – Open Positions of $3,153,930; Brokerage Fees and Commissions of $4,562; Interest on the Brokerage Account of $370; and Interest on the Hedging Deferred Account of $754,320.

PSNC witness Cronin testified that the primary objective of PSNC's hedging program has always been to help manage the price volatility of natural gas to PSNC's 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 Cronin stated that PSNC's hedging program currently utilizes call options in order to help control costs while still providing protection from higher prices. Witness Cronin 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 Cronin testified that financial hedges are limited to 25% of PSNC's annually estimated 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 Cronin further testified that no changes were made to PSNC's hedging program during this review period. She also testified that the combination of the increased supply from unconventional shale gas plays coupled with the slowing demand associated with the global recession have resulted in lower gas prices and a reduction in price volatility during the last few years compared to that during prior periods. Witness Cronin additionally testified that shifts in production, changes in demand, impacts from weather, and changes in the environmental or other regulatory policies will have an impact on natural gas prices; and, therefore, PSNC continues to believe that its conservative approach to hedging is a reasonable and prudent way to provide a measure of protection to customers. She went on to state that PSNC will continue to analyze and evaluate its hedging program and implement changes to that program as warranted.

Witness Cronin stated that, in PSNC's last Annual Review of Gas Costs, in Docket No. G-5, Sub 516, the Commission directed PSNC to address the information, other than the models, that it uses in its hedging program and how it has or will deviate from the guidance provided in its models. In response to this Commission directive, Company witness Cronin elaborated that although the hedging models incorporate both future price projections and historical data, PSNC also uses third-party information about developments in the natural gas market and projected price movements to make informed decisions under the hedging models. Among the information considered are reports on the natural gas industry issued by Cambridge Energy Research Associates, the Energy Information Administration, and Kase and Company as well as analyses provided by market participants such as Citigroup, Wells Fargo, Credit Suisse, and JP Morgan, among others. Market factors used by these companies in performing their assessments include national storage levels, production and demand estimates, alternative fuel choices, new industry trends, weather forecasts, and pending regulation.

Witness Cronin testified that, while deviations from the hedging models are rare, one such occurrence arose when the Company initially hedged under the program in 2003. At that time, prices were already above where the model would have recommended placing hedges. However, based on weather forecasts and dwindling national storage levels, the Company determined that some protection against the possibility of upward price movement was warranted and a decision was made to place some hedges for the winter period. Prices did rise that winter and, because these hedges were in place, hedging gains were realized to offset a portion of the increase in prices. She further testified that the Company opted to take action outside of the hedging models a second time when positions were restructured in the spring of 2008. In March of that year natural gas prices unexpectedly crossed the $10 per dekatherm mark despite increased drilling activity and above-average storage levels. As a result of the rise in prices, the in-place positions triggered by the models prior to the increase revealed projected hedging gains for many months into the future. Due to difficulty in reconciling the high price levels being seen in the market with some of the fundamental analysis being issued by various outlets, the Company began looking into ways to capture some of the projected gain in existing hedge positions. One of the models followed by the Company allows for discretion when prices are at historically high levels and positions are in place with accumulated gains. By exercising this discretion, the Company established parameters under which all positions would be restructured under both models. This restructuring enabled the Company to maintain some price protection while capturing some of the gains that had been accumulated in the positions, in addition to allowing for the downside participation if prices fell.

Witness Cronin stated that it is impossible to tell if future circumstances will dictate a deviation from the models. She went on to say that the Company will continue to monitor the market information, compare it to the models' outputs, and deviate from the models when it is in the customers' best interest.

Public Staff witness Perry testified that the Public Staff's review of the Company's hedging activities is an ongoing multidisciplinary team effort and includes the following: analysis and evaluation of the Company's monthly hedging deferred account reports, detailed source documentation, workpapers supporting maximum targeted hedge volumes, periodic reports on the status of hedge coverage, periodic reports on the market values of the various financial instruments used by the Company, monthly Hedging Program Status Reports, monthly reports reconciling the Hedging Program Status Report and the hedging deferred account report, minutes from SCANA Risk Management Committee meetings and SCANA Board of Directors meetings, reports and correspondence from the Company's internal and external auditors, hedging plan documents, communications with Company personnel regarding key hedging events, and the Company witnesses' testimonies and exhibits in this proceeding. Witness Perry further testified that in the Commission's February 26, 2002, Order on Hedging in Docket No. G-100, Sub 84, the Commission stated that the standard for reviewing the prudence of hedging decisions is that the decision "must have been made in a reasonable manner and at an appropriate time on the basis of what was reasonably known or should have been known at that time." Witness Perry testified that the hedging costs incurred by the company during the review period represented approximately 2% of its gas supply costs or $0.13 per dekatherm. Witness Perry concluded that PSNC's hedging activities were reasonable and prudent and that the ending net debit balance of $5,731,901 should be transferred to the Sales Customer Only Deferred Account.

Public Staff witness Eastwood testified that, based on the recommendation of Public Staff witness Perry, she transferred the $5,731,901 debit balance in the Hedging Deferred Account, as of the end of the review period, to the Company's Sales Customer Only Deferred Account. Witness Eastwood further stated that the recommended balance for the Sales Customer Only Deferred Account as of March 31, 2011, is a credit balance, owed to the Customers, of $813,826.

The Commission agrees with the Public Staff that PSNC's hedging activities during the review period were reasonable and prudent and that its hedging net debit balance of $5,731,901 incurred during the review period should be transferred to the Company's Sales Customers Only Deferred Account, resulting in a Sales Customers Only Deferred Account net credit balance of $813,826 as of March 31, 2011.

The Commission further concludes that the Company properly addressed the Commission's request for the information, other than the models, that it uses in its hedging program and how it has or will deviate from the guidance provided by the models.

EVIDENCE AND CONLUSIONS FOR FINDINGS OF FACT NO. 20

The evidence for these findings of fact is found in the testimony of PSNC witness Paton and Public Staff witness Larsen.

Company witness Paton testified that the Company was proposing a new a temporary decrement the Sales Customers Only Deferred Account and temporary increments applicable to the All Customers Deferred Account. Public Staff witness Larsen testified that the Public Staff agrees with PSNC's calculated decrement applicable to the Sales Customers Only Deferred Account contained in Company witness Paton's testimony and exhibits but that he calculated new increments applicable to the All Customers Deferred Account based on the adjusted balance recommended by Public Staff witness Eastwood. Witness Larsen also testified that he recommended removing the existing temporaries that were implemented in PSNC's last Annual Review of Gas Costs proceeding and applying the temporaries recommended by him in the instant docket.

The Commission examined Public Staff witness Larsen as to what effect the recommended temporary increments would have on a typical residential customer's bill. Witness Larsen responded that there would be an annual reduction of about $1.86 in residential customers' bills. The Commission asked witness Larsen about the effect on other customer classes and witness Larsen responded that he would provide the Commission with a late-filed exhibit that would provide details of the effect of the proposed rate changes on other customer classes. This exhibit, filed on August 16, 2011 and labeled Public Staff Late-Filed Exhibit No. 1, shows the effect on small general service customers' bills to be an annual decrease of $27.92.

Because the Commission found that it was not appropriate to accept Public Staff witnesses Perry's adjustment to the All Customers Deferred Account, it would also not be appropriate to use witness Larsen's temporary rate increments calculated using witness Eastwood's adjusted balance. Therefore, the Commission concludes that PSNC witness Paton's temporary increments applicable to the All Customers Deferred Account should be implemented in this docket.

Based upon the foregoing, the Commission concludes that it is appropriate for PSNC to remove all temporary rate increments and decrements implemented in Docket No. G-5, Sub 516, and implement the temporary decrement to the Sales Customers Only Deferred Account as proposed by Company witness Paton and concurred by Public Staff witness Larsen, and implement the increments to the Company's All Customers Deferred Account recommended by PSNC witness Paton.

EVIDENCE AND CONLUSIONS FOR FINDING OF FACT NO. 21

The evidence for these findings of fact is found in the testimony of PSNC witness Paton and Public Staff witness Larsen.

Company witness Paton testified that she proposed an increase to the fixed gas cost collection component of rates. She stated that the current fixed gas cost recovery rates were determined in the Company's last general rate case, Docket No. G-5, Sub 495, and have been in effect since November 1, 2008. Since that time the Company has added both transportation and storage services and experienced changes in rates charged by its pipeline suppliers for transportation and storage. She also stated that the result is an increase in annual fixed gas costs of $7,081,103, and therefore, PSNC proposed to increase the fixed gas cost component of its rates.

Public Staff witness Larsen testified that he agreed with Company witness Paton's proposed increase in fixed gas cost collection rates. In reaching this conclusion, witness Larsen testified that in Docket No. G-5, Sub 467, which was PSNC's 2005 Annual Review of Gas Costs proceeding, PSNC requested, and the Commission approved, a change in PSNC's fixed gas cost collection rates. This was in addition to the change in temporary increments and decrements that are usually changed in an annual review proceeding. Witness Larsen further testified that in the course of its investigation, the Public Staff learned that PSNC had under-collected its fixed gas costs in the majority of the months since its last general rate case, when rates were implemented in November 2008. Witness Larsen also noted that there has been approximately 5% growth in the number of customers since the last general rate case, so an increase in fixed gas costs in order to provide the appropriate storage and demand services to customers can be expected.

The Commission concludes that the fixed gas cost collection rates, as recommended by Company witness Paton and agreed to by Public Staff witness Larsen, should be implemented and that the existing fixed gas cost collection rates, established in G-5, Sub 495 should be subsequently removed.

EVIDENCE AND CONLUSIONS FOR FINDING OF FACT NO. 22

The evidence supporting this finding of fact is found in the cross-examination of Public Staff witness Perry.

Public Staff witness Perry referred to two agreements between PSNC and bundled sales-related shippers to buy or sell natural gas. Witness Perry stated that the affiliated contract may need to be filed with the Commission for approval. Based on PSNC's Code of Conduct, Section II.E.5,[1] it is appropriate for PSNC to file with the Commission for approval, the Base Contract For the Sale and Purchase of Natural Gas dated April 1, 2005, between PSNC and SCANA Energy Marketing, Inc., a gas marketing affiliate.

The Commission finds that based on PSNC's Code of Conduct, Section II.E.5, PSNC shall file with the Commission for approval, the Base Contract For the Sale and Purchase of Natural Gas dated April 1, 2005, between PSNC and SCANA Energy Marketing, Inc., a gas marketing affiliate.

IT IS, THEREFORE, ORDERED as follows:

1. That PSNC's accounting for gas costs for the twelve-month period ended March 31, 2011, is approved;

2. That the gas costs incurred by PSNC during the twelve-month period ended March 31, 2011, were reasonably and prudently incurred, and PSNC is hereby authorized to recover 100% of these gas costs as provided herein;

3. Pursuant to PSNC's Code of Conduct, Section II.E.5, PSNC shall file the Base Contract For the Sale and Purchase of Natural Gas dated April 1, 2005, between PSNC and SCANA Energy Marketing, Inc., a gas marketing affiliate, with the Commission for approval;

4. That PSNC shall remove the existing temporary rate adjustments that were implemented in PSNC's last Annual Review of Gas Costs proceeding and implement the temporary rate increments and decrement recommended by PSNC witness Patton in the instant docket, effective for service rendered on and after December 1, 2011;

5. That PSNC shall remove the existing fixed gas cost collection rates implemented in PSNC's last general rate case, Docket No. G-5, Sub 495, and implement the new fixed gas

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[1] Section II.E.5 provides: All gas supply and/or transportation arrangements between the NC Jurisdictional Operations and the affiliates, and/or the NC Nonjurisdictional Operations of more than three months shall be filed with the NCUC in advance, provided that the Public Staff is advised of transactions of shorter durations by facsimile or other means of immediate communications.

cost collection rates as proposed by Company witness Paton and concurred by Public Staff witness Larsen, effective for service rendered on and after January 1, 2012;

6. That PSNC shall give notice to its customers of the rate changes allowed in this Order.

ISSUED BY ORDER OF THE COMMISSION
This the _5th_ day of December, 2011.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

kh120511.03

DOCKET NO. G-5, SUB 524

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)	)))))	ERRATA ORDER

BY THE COMMISSION: On December 5, 2011, the Commission issued its Order on Annual Review of Gas Costs in the above-captioned docket. Ordering Paragraph Four of that Order referenced December 1, 2011, however, the correct date to be referenced is January 1, 2012.

The Commission, therefore, finds good cause to issue this errata order to correct Ordering Paragraph Four to read as follows:

> 4. That PSNC shall remove the existing temporary rate adjustments that were implemented in PSNC's last Annual Review of Gas Costs proceeding and implement the temporary rate increments and decrement recommended by PSNC witness Paton in the instant docket, effective for service rendered on and after January 1, 2012.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION
This the _7th_ day of December, 2011.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

kh120711.01

DOCKET NO. RET-11, SUB 0
DOCKET NO. RET-12, SUB 0
DOCKET NO. RET-13, SUB 0
DOCKET NO. RET-14, SUB 0
DOCKET NO. RET-15, SUB 0
DOCKET NO. RET-16, SUB 0
DOCKET NO. RET-17, SUB 0
DOCKET NO. RET-18, SUB 0
DOCKET NO. RET-19, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. RET-11, SUB 0 In the Matter of Application of Camp Rockmont for Boys for Registration of a New Renewable Energy Facility DOCKET NO. RET-12, SUB 0 In the Matter of Application of Guilford College for Registration of a New Renewable Energy Facility DOCKET NO. RET-13, SUB 0 In the Matter of Application of Green Sage Coffeehouse and Café for Registration of a New Renewable Energy Facility DOCKET NO. RET-14, SUB 0 In the Matter of Application of The Market Place Restaurant for Registration of a New Renewable Energy Facility DOCKET NO. RET-15, SUB 0 In the Matter of Application of Pisgah Inn for Registration of a New Renewable Energy Facility	ORDER ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITIES AND RULING ON REQUESTS FOR WAIVERS

RENEWABLE ENERGY THERMAL – FILINGS DUE PER ORDER OR RULE

DOCKET NO. RET-16, SUB 0	)
In the Matter of Application of Kanuga Conferences, Inc., for Registration of a New Renewable Energy Facility	)
DOCKET NO. RET-17, SUB 0	)
In the Matter of Application of Biowheels for Registration of a New Renewable Energy Facility	)
DOCKET NO. RET-18, SUB 0	)
In the Matter of Application of West End Bakery for Registration of a New Renewable Energy Facility	)
DOCKET NO. RET-19, SUB 0	)
In the Matter of Application of Mighty Good Eats, LLC, for Registration of a New Renewable Energy Facility	)

BY THE CHAIRMAN: From February 8, 2010, through June 21, 2010, FLS Energy, Inc., and FLS YK Farm, LLC (collectively, FLS), filed registration statements pursuant to Commission Rule R8-66 in the above-captioned dockets on behalf of Camp Rockmont for Boys, Guilford College, Green Sage Coffeehouse and Café, The Market Place Restaurant, Pisgah Inn, Kanuga Conferences, Inc., Biowheels, West End Bakery and Mighty Good Eats, LLC (Applicants), for new solar thermal renewable energy facilities located in North Carolina. Each registration statement designated FLS as the aggregator of renewable energy certificates (RECs) and stated that all RECs produced at the facilities would be sold to Duke Energy Carolinas, LLC (Duke). In addition, the registration statements stated that it was economically impractical to install monitoring systems at these small facilities. Thus, FLS proposed the use of RETScreen Analysis Software (RETScreen) to calculate the estimated solar thermal production of each facility.

On March 9, 2010, the Public Staff filed the recommendation required by Commission Rule R8-66(e) for each of the above-captioned registration statements, except in Docket Nos. RET-18, Sub 0 and RET-19 Sub 0, in which the Public Staff filed recommendation letters on a later date. In its March 9, 2010 letters, the Public Staff recommended that the registrations be considered incomplete, noting the following concerns: (1) that there was not adequate documentation for the Applicants' claim that metering of these facilities was economically impracticable, and (2) the need to document each facility owner's transfer of RECs to FLS in order for FLS to sell the RECs to Duke.

On March 26, 2010, FLS filed its response to the Public Staff's recommendation. FLS stated, among other things, that it would be economically impracticable to monitor a system generating less than 45,000 kWh or BTU equivalent per year because the resulting payback period for the equipment would exceed the period of depreciation. Additionally, FLS stated that the use of the RETScreen modeling software meets or exceeds industry-accepted methods for estimating solar thermal production. Further, FLS stated that the RETScreen modeling software was the industry's leading modeling software.

On August 4, 2010, the Public Staff filed a letter acknowledging the information filed by FLS on March 26, 2010, and recommending that the registration statements be considered complete and the facilities be considered new renewable energy facilities. However, the Public Staff recommended that these unmetered solar thermal facilities be allowed to earn RECs only for the general renewable energy requirement established pursuant to G.S. 62-133.8(b) and (c), not for the solar set-aside requirement under G.S. 62-133.8(d).

On December 8, 2010, FLS filed a letter requesting that, "up through December 3, 2010," the Commission allow modeled unmetered small solar thermal facilities to earn RECs to be used toward the solar set-aside requirement. Among other things, FLS quoted a portion of Commission Rule R8-67(g)(4) and stated that FLS's prior understanding was that RECs earned at unmetered small solar thermal facilities can count toward the solar set-aside. In addition, FLS stated that, based on its prior understanding and other factors discussed in its March 26, 2010 filing, FLS did not install meters at these facilities, but instead utilized RETScreen, which FLS considers an industry-accepted means to calculate solar thermal energy production. FLS further stated: "FLS Energy is very supportive of recent indications from the NCUC that all solar thermal systems should be monitored to count for the solar set aside. However, this would be a change of policy." Finally, FLS stated that it would install metering for all of its commercial solar thermal facilities, both large and small, in the future.

On January 6, 2011, the Public Staff filed a reply to FLS's December 8, 2010 letter. After reciting the main points in FLS's letter, the Public Staff asserted that the issues raised by FLS were previously addressed in the Commission's July 21, 2010 Order in Docket No. RET-10, Sub 0. Citing the language in G.S. 62-133.8(d) that the solar set-aside requirement must be met through "a combination of new solar electric facilities and new metered solar thermal energy facilities" and the Commission's Order in Docket No. RET-10, Sub 0, the Public Staff stated that RECs produced at an unmetered solar thermal facility qualify for the general renewable energy requirement in G.S. 62-133.8(b) and (c), but not for the solar set-aside requirement in G.S. 62-133.8(d). In addition, the Public Staff stated that it was unaware of any valid basis upon which the Commission could waive the statutory requirement. Thus, the Public Staff recommended that the RECs earned by FLS prior to the installation of meters at these facilities be eligible for meeting the general requirement of G.S. 62-133.8(b) and (c), but not for meeting the solar set-aside requirement.

On March 16, 2011, FLS notified the Commission that the metering of these facilities has been completed.

On August 26, 2011, the Public Staff filed the recommendation required by Commission Rule R8-66(e) in Docket Nos. RET-18, Sub 0 and RET-19 Sub 0 recommending that the registration statements be considered complete and the facilities be considered new renewable energy facilities.

In each of these dockets, FLS and the Applicants filed certified attestations that: 1) the facilities are in substantial compliance with all federal and state laws, regulations, and rules for the protection of the environment and conservation of natural resources; 2) the facilities will be operated as new renewable energy facilities; 3) FLS will not remarket or otherwise resell any RECs sold to an electric power supplier to comply with G.S. 62-133.8; and 4) FLS will consent to the auditing of its books and records by the Public Staff insofar as those records relate to transactions with North Carolina electric power suppliers.

No other party made a filing in these dockets.

Based upon the foregoing and the entire record in these proceedings, the Chairman finds good cause to accept registration of the metered solar thermal facilities as new renewable energy facilities. FLS shall annually file on behalf of the Applicants the information required by Commission Rule R8-66 on or before April 1 of each year. FLS will be required to participate in the NC-RETS REC tracking system (http://www.ncrets.org) in order to facilitate the issuance of RECs.

However, after careful consideration of the filings in these dockets, as well as the applicable statutes, Commission rules and precedent, the Chairman is of the opinion that good cause does not exist to grant FLS's request for a waiver of the requirement in G.S. 62-133.8(d) that solar thermal energy be measured by a meter in order to produce RECs that are eligible to meet the solar set-aside requirement under that statute. The requirement that solar thermal energy be measured by a meter is not new, but was included in the statute when G.S. 62-133.8 was enacted in 2007. Further, FLS has not cited, and the Chairman has not found, any legal authority by which the Commission is authorized to grant a waiver of this requirement.

In addition, the Chairman is of the opinion that FLS's use of RETScreen as the means to determine the RECs earned for the unmetered solar thermal energy produced by these facilities is not appropriate. The RETScreen model will likely overestimate the number of RECs earned because it estimates the total amount of solar thermal energy that could be produced by the panels, not the amount of energy actually used to heat water. Rather, the meter data now being read should be used as a more accurate approximation of the actual usage during the same month in prior years. Thus, the Commission will allow FLS to estimate usage and earn RECs for a facility for months prior to the installation of the meter equal to the usage and RECs earned during the same calendar month initially following installation of the meter for that facility.[1] As stated above, however, only the RECs earned after the installation of the meter are eligible to meet the solar set-aside requirement of G.S. 62-133.8(d); the RECs earned prior to installation of the meter may be used only to meet the general renewable energy requirement established pursuant to G.S. 62-133.8(b) and (c).

[1] For example, if a facility was placed into service in August 2008 and its meter was installed in December 2010, FLS should use the meter reading in January 2011 to estimate the usage in January 2009 and January 2010, the meter reading in February 2011 to estimate the usage in February 2009 and February 2010, and so forth through December 2011 to estimate all historic solar thermal energy usage.

Finally, the Chairman notes that all of these facilities, except those in Docket Nos. RET-18, Sub 0 and RET-19 Sub 0, began operation in 2008. Based on the Commission's December 10, 2010 Order in Docket No. E-100, Sub 113, RECs for historic renewable energy production are allowed to be earned only for renewable energy production up to two years prior to the date it is reported. However, the Commission has endeavored to ensure that all facilities have an adequate opportunity to register with the Commission and with NC-RETS and to have their historic renewable energy production receive appropriate RECs. Therefore, because FLS initially filed its registration statements for these facilities in 2010, prior to the deadline for reporting all historic renewable energy production, the Chairman is of the opinion that good cause exists to grant FLS a waiver of the two-year limitation and to allow FLS to earn RECs based on the solar thermal energy production of these facilities from the date of operation of each of these facilities.

IT IS, THEREFORE, ORDERED as follows:

1. That the registrations of the metered solar thermal facilities in the above-captioned dockets as new renewable energy facilities shall be, and are hereby, accepted.

2. That FLS shall annually file on behalf of the Applicants the information required by Commission Rule R8-66 on or before April 1 of each year for each of these facilities.

3. That FLS's request for a waiver of the requirement in G.S. 62-133.8(d) that solar thermal energy be measured by a meter in order to earn RECs that are eligible to meet the solar set-aside requirement under that statute shall be, and is hereby, denied.

4. That FLS's request to use RETScreen for the measurement of unmetered solar thermal energy produced by these facilities shall be, and is hereby, denied.

5. That FLS shall be allowed to earn RECs eligible to meet the requirements of G.S. 62-133.8(b) and (c) for months prior to the installation of a facility's meter equal to the number of RECs earned during the same calendar month initially following installation of the meter for that facility.

6. That FLS shall be, and is hereby, granted a waiver of the two-year limitation on earning RECs for historic renewable energy production. FLS shall be entitled to receive RECs for all appropriately documented solar thermal energy produced at these facilities since their initial dates of operation.

ISSUED BY ORDER OF THE COMMISSION.
This the 21st day of October, 2011.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Bh102011.01

DOCKET NO. RET-28, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Snowflake Holdings, Inc., for Registration of a New Renewable Energy Facility	) ORDER DENYING REGISTRATION) OF NEW RENEWABLE ENERGY) FACILITY

BY THE COMMISSION: On September 26, 2011, as amended November 21, 2011, Snowflake Holdings, Inc. (Snowflake), filed a registration statement pursuant to Commission Rule R8-66 for a new renewable energy facility to be located in Snowflake, Arizona. Snowflake's registration statement described its facility as a concentrated solar power (CSP) thermal system, consisting of 3,120 parabolic troughs serving as a pre-heat augmentation system for boiler feed water. Snowflake stated that the CSP thermal system would be integrated into an existing 27-MW_{AC} biomass facility which is currently utilizing wood chips and wood sludge as its fuel source for electric generation. Snowflake further stated that the thermal output of the CSP system would be metered and that the system is expected to become operational on or around fourth quarter 2012.

The filing included certified attestations that: 1) the facility will be in substantial compliance with all federal and state laws, regulations, and rules for the protection of the environment and conservation of natural resources; 2) the facility will be operated as a new renewable energy facility; 3) Snowflake will not remarket or otherwise resell any renewable energy certificates (RECs) sold to an electric power supplier to comply with G.S. 62-133.8; and 4) Snowflake will consent to the auditing of its books and records by the Public Staff insofar as those records relate to transactions with North Carolina electric power suppliers.

On November 22, 2011, the Public Staff filed the recommendation required by Commission Rule R8-66(e) stating that Snowflake's registration statement as a new renewable energy facility should be considered to be complete. No other party made a filing with respect to these issues.

After careful consideration, the Commission finds good cause to deny the registration of Snowflake's metered CSP thermal system as a new renewable energy facility. Specifically, Commission Rule R8-67(g)(4) states, in part: "Thermal energy produced by a combined heat and power system or solar thermal energy facility shall be the thermal energy recovered and used for useful purposes other than electric power production." Based upon the integration of the proposed CSP thermal system into the existing biomass facility, the thermal energy generated from the proposed CSP thermal system will be used to generate electricity. By using the energy from the CSP thermal system to pre-heat the feed water entering the biomass-fueled boiler, less biomass fuel will be needed to generate electricity at the existing facility. The Commission, therefore, concludes that the proposed CSP thermal system should not be registered separately from the existing biomass generating facility and allowed to earn RECs for the solar thermal output, but rather must be considered as an alternative fuel source for the electric generating facility, which would be considered for registration in the same manner as any other multi-fuel facility.

IT IS, THEREFORE, SO ORDERED:

ISSUED BY ORDER OF THE COMMISSION.
This the 22nd day of December, 2011.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Commissioner's William T. Culpepper, III, and Susan W. Rabon, did not participate in this decision.

k2122111.06

SMALL POWER PRODUCER – MISCELLANEOUS

DOCKET NO. SP-411, SUB 1

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of International Paper Company for Waiver of Commission Rule R8-67(g)(1)	)) ORDER CLOSING DOCKET)

BY THE CHAIRMAN: In 2009, International Paper Company (IP) filed a registration statement pursuant to Commission Rule R8-66 for a renewable energy facility located at its Riegelwood Mill in Pender County, North Carolina. IP stated that electricity is produced at its three-unit, 60 MW facility by burning spent pulping liquor, wood waste and fossil fuels; that two-thirds of the facility's generation comes from renewable biomass materials; and that steam is extracted from the turbines after electrical power generation to provide process heat in paper manufacturing. On June 15, 2009, the Commission issued an Order accepting registration of IP's facility as a renewable energy facility.

On December 6, 2010, IP filed a letter requesting a waiver of Commission Rule R8-67(g)(1). At the time of IP's request, Rule R8-67(g) provided, in relevant part, as follows:

> (g) Metering of renewable energy facilities.
>
> (1) Except as provided below, for the purpose of receiving renewable energy certificates, the electric power generated by a renewable energy facility shall be measured by an electric meter supplied by and read by an electric power supplier.
>
> ...
>
> (3) The electric power generated by a renewable energy facility with a nameplate capacity of 1 MW or less interconnected behind the utility meter at a customer's location may be measured accurately by an ANSI-certified electric meter not provided by an electric power supplier. The data provided by this meter may be read and self-reported by the owner of the renewable energy facility. The owner of the meter shall comply with the meter testing requirements of Rule R8-13.

In its request, IP stated that the output of its generators is measured by an Allen-Bradley Power Monitor 3000, an industry-accepted, auditable and accurate metering, controls and verification system. IP requested a waiver of the metering requirements of Rule R8-67(g) to allow IP to self-report its generation to the North Carolina REC Tracking System, NC-RETS. IP noted that the Commission had proposed modifications to Rule R8-67(g) that would allow IP to satisfy the metering requirements, but that the waiver was necessary in order to timely report meter data for all generation back to January 1, 2008.

On December 10, 2010, the Commission issued an Order extending until June 1, 2011, the deadline by which all historic energy production data for REC issuance must be provided to NC-RETS. On January 31, 2011, the Commission issued an Order amending Rules R8-64 through R8-69, including the metering requirements for renewable energy facilities in Rule R8-67(g), which, as amended, provides, in relevant part, as follows:

(g) Metering of renewable energy facilities.

(1) Except as provided below, for the purpose of receiving renewable energy certificate issuance in NC-RETS, the electric power generated by a renewable energy facility shall be measured by an electric meter supplied by and read by an electric power supplier. Facilities whose renewable energy certificates are issued in a tracking system other than NC-RETS shall be subject to the requirements of the applicable state commission and/or tracking system.

...

(3) The electric power generated by a renewable energy facility interconnected on the customer's side of the utility meter at a customer's location may be measured by (1) an ANSI-certified electric meter not provided by an electric power supplier provided that the owner of the meter complies with the meter testing requirements of Rule R8-13, or (2) another industry-accepted, auditable and accurate metering, controls, and verification system. The data provided by such meter or system may be read and self-reported by the owner of the renewable energy facility, subject to audit by the Public Staff. The owner of the meter shall retain for audit for 10 years the energy output data.

Based upon the foregoing, the Chairman concludes that IP's request for a waiver is now moot because the amended Rule removes the 1 MW limit on self-reporting customer-owned generation interconnected behind the utility's meter, and, therefore, finds good cause to close this docket.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 4th day of March, 2011.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Sw030411.01

DOCKET NO. SP-1022, SUB 1

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Petition of EnergyUnited Electric Membership	)	ORDER GRANTING
Corporation for Transfer of Renewable Energy	)	REQUEST TO TRANSFER
Certificates from Sun Edison SD, LLC	)	RENEWABLE ENERGY
	)	CERTIFICATES

BY THE CHAIRMAN: On April 28, 2011, EnergyUnited Electric Membership Corporation (EnergyUnited) filed a petition requesting that the Commission allow the transfer of 120 renewable energy certificates (RECs) into the North Carolina Renewable Energy Tracking System (NC-RETS) that have previously been retired in the WREGIS REC tracking system. EnergyUnited stated that the RECs in question are associated with electricity produced by the Alvarado Water Treatment Facility Solar Plant, a 945-kW solar photovoltaic (PV) facility located in San Diego, California, owned by Sun Edison SD, LLC (Sun Edison), and registered with the Commission as a new renewable energy facility. EnergyUnited's petition included attestations documenting that it purchased 120 RECs numbered 713-CA-22068-1 through 713-CA-22068-120 in the WREGIS system. EnergyUnited further stated that the April 2010 RECs "were not retired for any other organization's REPS compliance in any other state" and that they were retired in its name "solely for the purpose of transfer to North Carolina."

On June 13, 2011, the Public Staff filed a letter stating that it had completed its review of the request by EnergyUnited: "As a result of our review, we recommend that [EnergyUnited's] petition be granted."

The Commission approved a similar request by EnergyUnited on March 25, 2011, in Docket No. EMP-17, Sub 1. In that case, EnergyUnited sought approval to transfer into NC-RETS 150,000 RECs that had been retired in the ERCOT REC tracking system in June 2009 associated with electricity produced by a 550-MW wind facility located in Texas. In approving the transfer in that case, the Chairman noted that the subject RECs were issued and retired prior to the development of NC-RETS. The Chairman further noted that the Commission has now established a procedure for transferring RECs into NC-RETS from ERCOT, as well as a number of other REC tracking systems, to ensure that such RECs are legitimate and that a credible audit trail links every REC back to its associated renewable energy output, and stated that this procedure should be followed in the future to avoid the necessity of additional requests for the transfer of previously retired RECs. In the instant matter, according to the attestation attached to the request, the RECs were not purchased by EnergyUnited and retired in WREGIS until August 2010 – after NC-RETS became operational.

After careful consideration, the Chairman finds good cause to allow EnergyUnited's request. The Chairman reiterates, however, that, in the future, EnergyUnited should adhere to the procedure established for transferring RECs from another REC tracking system into NC-RETS and refrain from having such RECs retired in the issuing tracking system prior to transfer.

IT IS, THEREFORE, ORDERED that the request by EnergyUnited to transfer into NC-RETS from the WREGIS REC tracking system 120 RECs (issued as serial numbers 713-CA-

22068-1 through 713-CA-22068-120) that it purchased from Sun Edison and that were retired on its behalf in the WREGIS system be, and the same is hereby, granted.

ISSUED BY ORDER OF THE COMMISSION.
This the 15th day of June, 2011.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Bh061411.01

DOCKET NO. P-61, SUB 102

In the Matter of Petition of Randolph Telephone Company For Authority To Discontinue Provision of Service And Notice of Plan of Dissolution	) ORDER AUTHORIZING DISCONTINUANCE OF SERVICE AND TRANSFER OF ASSETS OF RANDOLPH TELEPHONE COMPANY

BY THE COMMISSION: On September 2, 2011, Randolph Telephone Company (Randolph), through counsel and pursuant to G.S. 62-118 and Commission Rules R21-1, *et seq.*, filed a Petition for Authority to Discontinue Provision of Service (the Petition). By its Petition Randolph requested authorization from the Commission allowing Randolph to discontinue its provision of service to the public, in connection with the dissolution of Randolph and the transfer to Randolph's corporate parent, Randolph Telephone Membership Corporation (RTMC), of all of Randolph's assets. Coincident with such discontinuance of service as the incumbent local exchange carrier (ILEC) in the Liberty exchange, Randolph will dissolve as provided for by law, and transfer to RTMC: (1) all assets within the Liberty, North Carolina exchange currently owned and operated by Randolph, and (2) the right and obligation of Randolph to serve its existing customers within the Liberty exchange. Randolph also requested that the Commission grant any additional authority necessary to accomplish the dissolution and transfer described in the Petition.

On September 12, 2011, the Commission issued its Order Requiring Customer Notice. That Order set a public hearing for October 13, 2011 in Liberty, North Carolina, but provided that this matter could be determined without evidentiary hearing if no significant protests were received subsequent to customer notice. The Commission also required that any party wishing to intervene in this docket file a petition to intervene no later than September 30, 2011.

On September 23, 2011, Randolph filed its Certificate of Service with the Commission certifying that the Commission's required Notice to Customers was mailed on September 16, 2011, within the time required by the Order Requiring Customer Notice. On September 30, 2011, Randolph filed an Affidavit of Publication, reflecting that the required Notice to Customers was published in a newspaper of general circulation in the Liberty exchange on September 18, 2011 and again on September 25, 2011.

No person or entity petitioned to intervene in this docket. The only response to the Notice to Customers was a letter complaining about the price of Randolph's digital subscriber line (DSL) service and a request that the Commission "require RTC to provide cost-effective DSLservice without the additional cost of the land line . . . [and] that the cost of DSL be reduced to be in line with other carriers." DSL service is a broadband service which, by law, the Commission does not regulate; and neither the availability nor the pricing of that service are subject to the Commission's jurisdiction.

On October 3, 2011, Randolph filed a Motion to Cancel Hearing, and on October 6, 2011, the Commission issued its Order Canceling Hearing.

On the basis of the Petition and other matters of record in this docket, the Commission makes the following:

FINDINGS OF FACT

1. Randolph is a North Carolina corporation, authorized to do business in the State of North Carolina as a public utility.

2. RTMC is a not-for profit North Carolina telephone membership corporation (TMC) authorized to do business in the State of North Carolina.

3. In 1994 the Commission approved the sale of Randolph's capital stock to RTMC. Since then, Randolph has been operated as a wholly-owned subsidiary of RTMC.

4. Randolph is an ILEC as defined in Section 251(h) of the Communications Act of 1934, as amended, offering telecommunications and exchange access services in the Liberty, North Carolina exchange. As of July 31, 2011, Randolph served approximately 3,575 access lines in the Liberty exchange.

5. RTMC is an ILEC providing local exchange and exchange access services in the Badin Lake, Bennett, Coleridge, Farmer, High Falls, Jackson Creek, and Pisgah, North Carolina exchanges.

6. As successor to Randolph, RTMC will be the ILEC serving the Liberty exchange after the dissolution.

7. RTMC is fit, capable, and financially able to render local exchange telecommunications services in the Liberty exchange.

8. Randolph gave timely customer notice in accordance with the Commission's Order Requiring Customer Notice, and no significant protests were received subsequent to such customer notice.

9. No person or entity petitioned to intervene in this docket within the time provided in the Commission's Order.

10. The public interest will be not be harmed by the dissolution described in the Petition, and the transfer of assets from Randolph to its parent RTMC will promote the continued provision of service to existing customers of Randolph, will result in various services being made available to those customers at more favorable rates, and will enhance the ability of RTMC to provide reliable and affordable telecommunications services to the residents of this State located in its service area.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

Based upon the foregoing, the Commission finds and concludes that Randolph's request to discontinue the provision of service in the Liberty exchange as provided for in G.S. 62-118 should be granted and that Randolph, therefore, should be authorized to transfer its assets and its right and obligation to provide service in the Liberty exchange to RTMC.

The Commission further finds and concludes that Randolph should be authorized to transfer universal service provider responsibility within the Liberty exchange to RTMC. The Commission expects that RTMC will provide service in the Liberty exchange in accordance with the representations, assurances, and commitments made in the Petition and that RTMC will assume Randolph's obligation to provide service as carrier of last resort in the Liberty exchange and that RTMC will seek designation by the North Carolina Rural Electrification Authority as an Eligible Telecommunications Carrier serving the Liberty exchange.

IT IS, THEREFORE, ORDERED as follows:

1. That Randolph is authorized to discontinue the provision of service in the Liberty exchange as provided for in G.S. 62-118.

2. That, if it has not already done so, Randolph shall issue all notices described in the Petition and file a copy of such notices with the Commission within 15 days of the date of this Order.

3. That RTMC shall provide written notice to the Commission of the effective date of Randolph's dissolution, within seven (7) business days of that date. Randolph's existing Certificate of Public Convenience and Necessity will be cancelled, as of the effective date of its dissolution.

4. That, upon the effective date of Randolph's dissolution, Randolph's General Subscriber Services Tariff filed with the Commission shall be deemed cancelled and withdrawn. Likewise, on that date, references to Randolph in any other tariffs filed with the Commission shall be deemed removed and withdrawn.

5. That, on or before the effective date of its dissolution, Randolph shall cause an updated version of the Liberty exchange map to be filed with the Commission to reflect transfer of the Liberty exchange to RTMC.

6. That Randolph is granted such other and further authorizations as may be necessary for it to affect the dissolution and transfer described in the Petition.

ISSUED BY ORDER OF THE COMMISSION.
This the 22nd day of November, 2011.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

kh112211.01

WATER AND SEWER – RATE INCREASE

DOCKET NO. W-218, SUB 319

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Aqua North Carolina, Inc., 202 MacKenan Court, Cary, North Carolina 27511, for Authority to Increase Rates for Water and Sewer Utility Service in All of Its Service Areas in North Carolina	)	ORDER REQUIRING VERIFIED INFORMATION

BY THE PRESIDING COMMISSIONER: With respect to Aqua North Carolina, Inc.'s (Aqua's) pending application for a general rate increase, the Commission has now completed the decision-making process related to resolution of the issues between and among the Parties, except for the matter concerning rate case expense.[1] With respect to decisions regarding two issues, the Commission is currently in need of information that does not appear to be reasonably obtainable from the record as it presently exists. These decisions concern insurance claims and medical and dental benefits expenses. The ministerial computations are necessary to allow the Commission to quantify the effects of the subject decisions for purposes of completing the Commission's determination of Aqua's overall annual revenue requirement and to set forth accurately and specifically its findings of fact in the final order to be issued in this docket.

The Presiding Commissioner is, therefore, of the opinion, and so finds and concludes, that good cause exists to require that Aqua, in consultation with the Public Staff, if possible, or individually, if necessary, file a verified, post-hearing exhibit, not later than close of business, Monday, August 29, 2011, setting forth the following information and data[2]:

1. Provide the amounts for (1) workers compensation claims, (2) automobile claims, and (3) general liability claims, which are the three components in the five-year average of actual claims paid for North Carolina in the amount of $277,801. (For reference purposes, Fernald Exhibit I, Schedule 3-10(a), REVISED, Column c, Lines 2, 4, and 6, provides the components of the three-year average of actual claims paid for North Carolina, as shown below.) Such requested information should be provided in the following format:

	Three-Year Average	Five-Year Average
Workers' Compensation Claims (Line 2)	$214,221	?
Automobile Claims (Line 4)	13,397	?
General Liability Claims (Line 6)	38,033	?
Total	$265,651	$277,801

[1] By Order issued August 19, 2011, the Public Staff and PSS Legal Fund, Inc. (PSS) were asked to file, by August 24, 2011, a response to Aqua's August 15, 2011 Affidavit concerning updated rate case expenses.

[2] The Commission notes that PSS has not contested these issues in this proceeding. However, if PSS should desire to comment on these issues, such comments should be filed not later than close of business, Monday, August 29, 2011.

WATER AND SEWER – RATE INCREASE

2. Provide the amount that represents the average monthly medical cost based upon the Company's revised (to include the employees who opted out of insurance coverage) average monthly medical cost of $859.82, adjusted for the 90-day delay in coverage for new employees under the Company's new benefit policy for North Carolina which became effective January 1, 2011. Such response should include all underlying assumptions, supporting workpapers, and/or footnotes which detail the calculation of the adjustment to the $859.82 average monthly medical cost required to reflect the 90-day delay in coverage for new employees. Such response should be provided in the same format as Fernald Exhibit I, Schedule 3-3(a), REVISED, Lines 1-7, utilizing a percentage of salaries expensed of 74.50%. In addition, all corresponding footnotes on Fernald Exhibit I, Schedule 3-3(a), REVISED, related to such information should be revised, where necessary, and included in your response.

3. Provide the amount that represents the average monthly dental cost, adjusted to reflect zero cost for those employees who opt out of any dental plan and to reflect the impact of the 90-day delay in coverage for new employees. Such response should include all underlying assumptions, supporting workpapers, and/or footnotes which detail the calculation of the adjusted average monthly dental cost. Such response should be provided in the same format as Fernald Exhibit I, Schedule 3-3(a), REVISED, Lines 8-14, utilizing a percentage of salaries expensed of 74.50%. In addition, all corresponding footnotes on Fernald Exhibit I, Schedule 3-3(a), REVISED, related to such information should be revised, where necessary, and included in your response.

4. Provide the calculation of the total adjustment to benefits for additional positions (Fernald Exhibit I, Schedule 3-3(a), REVISED, Line 15) based upon the average monthly medical and dental costs as provided in Item Nos. 2 and 3 above. Such response should be provided in the same format as Fernald Exhibit I, Schedule 3-3(a), REVISED, utilizing a percentage of salaries expensed of 74.50%.

5. Provide the adjustment amount which reflects the employee contributions for dental based upon the dental benefit information provided in Item No. 3 above. For reference purposes, see Fernald Exhibit I, Schedule 3-3, REVISED, Line 5, Column f. As described in Footnote No. 6, on Fernald Exhibit I, Schedule 3-3, REVISED, such response should clearly set forth the total dental benefits multiplied by the percentage of salaries expensed of 74.50%, multiplied by the employee contribution rate of 20%.

6. Provide the adjustment amount for Fernald Exhibit I, Schedule 3-3, REVISED, Line 7, which reflects the average annual medical and dental costs, adjusted for the 90-day delay in coverage for new employees provided in Item Nos. 2 and 3 above. As described in Footnote No. 8, on Fernald Exhibit I, Schedule 3-3, REVISED, such response should clearly set forth all the components of the updated calculation multiplied by three open positions, multiplied by the percentage of salaries expensed of 74.50%.

7. Provide the adjustment amounts for Fernald Exhibit I, Schedule 3-3, REVISED, Line 4, Column f, which reflects the average annual medical and dental costs, adjusted for the 90-day delay in coverage for new employees provided in Item Nos. 2 and 3 above. As

described in Footnote No. 5, on Fernald Exhibit I, Schedule3-3, REVISED, such response should clearly set forth the total benefits amount multiplied by the percentage of salaries expensed of 74.50% less Line 1, Column f.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 25th day of August, 2011.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

bk082511.01

DOCKET NO. W-218, SUB 319

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Aqua North Carolina, Inc., 202	)	
MacKenan Court, Cary, North Carolina 27511, for	)	ORDER GRANTING
Authority to Increase Rates for Water and Sewer Utility	)	PARTIAL RATE INCREASE
Service in All of Its Service Areas in North Carolina	)	

HEARD IN: Winston-Salem City Hall, Council Chambers, Second Floor, 101 N. Main Street, Winston-Salem, North Carolina on Wednesday, April 6, 2011, at 7:00 p.m.

Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina on Monday, April 11, 2011, at 7:00 p.m.

Charlotte-Mecklenburg Government Center, Conference Center Meeting Room 267, 600 East Fourth Street, Charlotte, North Carolina on Tuesday, April 19, 2011, at 7:00 p.m.

District Court Building, Courtroom B, 111 Main Avenue NE, Hickory, North Carolina on Wednesday, April 20, 2011, at 7:00 p.m.

Judicial Building, Courtroom 403, 316 Princess Street, Wilmington, North Carolina on Tuesday, April 26, 2011, at 7:00 p.m.

Cliffdale Recreation Center, Multi-Purpose Room, 6404 Cliffdale Road, Fayetteville, North Carolina on Thursday, April 28, 2011, at 7:00 p.m.

Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina on Thursday, June 9, 2011, at 9:00 a.m.

WATER AND SEWER – RATE INCREASE

BEFORE: Commissioner Lorinzo L. Joyner, Presiding; Chairman Edward S. Finley, Jr.; and Commissioners Susan W. Rabon, ToNola D. Brown-Bland, and Lucy T. Allen

APPEARANCES:

For Aqua North Carolina, Inc.:

Jo Anne Sanford, Sanford Law Office, PLLC, Post Office Box 28085, Raleigh, North Carolina 27611

Daniel C. Higgins, Burns, Day & Presnell, P.A., Post Office Box 10867, Raleigh, North Carolina 27605

C. Blythe Clifford, Clifford Law Firm, PLLC, Post Office Box 37458, Raleigh, North Carolina 27627

For PSS Legal Fund, Inc.:

Gary A. Davis, Gary A. Davis & Associates, Post Office Box 649, Hot Springs, North Carolina 28743

For the Using and Consuming Public:

William E. Grantmyre and Elizabeth A. Denning, Staff Attorneys, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: On November 19, 2010, Aqua North Carolina, Inc. (Aqua NC or Company), filed a letter of intent notifying the Commission of its intent to file a general rate case application as required by Commission Rule R1-17(a).

On January 21, 2011, Aqua NC filed an application with the Commission seeking authority to increase rates for water and sewer utility service in all of its service areas in North Carolina. The application stated that Aqua NC serves approximately 72,660 water customers and 15,260 sewer customers in 48 counties throughout North Carolina.

On February 8, 2011, the Commission declared this proceeding to be a general rate case pursuant to G.S. 62-137 and suspended the proposed rates for up to 270 days pursuant to G.S. 62-134.

On February 24, 2011, C. Blythe Clifford of the Clifford Law Firm, PLLC, filed a Notice of Appearance on behalf of Aqua NC.

On March 1, 2011, the Commission issued its Order Scheduling Hearings and Requiring Public Notice. The Order required Aqua NC to file a report addressing all customer service and/or service quality complaints expressed at the hearings to be held on April 6, 11, 19, and

20, 2011, within 20 days after each customer hearing wherein complaints were expressed; and it also required Aqua NC to file a report addressing all customer service and/or service quality complaints expressed at the hearings to be held on April 26 and 28, 2011, within 15 days after each customer hearing wherein complaints were expressed.

On March 15, 2011, Aqua NC filed a Certificate of Service notifying the Commission that the required notice to customers had been provided.

On April 6, 2011, a public hearing for the purpose of receiving customer testimony was held in the Council Chambers, Winston-Salem City Hall, Second Floor, 101 N. Main Street, Winston-Salem, North Carolina as scheduled. Eighteen witnesses presented testimony at the public hearing.

On April 11, 2011, Daniel C. Higgins, of Burns, Day & Presnell, P.A., filed a Notice of Appearance on behalf of Aqua NC.

On April 11, 2011, a public hearing for the purpose of receiving customer testimony was held in the Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina as scheduled. Thirteen customers presented testimony at the public hearing.

On April 19, 2011, a public hearing for the purpose of receiving customer testimony was held in the Conference Center Meeting Room 267, Charlotte-Mecklenburg Government Center, 600 East Fourth Street, Charlotte, North Carolina as scheduled. Eleven customers presented testimony at the public hearing.

On April 20, 2011, a public hearing for the purpose of receiving customer testimony was held in Courtroom B, District Court Building, 111 Main Avenue NE, Hickory, North Carolina as scheduled. Five customers presented testimony at the public hearing.

On April 25, 2011, Aqua NC filed the testimony and exhibits of Thomas J. Roberts, President and Chief Operating Officer of Aqua NC; Stan F. Szczygiel, Manager of Rates and Planning of Aqua Services, Inc. (Aqua Services); and Shannon V. Becker, Controller of Aqua NC.

On April 26, 2011, Aqua NC filed a report addressing concerns raised by customers at the public hearing held in Winston-Salem on April 6, 2011.

On April 26, 2011, a public hearing for the purpose of receiving customer testimony was held in Courtroom 403, Judicial Building, 316 Princess Street, Wilmington, North Carolina as scheduled. Eight customers presented testimony at the public hearing.

On April 28, 2011, a public hearing for the purpose of receiving customer testimony was held in the Multi-Purpose Room, Cliffdale Recreation Center, 6404 Cliffdale Road, Fayetteville, North Carolina as scheduled. Four customers presented testimony at the public hearing.

On April 29, 2011, PSS Legal Fund, Inc. (PSS) filed a petition to intervene, which was granted by Commission Order issued May 9, 2011. PSS is a North Carolina nonprofit corporation organized for the purpose of advocating for fair water and sewer rates in North Carolina and acting on behalf of the residents in Park South Station Community located in Charlotte, North Carolina.

By agreement with the Public Staff – North Carolina Utilities Commission (the Public Staff) and pursuant to a motion made by Aqua NC and granted orally by the Commission on April 21, 2011, Aqua NC filed the testimony and exhibits of its witness Pauline M. Ahern, Principal of AUS Consultants, on May 2, 2011.

On May 2, 2011, Aqua NC filed a report addressing concerns raised by customers at the public hearing held in Raleigh on April 11, 2011.

On May 9, 2011, Aqua NC filed reports addressing concerns raised by customers at the public hearings held in Charlotte on April 19, 2011, and Hickory on April 20, 2011.

On May 11, 2011, Aqua NC filed a report addressing concerns raised by customers at the public hearing held in Wilmington on April 26, 2011.

On May 13, 2011, Aqua NC filed the updates and supporting documentation which Aqua NC had provided to the Public Staff on April 15, 2011, pursuant to Decretal Paragraph No. 5 of the Commission's March 1, 2011 Order Scheduling Hearings and Requiring Public Notice. Also, on May 13, 2011, Aqua NC filed a report addressing concerns raised by customers at the public hearing held in Fayetteville on April 28, 2011.

On May 18, 2011, the Public Staff filed a motion requesting that the Commission grant an extension of time for the filing of direct testimony by the Public Staff and PSS until May 25, 2011, and the filing of rebuttal testimony by Aqua NC until June 3, 2011. On May 19, 2011, the Commission issued an Order granting the extensions of time.

On May 23, 2011, PSS filed a Motion for Subpoena, as well as the proposed subpoena for Robert W. Burkett, President of J & B Development and Management, Inc.

On May 24, 2011, PSS filed the affidavit of Stan Coleman, M.D., who is a member of PSS and a resident in Park South Station Community wherein Aqua NC provides water and sewer utility service.

On May 24, 2011, the Public Staff made an oral motion requesting that the Commission grant a one-day extension of time for the parties to file direct testimony to extend the time for the Public Staff and PSS to file direct testimony until May 26, 2011. By Order issued May 25, 2011, the Commission granted the requested extension.

On May 25, 2011, PSS filed the testimony and exhibits of William H. Novak, President of WHN Consulting. Also, on May 25, 2011, the Commission issued the subpoena for Robert W. Burkett, as requested by PSS.

On May 26, 2011, the Public Staff filed the testimony and exhibits of Katherine A. Fernald, Water Supervisor, Public Staff Accounting Division; David C. Furr, Utilities Engineer, Public Staff Water Division; Jerry H. Tweed, Utilities Engineer, Public Staff Water Division; and John R. Hinton, Director, Public Staff Economic Research Division.

On June 3, 2011, Aqua NC filed the rebuttal testimony and exhibits of its witnesses Thomas J. Roberts; Shannon V. Becker; Stan F. Szczygiel; Pauline M. Ahern; and John J. Spanos, Vice President of Valuation and Rate Division of Gannett Fleming, Inc.

On June 6, 2011, the Commission issued an Order requiring the parties to file their recommended order of appearance for their witnesses and estimates of cross-examination times of the opposing parties' witnesses. Also, on June 6, 2011, PSS filed the Affidavit of Service of the subpoena on Robert W. Burkett.

On June 7, 2011, the Public Staff filed the supplemental testimony and exhibit of Public Staff witness Fernald.

On June 7, 2011, PSS filed a motion for leave to file the surrebuttal testimony of PSS witness Novak. On June 7, 2011, PSS filed witness Novak's proposed surrebuttal testimony and the affidavit of Robert W. Burkett. On June 8, 2011, Aqua NC filed its objection and motion to strike the proposed surrebuttal testimony of witness Novak and the affidavit of witness Burkett.

On June 8, 2011, Aqua NC filed a complete copy of Schedule PMA-6, which was referenced in the prefiled direct testimony of its witness Ahern, as several pages were unintentionally omitted from the initial filing of that schedule. Also, on June 8, 2011, the parties made filings regarding the order of their witnesses and estimated cross-examination times.

On June 9, 2011, the evidentiary hearing was held in Raleigh, North Carolina as scheduled. Two customers presented testimony. After oral argument by PSS and Aqua NC, the Presiding Commissioner denied the motion of PSS for leave to file the proposed surrebuttal testimony of witness Novak and also denied the motion to accept the affidavit of witness Burkett in lieu of personal testimony. Aqua NC presented the direct and rebuttal testimony of witnesses Ahern, Becker, Szczygiel, and Roberts, and the rebuttal testimony of witness Spanos. PSS presented the testimony of witness Novak. The Public Staff presented the direct testimony of witnesses Furr, Tweed, and Hinton and the direct and supplemental testimony of witness Fernald. Upon conclusion of the Public Staff's witness presentations, Aqua NC recalled its witness Roberts to present additional rebuttal testimony.

On June 17, 2011, Aqua NC filed a report addressing concerns raised by customers and the Commission at the evidentiary hearing held in Raleigh on June 9, 2011.

On June 27, 2011, a formal written Order was issued denying the motion of PSS for leave to file the proposed surrebuttal testimony of Mr. Novak and to accept the affidavit of Mr. Burkett in lieu of personal testimony.

On June 30, 2011, the Stipulation of Aqua NC and the Public Staff was filed (hereinafter referenced as the Joint Stipulation) concerning the Windsor Oaks system that has been paralleled by the Town of Cary and the seven systems being sold to the City of Charlotte.

As requested by the Commission during the evidentiary hearing, the Public Staff filed on June 30, 2011, a Revised Fernald Exhibit I reflecting the Public Staff's adjustments and final position regarding revenues, expenses, and rate base. The Public Staff also filed a Late Filed Exhibit I, which included a reconciliation of the difference between the Public Staff's recommended increase in revenue requirement and the Company's proposed revenue increase along with supporting workpapers of the underlying revenue requirement calculations.

On July 21, 2011, Aqua NC filed a motion requesting that the Commission grant an extension of time for the filing of briefs and proposed orders until August 1, 2011. Also, according to G.S. 62-135, Aqua NC waived any statutory rights to implement temporary rates under bond from August 19, 2011 to August 26, 2011. On July 22, 2011, the Commission issued an Order granting the extension of time.

On August 1, 2011, the parties filed their proposed orders and/or briefs.

On August 15, 2011, Aqua NC filed an Affidavit of Rate Case Expense. On August 18, 2011, counsel for Aqua NC advised the Commission that Aqua NC waived its statutory rights to implement rates under bond as afforded by G.S. 62-135, from August 26, 2011 to September 9, 2011. On August 19, 2011, the Commission issued a Post Hearing Order Requiring Response by the Public Staff and PSS to the Aqua NC affidavit by August 24, 2011. On August 24, 2011, the Public Staff filed its response to the affidavit. On August 25, 2011, PSS filed its response to the affidavit.

On August 25, 2011, the Commission issued a Post Hearing Order Requiring Verified Information to be filed by Aqua NC and the Public Staff by August 29, 2011. On August 29, 2011, Aqua NC filed the verified information requested in the Commission's Order of August 25, 2011. In the filing, Aqua NC indicated that the Public Staff had reviewed the amounts submitted by the Company and agreed with the verified amounts and Aqua NC also stated that it agreed with the Public Staff's rate case expense recommendations, as set forth in the Public Staff's August 24, 2011 filing.

On September 13, 2011, the Commission issued a Notice of Decision and Order in this proceeding. In said Order, the Commission approved an increase in rates on a provisional basis. Accordingly, a new Schedule of Rates was approved by the Commission to become effective on September 13, 2011 and customer notice was required. Thereafter, on September 23, 2011, the Commission issued an Errata Order for the correction of inadvertent errors in the name identification of a few subdivisions in the Appendices A-1, B-1, and B-2, which were attached to the September 13, 2011 Order.

Based on the application, the June 30, 2011 Joint Stipulation, the proposed orders and briefs submitted by the parties and other evidence of record, the Commission now makes the following

FINDINGS OF FACT

General Matters

1. Aqua NC is a corporation duly organized under the laws of and is authorized to do business in the State of North Carolina. Aqua NC is a franchised public utility providing water and/or sewer utility service to customers in North Carolina.

2. Aqua NC 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 all of its water and sewer operations in North Carolina.

3. The test period appropriate for use in this proceeding is the 12-month period ended July 31, 2010, updated to December 31, 2010.

4. On March 23, 2011, the Company filed an application with the Commission in Docket No. W-218, Sub 325 for authority to transfer the water and/or sewer utility systems serving the (1) Brantley Oaks, (2) McCarron, (3) Stone Mountain, (4) Timberlands, (5) Willows Creek, (6) Reedy Creek Plantation, and (7) Satterwythe Place/Alderwood service areas in Mecklenburg County, North Carolina, to the City of Charlotte, which is exempt from Commission regulation. For the month of December 2010, Aqua NC rendered 243 total water bills and 862 total sewer bills related to such systems. Upon completion of the transfer, the systems will be operated by Charlotte-Mecklenburg Utilities (CMU), a department of the City of Charlotte. On June 27, 2011, in Docket No. W-218, Sub 325, the Commission issued an Order Approving Transfer, Canceling Franchises, and Scheduling Hearing on the issue of how, if at all, the remaining ratepayers should be protected from an adverse cost impact of the transfer.

5. On May 20, 2011, the Company filed an application with the Commission in Docket No. W-218, Sub 327 for authority to discontinue providing water and sewer utility service to Windsor Oaks Subdivision since the water and sewer systems in this service area had been paralleled by the Town of Cary, which offers service to all 90 customers in the Windsor Oaks Subdivision. On July 28, 2011, in Docket No. W-218, Sub 327, the Commission issued an Order authorizing Aqua NC to abandon its water and sewer utility systems serving Windsor Oaks Subdivision effective September 1, 2011, or the date the last customer ceases to use the systems, whichever occurs first.

Agreement Among Parties

6. Pursuant to the Joint Stipulation filed on June 30, 2011 between Aqua NC and the Public Staff, the Company and the Public Staff agreed that the Windsor Oaks system and the McCarron, Reedy Creek, Willows Creek, Brantley Oaks, Satterwythe, Timberlands, and Stone Mountain systems should be removed from this rate case. The Joint Stipulation set forth the preliminary amounts to be removed from rate base, revenues, and expenses in this case for these systems.

7. The Company and the Public Staff further agreed, pursuant to the Joint Stipulation, that the rates approved by the Commission in this docket will be provisional rates, and will be adjusted to reflect the Commission's rulings in Docket No. W-218, Sub 325 concerning (1) the treatment of any gain on sale; (2) the treatment of the loss on Windsor Oaks; (3) the revenues, expenses, and rate base associated with the Windsor Oaks system and the systems being sold to the City of Charlotte; and (4) any other rulings by the Commission in the transfer proceeding which affect the rates for Aqua NC.

8. The Joint Stipulation is reasonable and appropriate and should be, and is hereby, approved.

Customer Concerns and Service

9. For the month of December 2010, Aqua NC rendered 71,971 total water bills and 15,102 total sewer bills composed of the following total number of bills for each service area: 54,313 in Aqua water; 12,640 in Aqua sewer; 14,165 in Brookwood water; 3,493 in Fairways water; and 2,462 in Fairways sewer.

10. A total of 61 customers testified at the six public hearings and the evidentiary hearing, with 14 of those customers expressing service-related concerns. Such concerns included complaints regarding hard water buildup on fixtures; delayed road repairs; lengthy water outages; discolored water; improper billing for some sewer-only customers who were not being billed immediately upon move-in; and other billing issues. In addition, the majority of the remaining customers who appeared as witnesses testified, generally, in opposition to the proposed rate increase and/or the existing rate design.

11. Aqua NC filed seven reports with the Commission, verified by Company President Thomas J. Roberts, addressing the service-related concerns expressed by the public witnesses who testified at the public hearings and the evidentiary hearing. Such reports described each of the witnesses' specific service-related concerns, the Applicant's response, and how each concern was addressed, if applicable.

12. The overall quality of service provided by Aqua NC to its customers is adequate.

Park South Station Matters

13. PSS witness Novak testified that the current residents of Park South Station paid for the entire water and sewer systems when they first purchased their lots and homes because such costs are typically passed on by a developer to the purchasers of lots and homes. Further, witness Novak testified that the Park South Station developer stated in an affidavit that the infrastructure costs were built into the sale of land and that witness Novak relied upon the developer's affidavit and his general knowledge to form his opinion that the total infrastructure costs were built into the sale of the lots in Park South Station.

14. PSS did not present the developer as a witness so that the developer's statement could be confirmed under oath, with the ability of the parties to cross-examine the developer

concerning his statement. PSS did not provide copies of the Park South Station developer's tax returns or other documentation showing how the developer handled both the cost of the water system and the payments received from Aqua NC.

15. The current residents of Park South Station have not paid for the entire water and sewer systems through the purchase of lots or other payments.

16. Commission Rule R18-6 is not applicable to Aqua NC as a public utility seeking to adjust its rates pursuant to G.S. 62-133.

17. It is appropriate and reasonable for Aqua NC to charge its consolidated monthly base facility rates to the Park South Station water and sewer customers and to charge such customers the applicable usage charges, as set forth in the Schedule of Rates, attached hereto, based on the rates Aqua NC pays to the City of Charlotte. It is appropriate for Aqua NC to continue to collect its currently authorized $700 connection fee for the Park South Station Service Area.

18. The contract between the developer of Park South Station and Aqua NC's predecessor in interest, Heater Utilities, Inc. (Heater), which was filed in Docket No. W-274, Sub 653, indicated that the developer sold the Park South Station water utility system to Heater for $1,200 per single family residential equivalent (SFRE) and contributed the sewer utility system to Heater. At the time that the contract was executed and the transfer was consummated, the assets being transferred were not being used to provide water and sewer utility service to customers for compensation and the developer was not operating the system as a public utility. For purposes of this ratemaking proceeding, the developer is recovering the system costs as specified in said contract.

19. Aqua NC was the first entity to devote the Park South Station property being acquired to public utility service.

20. Aqua NC has properly accounted for the purchase of the Park South Station water and sewer infrastructure in the manner required by the National Association of Regulatory Utility Commissioners (NARUC) Uniform System of Accounts.

21. It is inappropriate to adjust rate base by making a plant acquisition adjustment resulting from Heater's acquisition of the Park South Station assets.

Rate Base

22. It is appropriate to make excess capacity adjustments to disallow a portion of the Company's investment in two of its wastewater treatment plants (WWTPs) as follows:

Carolina Meadows WWTP	31.89%
The Legacy at Jordan Lake WWTP	94.33%

23. The appropriate level of original cost rate base used and useful in providing water and sewer utility service for Aqua NC's combined operations (including Aqua water and sewer,

Fairways water and sewer, and Brookwood water) is $119,387,426, which is composed of the following amounts:

Aqua Water	$ 79,408,555
Aqua Sewer	23,163,397
Fairways Water	2,231,251
Fairways Sewer	2,744,749
Brookwood Water	11,839,474
Total Combined Operations	$119,387,426

24. Aqua NC had the following water and sewer plant in service amounts at the end of the test year, including pro forma adjustments, composed of the following:

Aqua Water	$200,960,989
Aqua Sewer	103,431,945
Fairways Water	8,070,647
Fairways Sewer	7,271,902
Brookwood Water	26,900,864
Total Combined Operations	$346,636,347

25. Accumulated depreciation at the end of the test year, including pro forma adjustments, consisted of the following amounts:

Aqua Water	$ 68,337,739
Aqua Sewer	26,277,579
Fairways Water	1,713,827
Fairways Sewer	1,162,720
Brookwood Water	10,999,160
Total Combined Operations	$108,491,025

26. Contributions in aid of construction (CIAC) reduced by accumulated amortization of CIAC, advances for construction, and acquisition adjustments (AA) including accumulated amortization of AA total to the following amounts at the end of the test year, including pro forma adjustments:

Aqua Water	$ 50,499,318
Aqua Sewer	51,866,871
Fairways Water	3,823,198
Fairways Sewer	3,074,925
Brookwood Water	3,377,022
Total Combined Operations	$112,641,334

27. The appropriate level of working capital allowance for the combined operations for use in this proceeding is $2,427,757, which is composed of the following:

Aqua Water	$1,531,507
Aqua Sewer	590,969
Fairways Water	49,186
Fairways Sewer	64,626
Brookwood Water	191,469
Total Combined Operations	$2,427,757

28. The appropriate level of accumulated deferred income taxes (ADIT) for the combined operations for use in this proceeding is $7,610,422, which is composed of the following:

Aqua Water	$4,783,739
Aqua Sewer	1,400,233
Fairways Water	337,090
Fairways Sewer	352,999
Brookwood Water	736,361
Total Combined Operations	$7,610,422

29. In accordance with Provision 8 of the June 30, 2011 Joint Stipulation filed in this proceeding by the Public Staff and Aqua NC, the rates approved by the Commission are provisional rates. The provisional rates should be adjusted to reflect any adjustments to ADIT associated with the transfer of the seven systems to CMU, as recommended by the Company, which will be reflected in the Commission's rulings in Docket No. W-218, Sub 325.

Revenues

30. The $28,069 in commissions paid by the Company to Utility Services Communications Company, Inc. (USC) in connection with antenna leases secured by that firm are expenses actually incurred by the Company in connection with leases for placement of antennas on Company water tanks. These expenses are appropriate and reasonable and should be included as a reduction in the Company's miscellaneous revenues.

31. The appropriate level of total operating revenues for Aqua NC's combined operations under present rates for use in this proceeding is $44,346,303, consisting of service revenues of $43,234,707; late payment fees of $114,453; and miscellaneous revenues of $1,322,706; reduced by uncollectibles of $325,563. Aqua NC's present service revenues of $43,234,707 are comprised of the following water and sewer service revenues:

Aqua Water	$27,268,704
Aqua Sewer	9,582,238
Fairways Water	752,240
Fairways Sewer	980,666
Brookwood Water	4,650,859
Total Combined Operations	$43,234,707

WATER AND SEWER – RATE INCREASE

32. Aqua NC initially requested an increase in its water and sewer utility rates that would produce total additional service revenues of $8,216,073, as shown below. However, in its Proposed Order, the Company revised its request to produce the following total additional service revenues of $4,491,442, as indicated:

	Company Initial Request	Company Revised Request
Aqua Water	$5,399,940	$3,221,125
Aqua Sewer	1,631,652	658,258
Fairways Water	306,480	226,534
Fairways Sewer	120,161	118,400
Brookwood Water	757,840	267,125
Total Combined Operations	$8,216,073	$4,491,442

Operating, Maintenance, and General Expenses

33. It is appropriate to calculate Aqua NC's salaries and wages expense based upon the actual number of employees of 168, as of the hearing date.

34. The appropriate overall labor capitalization percentage for use in this proceeding is 24.63% based upon historical data for the 12 months ended March 31, 2011. Accordingly, overtime hours used to calculate salaries and wages should also be adjusted to reflect the hours worked for the 12 months ended March 31, 2011.

35. The Public Staff's adjustment to decrease salaries and wages expense by $71,491 and employee benefits by $18,303 to remove time spent on nonutility work and acquisitions is appropriate and should be made in this proceeding. Aqua NC's information technology (IT) and business development employees perform work for other states. This time should be properly charged to those states and should not be included in expenses for North Carolina. Aqua NC did not provide any information on the potential acquisitions that its employees worked on during the 12 months ended March 31, 2011, for which it is now requesting rate recovery from current customers. Although the Company contends that revisions should be made to the Public Staff's adjustments to remove time spent by Aqua employees on acquisitions and performing work for affiliated companies, the Company failed to provide evidence for the amounts of any adjustments.

36. The level of executive compensation included by the Company in regulated expenses for four top executives of Aqua America, Inc., (Aqua America) the parent company of Aqua NC, is unreasonable and overstated because: (1) the Company has not properly accounted for the time spent by executives on acquisitions; (2) the Company has not properly accounted for the time spent by employees on lobbying activities; (3) the Company has not properly accounted for executive time spent on capital work activities; and (4) there has been a dramatic increase in the compensation for four top executives over the past three years that has not been proven to be a reasonable increase to be recovered from ratepayers.

37. The Public Staff's proposed adjustment to remove 50% of the salaries and related expenses for four top executives of Aqua America is not appropriate.

38. It is appropriate to reduce the salaries and related benefits expenses for four top executives of Aqua America charged to North Carolina customers by 25%. Accordingly, the executive compensation for four top executives of Aqua America charged to North Carolina customers should be reduced by $78,440. It is also appropriate to make a corresponding adjustment to remove 25% of the rent charged to North Carolina customers resulting in a decrease in rent expense of $1,666.

39. The Company's cost of providing medical and dental insurance benefits for new employees who have not yet selected their insurance coverage should reflect Aqua NC's reasonable costs in that regard, which is $644.87 per month, per employee for medical benefits and $40.46 per month, per employee for dental benefits. These monthly amounts have been determined based upon the Company's average annual medical and dental benefits cost, respectively, adjusted to reflect the Company's new insurance benefits policy, effective January 1, 2011, which imposes a 90-day delay from when an employee starts with the Company and when he or she is eligible for medical and dental benefits. It is appropriate to decrease Aqua NC's medical benefits expense by $55,674 and its dental benefits expense by $2,542 to reflect a reasonable level of medical and dental insurance benefits for the new employees in this proceeding.

40. Based upon the three-year historical average, the Company's fuel cost price is $2.77 per gallon for unleaded gasoline and $3.08 for diesel. These are the appropriate prices to use in determining transportation fuel expense in this proceeding.

41. The appropriate sewer jetting expense to be included in contractual services – other, is $88,647 for Aqua sewer, and $18,508 for Fairways sewer, based on 10% compliance jetting of gravity mains per year (less Cannonsgate), plus annual maintenance jetting and unplanned jetting related to problems and/or emergencies.

42. The $277,808 five-year average of actual insurance claims paid is the reasonable amount for use in this proceeding, consistent with the methodology used in the Company's recent prior rate case proceedings and based upon review of the three-, four-, and five-year averages for claims paid. The appropriate level of insurance claims expense to be included in this case is $226,607, which properly reflects that workers compensation and automobile claims paid should be allocated to this expense based on the percentage of salaries expensed of 74.5% and that the general liability claims paid should be 100% included.

43. Aqua NC's actual expense of $30,024 for water filter backwash hauling for the Chesapeake Point system is reasonable. The fact that this system had 32 of 95 projected residences on line at the end of the test year does not affect the validity and necessity of this expense.

44. The appropriate levels of operating, maintenance, and general expenses under present rates for Aqua NC are as follows:

WATER AND SEWER – RATE INCREASE

Aqua Water	$14,558,399
Aqua Sewer	5,609,012
Fairways Water	519,969
Fairways Sewer	546,989
Brookwood Water	2,577,546
Total Combined Operations	$23,811,915

45. Aqua NC's total rate case costs are $595,705, as agreed to by Aqua NC and the Public Staff, consisting of $377,527 in costs for the current proceeding; $48,342 for the depreciation study; $14,800 for the study on volumetric sewer rates and an increasing block rate structure for water; and $155,036 in unamortized balances from the Company's two most recent prior rate case proceedings, Docket Nos. W-218, Subs 274 and 301. The rate case costs should be amortized over three years, except that the depreciation study costs should be amortized over five years, resulting in annual rate case expenses as follows:

Aqua Water	$111,570
Aqua Sewer	25,031
Fairways Water	6,904
Fairways Sewer	4,838
Brookwood Water	43,779
Total Combined Operations	$192,122

Depreciation and Amortization Expense

46. An adjustment to remove $69,725 of depreciation and amortization expense related to excess capacity in two wastewater treatment plants (Carolina Meadows and the Legacy at Jordan Lake) should be made in this proceeding.

47. On November 29, 2010, in Docket No. W-218, Sub 274, Aqua NC filed a depreciation study prepared by Gannett Fleming, Inc., pursuant to Decretal Paragraph No. 13 of a Commission Order, issued April 8, 2009, in that docket. The Gannett Fleming depreciation study encompasses group depreciation procedures. The depreciation rates set forth in said depreciation study are a reasonable and appropriate basis for setting water and sewer rates in this proceeding and are proper for the Company to use in booking depreciation expenses going forward except for the depreciation rate of 25.73% for the computer equipment account (Account 340.10).

48. The Company has $2,430,242 of 2006 IT assets, which include costs related to the implementation of the call centers and the conversion of the billing system, that were depreciated over a five-year life in prior rate cases. Based on the depreciation rate of 25.73% proposed by the Company in the depreciation study, the Company has included $625,301 in annual depreciation expense related to these 2006 IT assets.

49. Historically and currently, the Company has not used group depreciation. Instead, depreciation rates for each asset have been applied based on the year an asset was placed in service and depreciation expense stopped being calculated when the asset was fully depreciated.

It is not appropriate to include in rates an annual level of depreciation expense of $625,301 for the 2006 IT assets which have been fully depreciated as of June 30, 2011.

50. The 2006 IT assets should be removed from the computer equipment group and should receive special amortization. Since the IT assets have been updated through March 31, 2011, the unamortized balance for the 2006 IT assets, as of March 31, 2011, which is $121,514, should be amortized over three years, resulting in an annual level of amortization expense of $40,505. The appropriate depreciation rate for the computer equipment account (Account 340.10) is 25.48%, which reflects the removal of the 2006 IT assets from the general group of computer equipment.

51. It is appropriate to include in depreciation expense the net salvage value for the water plant accounts for supply mains, distribution and transmission mains, and services, and for the sewer plant accounts for gravity mains, force mains, and services. The appropriate depreciation rates for these accounts are as follows:

Account 309 – Water Supply Mains	1.91%
Account 331 – Water T&D Mains	1.61%
Account 333 – Water Services	2.40%
Account 360 – Sewer Force Mains	2.00%
Account 361 – Sewer Gravity Mains	2.00%
Account 363 – Sewer Services	2.55%

52. The appropriate level of depreciation and amortization expense for Aqua NC's combined operations for use in this proceeding is $6,530,688.

Other Taxes and Section 338(h) Adjustment

53. It is appropriate to reduce payroll taxes by $1,304 to reflect the Commission's findings and conclusions concerning the appropriate level of executive compensation expense.

54. The appropriate level of payroll taxes for Aqua NC's combined operations for use in this proceeding is $579,361, composed of the following:

Aqua Water	$384,585
Aqua Sewer	115,285
Fairways Water	13,139
Fairways Sewer	12,138
Brookwood Water	54,214
Total Combined Operations	$579,361

55. The appropriate level of property taxes, other taxes, and Section 338(h) adjustment for Aqua NC's combined operations for use in this proceeding is $317,139, consisting of property taxes of $488,835, other taxes of $219, and a reduction of $171,915 for the Section 338(h) adjustment. The $317,139 for the combined operations is composed of the following:

Aqua Water	$250,091
Aqua Sewer	(24,734)
Fairways Water	43,724
Fairways Sewer	794
Brookwood Water	47,264
Total Combined Operations	$317,139

Regulatory Fee, Gross Receipts Tax, and Income Taxes

56. It is reasonable and appropriate to calculate regulatory fees based upon the approved levels of revenues and the statutory rate of 0.12%. The appropriate level of regulatory fees for Aqua NC's combined operations for use in this proceeding is $55,942, comprised of the following:

Aqua Water	$35,602
Aqua Sewer	11,945
Fairways Water	1,202
Fairways Sewer	1,250
Brookwood Water	5,943
Total Combined Operations	$55,942

57. It is reasonable and appropriate to calculate gross receipts taxes based upon the approved levels of revenues, excluding the amount of revenues which are not subject to gross receipts taxes, and the statutory rates of 4% for water operations and 6% for sewer operations. The appropriate level of gross receipts taxes for Aqua NC's combined operations for use in this proceeding is $2,049,429, comprised of the following:

Aqua Water	$1,164,715
Aqua Sewer	596,447
Fairways Water	37,679
Fairways Sewer	62,472
Brookwood Water	188,116
Total Combined Operations	$2,049,429

58. A domestic production activities deduction of $85,246, as recommended by the Public Staff, should be included as a deduction in developing taxable income for purposes of determining the appropriate level of federal income tax expense properly includable in the test-period cost of service for purposes of this proceeding.

59. It is reasonable and appropriate to calculate the state and federal income taxes based upon the approved levels of operating income and the corporate rates of 6.9% for state income taxes and 35% for federal income taxes.

60. The appropriate level of state income taxes for Aqua NC's combined operations for use in this proceeding is $685,015, comprised of the following:

Aqua Water	$455,320
Aqua Sewer	133,566
Fairways Water	12,703
Fairways Sewer	15,827
Brookwood Water	67,599
Total Combined Operations	$685,015

61. The appropriate level of federal income taxes for Aqua NC's combined operations for use in this proceeding is $3,205,122, comprised of the following:

Aqua Water	$2,127,708
Aqua Sewer	630,760
Fairways Water	58,560
Fairways Sewer	74,742
Brookwood Water	313,352
Total Combined Operations	$3,205,122

Overall Cost of Capital

62. The appropriate capital structure to employ for use in determining the Company's revenue requirement is 50.42% long-term debt and 49.58% common equity.

63. The appropriate cost rate for long-term debt is 5.56%.

64. The proper cost of common equity capital for purposes of this proceeding is 10.20%.

65. Based upon the foregoing findings with respect to the proper capitalization ratios and the appropriate cost rates for each component of capital, the overall fair rate of return which the Company should be allowed an opportunity to earn on its original cost rate base is 7.86%.

Rates, Fees, and Other Matters

66. Aqua NC's water and sewer rates should be changed by amounts which, after pro forma adjustments, will produce the following increases in operating revenues:

Aqua Water	$1,753,730
Aqua Sewer	279,675
Fairways Water	171,394
Fairways Sewer	65,197
Brookwood Water	2,774
Total Combined Operations	$2,272,770

These increases will allow Aqua NC the opportunity to earn a 7.86% overall rate of return, which the Commission has found to be reasonable upon consideration of the findings in this Order.

WATER AND SEWER – RATE INCREASE

67. Aqua NC is entitled to changes in its water and sewer rates that will produce the following total operating revenues:

	Service Revenues	Other Revenues & Uncollectibles	Total Operating Revenues
Aqua Water	$29,029,862	$ 638,580	$29,668,442
Aqua Sewer	9,863,153	91,252	9,954,405
Fairways Water	924,049	77,758	1,001,807
Fairways Sewer	1,046,213	(4,176)	1,042,037
Brookwood Water	4,653,662	298,720	4,952,382
Total Combined Operations	$45,516,939	$1,102,134	$46,619,073

68. Aqua NC's total operating revenue deductions under the approved rates are as follows for water and sewer operations:

Aqua Water	$23,426,524
Aqua Sewer	8,133,642
Fairways Water	826,419
Fairways Sewer	826,287
Brookwood Water	4,021,739
Total Combined Operations	$37,234,611

69. Customer interest in metered sewer rates was expressed during Aqua NC's last general rate case proceeding (Docket No. W-218, Sub 274) and also in the present case.

70. Aqua NC provides water service to more than 60% of its sewer customers, with most of the remaining customers receiving water service from a third-party water provider (generally governmental).

71. Aqua NC contacted all third-party water providers regarding the possibility of obtaining water meter reading data or services for potential metered sewer billing, but has not followed up with any firm commitments.

72. In this case, testimony was presented that highlighted the advantages and disadvantages of metered versus flat monthly sewer rates.

73. Aqua NC's currently approved tariff includes metered commercial sewer rates with a monthly base charge for zero usage for residential size (less than one inch) meters of $23.13 for its Aqua sewer service areas and $11.44 for its Fairways sewer service areas.

74. The Public Staff proposed a residential metered sewer rate with the same monthly base charge as previously approved for residential size commercial customers, while the Company advocated a higher flat-rate fee for residential customers.

75. There is no compelling reason provided in this proceeding to deviate from the flat-rate sewer rate design for residential customers now in place and, therefore, the Public Staff's proposed volumetric rate design for sewer utility service will not be adopted.

76. The Schedule of Rates reflecting the Commission decisions in this matter has been previously approved, on a provisional basis, by the Commission. Such just and reasonable rates became effective September 13, 2011, pursuant to the Commission's Notice of Decision and Order issued September 13, 2011, as corrected and affirmed by Errata Order issued September 23, 2011. As set forth in the Joint Stipulation, these rates will be provisional rates pending the Commission's ruling in Docket No. W-218, Sub 325.

77. The Company should revise its accounting practices such that costs incurred related to pending acquisitions, including both costs incurred at the state level and costs allocated to North Carolina from corporate or other affiliates, should not be recorded in above-the-line expenses. Costs related to consummated acquisitions should be capitalized as part of the cost of acquiring the system and will be subject to review for reasonableness and prudence in a future proceeding before the Commission.

78. The Company should revise its accounting practices such that all legal fees, including those incurred at the state level and amounts allocated from corporate, are properly accounted for on its books.

79. The Company should expand the information provided in its current annual report filed with the Commission related to the Heater Acquisition Incentive Account, which is required by final Order dated April 8, 2009 in Docket No. W-218, Sub 274, Decretal Paragraph No. 19, such that each future annual report will provide cumulative information regarding all activity to date, as well as the status of matters currently in progress.

80. The current annual reporting requirement related to the Heater Acquisition Incentive Account required by final Order dated April 8, 2009 in Docket No. W-218, Sub 274 should be revised as follows: That Aqua NC shall file an annual report on June 30th of each year on the cumulative status of the Heater Acquisition Incentive Account. Such report shall provide a listing of the name of each company or system acquired; the corresponding docket number in which such treatment was approved by the Commission; and the purchase price for each company or system. In addition, such report shall include, for each system or company acquired, a description of all improvements made to date; an accounting of all money spent on improvements such that the total dollar amount expended is shown; a detailed description of the improvements still to be made; an estimate of the total dollar amount related to improvements still to be made; and a timeframe for the remaining improvements to be completed. Such report shall provide a summary schedule which sets forth the total amount of the Heater Acquisition Incentive Account, the amount used to date, and the remaining balance in the Heater Acquisition Incentive Account.

81. All future reports related to the two annual reporting requirements established in Docket No. W-218, Sub 274 by Decretal Paragraph Nos. 7 and 19, as modified herein, regarding Aqua NC's analysis of the terms of its debt issues and the Heater Acquisition Incentive Account,

respectively, should be filed in Docket No. W-218, Sub 319A, until further order of the Commission.

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

The evidence supporting these findings of fact is contained in the Company's application and in the Commission's records. These findings are primarily jurisdictional and informational and are uncontested.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4 THROUGH 8

The evidence supporting these findings of fact is contained in the Commission's records and in the Joint Stipulation entered into by Aqua NC and the Public Staff on June 30, 2011, which is not opposed by any party.

The Commission is of the opinion that, as proposed in the Joint Stipulation, it is appropriate that all applicable rate base, revenues, and expenses related to the seven systems being transferred to CMU, as well as the rate base, revenues, and expenses associated with the abandonment of the Windsor Oaks systems, should be removed from this rate case proceeding and should be dealt with as provided for in the Joint Stipulation. The Commission finds and concludes that the Joint Stipulation is reasonable and appropriate and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The evidence supporting this finding of fact is contained in the testimony of Public Staff witness Tweed and in Tweed Exhibit I, and it is uncontested.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 10 THROUGH 12

The evidence supporting these findings of fact is contained in the testimony of the public witnesses; in the testimony of Public Staff witness Furr and Company witness Roberts; in Aqua NC's Report on Customer Concerns From Public Hearing: Winston-Salem, filed on April 26, 2011; in Aqua NC's Report on Customer Concerns From Public Hearing: Raleigh, filed on May 2, 2011; in Aqua NC's Report on Customer Concerns From Public Hearing: Charlotte, filed on May 9, 2011; in Aqua NC's Report on Customer Concerns From Public Hearing: Hickory, filed on May 9, 2011; in Aqua NC's Report on Customer Concerns From Public Hearing: Wilmington, filed on May 11, 2011; in Aqua NC's Report on Customer Concerns From Public Hearing: Fayetteville, filed on May 13, 2011; and in Aqua NC's Report on Concerns From Evidentiary Hearing in Raleigh, filed on June 17, 2011.

Six public hearings were held across the State for the benefit of public witnesses. Public witnesses were also heard at the evidentiary hearing which was held in Raleigh. Sixty-one public witnesses testified during those seven hearings; all objecting to the rate increase, the existing rate design, and/or describing service-related concerns as follows:

WATER AND SEWER – RATE INCREASE

Hearing	Public Witnesses
Winston-Salem (April 6, 2011)	18
Raleigh (April 11, 2011)	13
Charlotte (April 19, 2011)	11
Hickory (April 20, 2011)	5
Wilmington (April 26, 2011)	8
Fayetteville (April 28, 2011)	4
Raleigh (June 9, 2011)	2
Total	61

Of Aqua NC's approximately 71,971 water customers and its 15,102 sewer customers in 48 North Carolina counties, approximately 14 customers expressed service-related concerns. The majority of the public witnesses objected to the magnitude of the increase and/or to the flat rate sewer design, and some expressed opposition to uniform rates as opposed to system-specific rates.

In response to the customers' complaints, Aqua NC filed seven reports with the Commission, verified by Company President Thomas J. Roberts (collectively referenced as Reports on Customer Concerns) addressing the service-related concerns expressed by the public witnesses who testified at the hearings held in this docket. Such reports described each of the witnesses' specific service-related concerns, the Applicant's response, and how each concern was addressed, if applicable. In addition, the reports provided certain details regarding operational and/or capital improvements that have been made to the systems from which the service-related concerns originated or set forth the improvements which are planned to be made to such systems in the near future.

In the Reports on Customer Concerns, Aqua NC reported that it had contacted, or attempted to contact, all the customers who presented a service-related concern. The Company described its efforts to make corrections where remedial acts were warranted, and reported that in some instances the Company's records and the customers' testimony were not consistent.

With respect to the customers' service-related concerns related to water quality, Aqua NC reported that it is in compliance with the applicable water quality laws and described the treatment, filtration, and flushing protocols which it uses to attempt to deal with water quality issues. Aqua NC described its ongoing efforts to improve water treatment.

A few customers expressed concerns about billing, noting that some sewer-only customers had not been billed. Aqua NC stated in its Reports on Customer Concerns that every six months Aqua NC now performs a field audit of all sewer-only systems that are not built out to ensure that the Company is billing all sewer-only customers.

A number of customers objected to the flat-rate mechanism for recovery of sewer costs. This issue was addressed in Aqua NC's Reports on Customer Concerns and in the testimony of Public Staff witness Tweed, and is addressed specifically later in this Order.

Public Staff witness Furr testified that, with few exceptions, Aqua NC was providing adequate water and sewer service. He further testified that where problems exist the Company has either corrected such problems or was working actively to do so. Witness Furr stated that his investigation revealed that the facilities, such as well houses and tanks, were well maintained and functioning properly and that the improvements underway would add to the reliability and consistency of water quality and service.

Based upon the foregoing, the Commission finds and concludes that the overall quality of service provided by Aqua NC is adequate.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 13 THROUGH 21

The evidence supporting these findings of fact is contained in the testimony of Company witness Roberts and PSS witness Novak.

PSS witness Novak testified that in his opinion the residents of Park South Station have already paid for their water and sewer plant when they first purchased their homes from the developer, as such costs are typically passed on by a developer to the purchasers of lots and homes. For that reason, witness Novak testified that the Commission should recognize a negative acquisition adjustment in rate base equal to the purchase price paid by Aqua NC to the developer for Park South Station. As a result, witness Novak recommended that the entire plant cost recorded to date of $1,334,129, consisting of $466,137 for water plant and $867,992 for sewer plant, should be reflected as a deduction to rate base in this case. Witness Novak also asserted that the current $700 connection fee for Park South Station should be eliminated, since customers have already paid for the cost of the water and sewer plant for this system. On cross-examination, witness Novak explained that he is relying on the developer's statement that the infrastructure costs were built into the sale of land and his own work experience with other developments where the developers, as a general rule, intend to make money and intend to recover their costs, including their infrastructure costs. Witness Novak further contended that typically developers only have one revenue stream, lot sales, from which to recover the cost of water and sewer systems. However, on cross-examination, witness Novak acknowledged that Park South Station is not the typical situation, since in this case the developer has a second revenue stream.

On cross-examination, Company witness Roberts observed that the system-wide base facility charges recommended by Aqua NC are substantially higher than the nonusage based administrative fee imposed by CMU on its water and sewer customers. Company witness Roberts also testified that, although Aqua NC is responsible for maintaining the distribution and collection system in Park South Station, there has yet to be any known maintenance that Aqua NC was required to perform on the system. PSS witness Novak stated that the main role that Aqua NC would be required to perform as the operator of a relatively new system would primarily be to provide meter readings. Because of the limited utility functions that Aqua NC[1] would be providing to its Park South Station customers, PSS witness Novak argued that Aqua

[1] Aqua NC does not treat the water, operate any wells, operate a water treatment plant, analyze the water independent of CMU, operate a sewage treatment plant, purchase any chemicals for treatment of sewage, or dispose of sewage sludge.

NC should only be permitted to charge the nominal administrative fee, i.e. $3.75, established by the Commission in Commission Rule R18-6, the Chapter that governs the provision of water and sewer services by landlords. PSS witness Novak also asserted that the Commission-established nominal fee is appropriate because Aqua NC provides services similar to those that a landlord reseller provides to tenants, i.e., meter reading, billing, and collections[1] and not the additional services normally provided by a water and sewer public utility. Additionally, PSS witness Novak testified that Aqua NC should have no rate base for its system in Park South Station.

In this proceeding, Aqua NC has proposed to charge customers residing in the Park South Station service area the same water and sewer usage rates that CMU is charging Aqua NC. All the parties agreed that it is appropriate for Aqua NC to charge the Park South Station customers usage rates in this manner. However, in this proceeding, Aqua NC also seeks to charge monthly system-wide base facility charges of $18.50 for water and $26.34 for sewer to its Park South Station customers.[2] The Public Staff agreed with Aqua NC that it is appropriate to charge Park South Station customers the system-wide base facility charge for water and sewer customers. However, the Public Staff contended that the monthly system-wide base facility rates for water and sewer should be $15.76 and $23.13, respectively, and should be applicable to Park South Station customers. PSS objected to Aqua NC's and/or the Public Staff's proposal to charge the system-wide base facility charges for water and sewer to Park South Station customers.[3]

Instead of subjecting Park South Station customers to either Aqua NC's or the Public Staff's proposed standard base facility charges for water and sewer services that the majority of Aqua NC's customers would be required to pay, PSS argued that Park South Station residents should be subject to unique "standalone rates" for the water and sewer services that Aqua NC provides to them. PSS asserted that the treatment that it proposes is appropriate because of the unique circumstances in the Park South Station service area and because the standalone rate that it proposes is more reasonably related to Aqua NC's true costs of providing service to that area. Further, PSS contended that Aqua NC should have no rate base for its system in Park South Station.

PSS advanced several additional theories in support of its arguments. First, PSS asserted that the Park South Station ratepayers have paid for the water and sewer infrastructure several times; consequently, there should be a plant acquisition adjustment offsetting any costs Aqua NC has or will incur in acquiring the Park South Station assets. PSS maintained that the ratepayers have paid for the water and sewer assets through the price they paid to the Park South developer for their lots. PSS maintained that the costs of the developer in the water and wastewater assets conveyed to Aqua NC are less than the price Aqua NC paid for them, and even if the

[1] Commission Rule R18-6 provides that a landlord purchasing water and sewer utility service from a supplier and charging for providing the service or services to tenants may charge a Commission-approved administrative fee not to exceed $3.75 to compensate the provider for meter reading, billing, and collection.

[2] Base facility charges are separate administrative fees that Aqua NC charges its water and/or sewer service customers in addition to the commodity usage rate.

[3] Aqua NC agreed that PSS customers would be billed the identical commodity charge that CMU bills Aqua NC for water and sewer service. Thus, the issue in dispute in these proceedings is whether Aqua NC should be permitted to charge the system-wide base facility charges for water and sewer service to its PSS customers or should Aqua NC be required to establish a standalone base facility rate for the PSS customers.

Commission disagreed that the cost of the assets were recovered from ratepayers through lot sales, Aqua NC should record a plant acquisition adjustment to remove from rate base the alleged excess of purchase price paid by Aqua NC over the developer's costs. Finally, PSS claimed that without a legitimate investment in the PSS system, Aqua NC over-recovers its capital costs by assessing a connection fee.

For PSS' arguments to result in any meaningful benefit to the Park South Station ratepayers, PSS must prevail in its assertion that rates should be established for Park South Station on a standalone, system-specific basis. The Commission finds that with the exception of altering the commodity element of the rate charged customers like those in Park South Station where Aqua NC acquires wholesale water production and sewer treatment from third parties, it will not depart from its determination that Park South Station should be subject to Aqua NC's uniform rates.

Utility rates are established on average costs for classes of consumers. Consumer classes and individuals within the class may impose widely different costs on the utility. Nevertheless, it is not practical, reasonable, or cost effective to track costs on an individual system basis and maintain hundreds of different rates for Aqua NC. The Commission recognizes that operating and administrative costs are reduced under uniform rates. Under uniform rates, some customers in any given case pay more than the costs to serve them; some pay less. In subsequent cases, however, the temporary imbalance may be reversed. Aqua NC must maintain a sewer lift station in Park South Station. When and if the lift station malfunctions and must be replaced, Park South Station's customers may be subsidized by others.

PSS has failed to support its allegation that existing ratepayers or future ones in the subdivision have paid or will pay for the water and sewer systems in the purchase price of the lot. It is far from clear from the record that the ultimate homeowners and ratepayers have or will acquire their residence from the developer as opposed to a builder or other intermediary. While every developer hopes at the time of full build-out to have recovered all of his costs and to make a handsome profit as well, the price of lots in this non-regulated context is determined by what the market will bear. Developers do not price their lots on cost of service principles as do public utilities in establishing their rates. Most of the lots in Park South Station have not been sold. Depending on future economic conditions, the Park South Station developer may be required to sell many lots at a loss.

The Park South Station developer negotiated a contract with Aqua NC's predecessor in interest under which it receives $1,200 per connection in reimbursement for the water and sewer assets. This is concrete evidence that contradicts the unsupported, hearsay argument of witness Novak that the developer recovers all of its costs through lot sales. Developers do not maintain books in compliance with the National Association of Regulatory Utility Commissioners (NARUC) Uniform System of Accounts. Instead, they seek to minimize income tax expense and maximize short-term profits. The Commission does not accept PSS' arguments that Aqua NC has no investment in the Park South Station assets recoverable through rates because the developer has or will recover the costs through lot sales.

Next, PSS argues that Aqua NC's purchase price exceeds the developer's book costs and an acquisition adjustment should be made to recognize these facts. PSS' evidence in support of this theory is not credible. PSS has examined several Aqua NC journal entries made over a limited period of time for the water system indicating that, for the conveyance at issue, the $1,200 per connection that Aqua NC pays for the water assets exceeds what the developer lists as its costs. However, PSS completely ignores the entries for the sewer system on the same general ledger documents. Under the Aqua NC contract with the developer, all of Aqua NC's payments to the developers are credited against the costs of the water assets; none against the sewer assets. Moreover, Aqua NC Becker Redirect Exhibit No. 1 shows that at full build-out, Aqua NC's total investment in the Park South Station assets will be less than the developer's costs - $287,225 for water assets and $2,147,500 for the sewer assets. This imbalance will be treated as CIAC and will reduce Aqua NC's rate base. The Commission rejects PSS' arguments because they impermissibly pick and choose among the pertinent facts and provide an incomplete and inaccurate picture.

PSS cites Section 17C of the Uniform System of Accounts as authority in support of its plant acquisition adjustment argument. The Commission determines that PSS' reliance on this authority is misplaced. Section 17C addresses the transfer of public utility assets from a public utility seller to a public utility buyer. The transfer of water and sewer assets from the Park South Station developer to Aqua NC does not qualify. The developer is not a public utility. The assets in the hands of the developer were never dedicated to the public service. The developer has never held a Certificate of Public Convenience and Necessity (CPCN). The assets in the hands of the developer were never used to provide public utility service. The Commission has never exercised jurisdiction over the developer and its books need not be and have not been kept in accordance with the Uniform System of Accounts.

With respect to connection fees, at the time a Park South Station residence is brought on line, Aqua NC pays the developer $1,200 and simultaneously collects $700 to offset the costs of connection-meter activation, billing, and computer entries, etc. As with the other contributions Aqua NC receives, these connection fees are booked as CIAC and offset against rate base. At full build-out, Aqua NC's documentation indicates that it will have positive rate base in Park South Station.

Even if Aqua NC's investment in the Park South Station assets were exceeded by contributions or some plant acquisition adjustment were appropriate, were the rates for Park South Station established on a system-specific basis, it is the Commission's longstanding practice to authorize utilities to earn an element of profit even where no investment can be established. PSS witness Novak inappropriately would allow no profit in the rates he advocates for Park South Station on a standalone basis.

For the aforementioned reasons, the Commission finds and concludes that the customers in the Park South Station service area should be charged the standard base facility fee that Aqua NC charges the majority of its customers for water and sewer services. Further, the Commission rejects PSS' contention that Aqua NC should have no rate base for its system in Park South Station.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 22

The evidence supporting this finding of fact is contained in the testimony of Public Staff witness Furr and Aqua NC witness Roberts.

WATER AND SEWER – RATE INCREASE

The Public Staff contended that there is excess capacity in four of Aqua NC's sewer systems: Chapel Ridge, Country Woods East, The Legacy at Jordan Lake, and Carolina Meadows. Aqua NC does not dispute the proposed adjustment as to Carolina Meadows, and this is reflected in Finding of Fact No. 15 of their Proposed Order. Aqua NC does, however, contend that it is appropriate for it to earn a return on their investment in the Chapel Ridge, Country Woods East, and The Legacy at Jordan Lake systems. Witness Roberts testified that the Chapel Ridge, Country Woods East, and The Legacy at Jordan Lake systems were either included in prior rate cases (Country Woods East and Chapel Ridge) or the rate base was previously approved by the Commission as part of the issuance of the franchise (The Legacy at Jordan Lake).

The Commission has effectively found in past rate cases involving Country Woods East and Chapel Ridge that Aqua NC's investment in those systems was used and useful. The Public Staff's effort to now "look back" and revise its position on that issue, based on a change in economic conditions or other such factors, is inappropriate. Commission orders granting certificates of public convenience and necessity or recognizing contiguous extensions typically do not contain language pre-approving levels of rate base; however, they may approve connection fees and other miscellaneous fees considered part of the tariff. The certificate Order for The Legacy at Jordan Lake did not provide approval of rate base. Based upon the foregoing, the Commission finds and concludes that it should not make an excess capacity adjustment for Country Woods East and Chapel Ridge, but should make an excess capacity adjustment for Carolina Meadows and The Legacy at Jordan Lake.

The Public Staff made an adjustment to reduce rate base by $2,453,551 to remove the percentage of plant, CIAC, accumulated depreciation, and accumulated amortization related to excess capacity for the following four wastewater treatment plants (WWTPs):

WWTP	Plant, Net of Accum. Depr. and CIAC	Excess Capacity Percent	Excess Capacity Adjustment
Carolina Meadows	$3,742,392	43.65%	$1,633,554
Chapel Ridge	459,404	94.38%	433,585
Country Woods East	270,700	47.10%	127,500
The Legacy at Jordan Lake	265,442	97.54%	258,912
Total excess capacity adjustment			$2,453,551

Public Staff witness Furr testified that he calculated the percent of excess capacity for each wastewater treatment facility as follows: Percent Excess Capacity = 100 - ((high average monthly flow ÷ 90% of plant capacity installed) x 100)

Witness Furr testified that the high average-monthly flow for each facility was obtained from the test-year monthly-monitoring reports filed by Aqua NC with the North Carolina Department of Environment and Natural Resources (DENR). He testified that he chose 90% of plant capacity since it is not practical to operate at full capacity and satisfy regulatory flow requirements. Further, witness Furr asserted that the results of his calculations as shown in Furr Exhibit 2 are as follows:

WWTP	Installed Capacity (gals./day)	90% of Installed (gals./day)	End of Period REUs	High Monthly Ave. Flow (gals./day)
Carolina Meadows	350,000	315,000	596	177,500
Chapel Ridge	500,000	450,000	162	25,304
Country Woods East	670,000	603,000	1,273	319,000
Legacy at Jordan Lake	120,000	108,000	17	2,655

Witness Furr asserted on redirect that the excess capacity formula the Public Staff used in this Aqua NC rate case was less stringent for Aqua NC than some prior Commission decisions on WWTP excess capacity, as the Public Staff used (1) the highest monthly flow rather than the DENR 12-month average, and (2) 90% of the installed capacity rather than 100%.

During cross-examination, witness Furr stated that his adjustments were based on the ratemaking practice of matching plant in service to revenues, and that it is not appropriate in a rate case proceeding for existing customers to carry the financial burden for investment that has been made to serve future customers. He contended that Aqua NC witness Roberts had acknowledged the theory and practice by the fact that he had agreed with the Carolina Meadows WWTP excess capacity adjustment.

The Commission takes issue with the Public Staff's methodology of determining used and useful plant and thus computing an excess capacity adjustment. In the present case, witness Furr computes the used and useful portion of a WWTP by dividing the highest monthly-average flow by 90% of the installed capacity of the plant (with the remainder being the excess capacity). Witness Furr asserted that this methodology was less stringent for the Company than some prior Commission decisions on WWTP excess capacity.

In particular, in his testimony filed in January 2009 in Docket No. W-218, Sub 274, witness Furr computed an excess capacity factor of 40.90% for the Carolina Meadows wastewater treatment plant utilizing a maximum daily flow of 207,000 gpd (peak monthly-average flow was 157,000 gpd). However, in the current case, witness Furr computes an excess capacity factor of 43.65% for the Carolina Meadows WWTP utilizing a high monthly-average flow of 177,500 gpd. It defies logic that, with more flow now than two years ago, the excess capacity (the portion of the plant not used and useful) of the plant has increased. This methodology is not less stringent.

The Commission takes issue with both Public Staff methods (Sub 274 and Sub 319) of computing used and useful plant utilizing maximum-daily flow or highest monthly-average flow. Long ago the Commission concluded that the standard for evaluating the used and useful portion of WWTPs should be 400 gpd per connection. (See Commission Order issued June 10, 1994, in Docket No. W-354, Sub 128.) DENR standards require that a treatment plant design must meet a minimum flow (400 gpd) capacity per connection providing flow into the plant. The plant owner does not have the option to build a plant based on the level of usage that <u>may</u> be experienced in the future (the design of a plant expansion may be based on historic operational experience, if approved by DENR).

While it is appropriate to disallow a portion of the plant rate base because a plant designed for 875 REUs has only 596 REUs connected, it is not appropriate to disallow a larger portion of the plant rate base because the 596 REUs do not happen to produce the flow (596 x 400 gpd = 238,400 gpd) that DENR required the plant to be able to handle.

The Commission considers that there is a fundamental flaw in utilizing the actual flow (whether it is maximum-daily flow, maximum monthly-average flow, annual-average flow, etc.) in the plant to compute a used and useful percentage of the plant. At different times (different rate cases for instance), the same number of REUs could produce different flows to the plant. At one time, the service area may be populated by families with several older children producing a high volume of water usage per REU and at a later time, the families may have matured with children having left home, leaving behind a service area populated with empty nesters with a lower volume of water usage per REU. In this example, if the actual flow to the plant is used to compute used and useful plant, there would be a larger excess capacity adjustment in the latter rate case for the identical number of REUs connected to the plant. The Commission does not believe it would be appropriate to find that the plant is less used and useful because the demographics of the households changed over time (nor would it be appropriate to find the plant to be more used and useful if the flow increased over time without the number of REUs connected increasing).

The Commission finds and concludes that the determination of excess capacity should be based upon the number of end-of-period REUs. The following table presents a combination of the two tables hereinabove which indicate the Public Staff's position (after deleting Chapel Ridge and Country Woods East) and expanding it to show the Commission's computations, i.e., the table below shows the Commission's excess capacity adjustment versus the Public Staff's excess capacity adjustment:

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Wastewater Facility	Installed Capacity (gpd)	90% of Installed Capacity (gpd)	EOP REUs	High Monthly Avg Flow (gpd)	PS Excess Capacity Percentage (1 - e/c)	EOP x 400 gpd	Comm. Excess Capacity Percentage (1 - g/b)	Plant, Net of Accum Depr & CIAC	PS Excess Cap. Adjustment (i x f)	Comm Excess Cap. Adjustment (i x h)
Carolina Meadows	350,000	315,000	596	177,500	43.65%	238,400	31.89%	$3,742,392	$1,633,554	$1,193,449
Legacy at Jordon Lake	120,000	108,000	17	2,655	97.54%	6,800	94.33%	$265,442	$258,912	$250,391
Total	Excess	Capacity	Adj.							$1,443,840

In the past the Commission has employed a variety of formulas and methods for making excess capacity adjustments. In this case the only one proposed is the one advocated by Public Staff witness Furr. For reasons stated herein the Commission has used a different calculation. Unfortunately Aqua NC presented no evidence as to what, in its view, a reasonable method for making an excess capacity adjustment should be. Should this issue arise in future cases, the Commission could benefit from more evidence from Aqua NC on this point.

Accordingly, the Commission finds and concludes that the appropriate excess capacity adjustments are $1,193,449 for the Carolina Meadows WWTP and $250,391 for The Legacy at Jordan Lake WWTP.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 23 THROUGH 29

The evidence supporting these findings of fact is contained in the testimony of Public Staff witnesses Fernald and Furr and Company witnesses Becker and Roberts. The following table summarizes the differences between the Company's level of rate base from its application and the amounts recommended by the Public Staff:

Item	Company Application	Public Staff	Difference
Plant in service	$344,527,827	$346,636,347	$ 2,108,520
Accumulated depreciation	(107,939,581)	(108,491,025)	(551,444)
Contributions in aid of const.	(148,449,133)	(154,388,727)	(5,939,594)
Accum. amortization of CIAC	41,142,624	42,384,789	1,242,165
Acquisition adjustments	2,274,945	1,863,960	(410,985)
Accum. amort. of acquis. adj.	2,043,969	1,917,198	(126,771)
Advances for construction	(4,207,554)	(4,418,554)	(211,000)
Net plant in service	129,393,097	125,503,988	(3,889,109)
Customer deposits	(384,873)	(384,873)	0
Unclaimed refunds	(193,293)	(193,293)	0
Accum. deferred income taxes	(3,456,145)	(7,567,256)	(4,111,111)
Materials and supplies inventory	1,088,109	1,088,109	0
Excess capacity adjustment	0	(2,453,551)	(2,453,551)
Working capital allowance	3,396,301	2,288,007	(1,108,294)
Original cost rate base	$129,843,196	$118,281,131	($11,562,065)

As a result of the Stipulation between Aqua NC and the Public Staff entered and filed on June 30, 2011; the revisions made by the Public Staff in its supplemental testimony filed on June 7, 2011; and the revisions reflected by the Public Staff in Revised Fernald Exhibit I filed on June 30, 2011, the Company does not dispute the following Public Staff adjustments to rate base:

Item	Amount
Adjust post test-year additions	($6,816,469)
Remove plant costs related to future customers	(187,696)
Remove project not yet in service	(102,871)
Capitalize legal fees for Northgate well	17,886
Capitalize legal fees for Setzer acquisition	2,275
Include documented plant items	36,552
Correct Company error in Rayco accumulated depreciation	(95,082)
Reflect post test-year retirements in accumulated depreciation	3,218,733
Include acquired accumulated depreciation	(134,269)
Adjust acquisition incentive adjustments	(197,670)
Include negative acquisition adjustment for Emerald Plantation	(315,886)

Include ADIT on non-depreciation items	295,289
Update rate base to December 31, 2010	(2,619,918)
Correct Company error in Brookwood unamortized tank painting	(341,898)
Remove other prepayments from working capital	(210,758)
Adjust gains / (losses) on vehicles and equipment	(89,955)
Adjust amortization period for rate case expense	(48,652)
Remove Windsor Oaks	(222,756)
Remove systems to be sold	(926,206)
Total	($8,739,351)

Therefore, the Commission finds and concludes that the adjustments listed above, which are not contested, are appropriate adjustments to be made to rate base in this proceeding.

Through the testimony of Company witnesses Becker and Roberts, the Company disagreed with the following Public Staff adjustments to rate base:

Item	Amount
Remove excess capacity for four treatment plants	($2,453,551)
Adjust cash working capital	(307,932)
Adjust average tax accruals	(61,231)
Total	($2,822,714)

Further, the Company contended in its Proposed Order that the ADIT balances included in Fernald Exhibit I, Schedule 2-6 REVISED, filed on June 30, 2011, have not been adjusted to account for the impact of the ADIT related to the CMU transfer or the Windsor Oaks abandonment. Aqua NC maintained that an amount of $166,848 related to the transfer of the seven systems to CMU should be added back to rate base, thereby increasing the total amount of rate base included in this proceeding.

Also, PSS, the intervener in this case, has raised an issue concerning the treatment of rate base for the Park South Station system which is addressed in the evidence and conclusions for Findings of Fact Nos. 13 through 21 hereinabove.

The disputed excess sewer capacity issue is addressed in the evidence and conclusions for Finding of Fact No. 22 hereinabove.

Working Capital Allowance

The difference in the working capital allowance is due to the differences in cash working capital and average tax accruals, which are a result of differences in the levels of expenses and certain taxes. Based on conclusions regarding the appropriate levels of expenses and certain taxes reached elsewhere in this Order, including the corresponding adjustments to the total amount of expense to be removed from this proceeding related to the 21 customers on the two

Virginia water systems[1], the Commission concludes that the appropriate level of cash working capital and average tax accruals for use in this proceeding are $2,805,359 and $650,526, respectively. Based on these amounts and the level of deferred charges of $272,924 agreed to by the parties, including an update to unamortized rate case expense, as reflected in the Public Staff's August 24, 2011 filing, the appropriate level of working capital allowance for use in this proceeding is $2,427,757 ($2,805,359 minus $650,526 plus $272,924).

ADIT

In accordance with Provision 8 of the June 30, 2011 Joint Stipulation filed in this proceeding by the Public Staff and Aqua NC, the rates approved by the Commission by its Notice of Decision issued on September 13, 2011 are provisional rates, subject to adjustment to reflect the Commission's rulings in Docket W-218, Sub 325 concerning (1) the treatment of any gain on sale; (2) the treatment of the loss for Windsor Oaks; (3) the revenues, expenses, and rate base associated with Windsor Oaks and the systems being sold to CMU; and (4) any other rulings by the Commission in the transfer proceeding which affect Aqua NC's rates. Consequently, the Commission finds and concludes that the provisional rates currently in effect should be adjusted to reflect any necessary adjustments to ADIT associated with the transfer of the seven systems to CMU and that such adjustments will be reflected in the Commission's rulings in Docket No. W-218, Sub 325.

Summary

Based on the foregoing and the findings and conclusions hereinabove regarding the sewer excess capacity adjustment, the Park South Station matters, and the ADIT related to the impact of the transfer of the seven systems to CMU or the Windsor Oaks abandonment, the Commission concludes that the appropriate level of rate base for combined operations for use in this proceeding is as follows:

Item	Amount
Plant in service	$346,636,347
Accumulated depreciation	(108,491,025)
Contributions in aid of const.	(154,388,727)
Accum. amortization of CIAC	42,384,789
Acquisition adjustments	1,863,960
Accum. amort. of acquis. adj.	1,917,198
Advances for construction	(4,418,554)
Net plant in service	125,503,988
Customer deposits	(384,873)
Unclaimed refunds & cost-free capital	(193,293)

[1] In this proceeding, the Company removed the rate base and revenue associated with two small water systems that it operates in Virginia, but the Company failed to remove the expenses for these systems. Consequently, the Public Staff made adjustments to remove $5,710 in expenses that would be associated with the Company's service to the 21 customers on these two Virginia systems. Those adjustments are in some instances directly impacted by a determination of certain items of expense in dispute, but the methodology used in computing the fallout amount for the related Virginia system adjustments is not contested by the Company.

Accum. deferred income taxes	(7,610,422)
Materials and supplies inventory	1,088,109
Excess capacity adjustment	(1,443,840)
Working capital allowance	2,427,757
Original cost rate base	$119,387,426

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 30

The evidence supporting this finding of fact is contained in the testimony of Public Staff witnesses Fernald and Tweed and Company witnesses Becker and Roberts.

This issue involves the Company's inclusion of commissions paid by the Company to USC for services provided regarding the leasing of antenna space on the Company's elevated water tanks. Pursuant to a data request dated May 16, 2011, the Company provided the Public Staff with a copy of the Wireless Communications Management Agreement executed between the Company and USC (USC Agreement), along with four individual leases for antenna space that USC had obtained for the Company.

Public Staff witness Fernald testified that prior to 2007 the Company handled the negotiation, management, and billing and collection for antenna lease agreements and that handling such matters in-house was typical operating practice for regulated water utilities in North Carolina. Witness Fernald asserted that the Company has a responsibility to provide adequate service at reasonable rates and that the Company should control costs to ratepayers or seek additional revenues whenever possible.

Witness Fernald stated that on February 7, 2007 a former regional manager of the Company executed the USC Agreement that gave USC the exclusive authority to enter into multi-year license agreements for the use of antenna mounting and equipment-shelter space on 19 Aqua NC water tanks. The USC Agreement includes an initial term of 10 years; and at the expiration of the initial term it will be automatically renewed for the remaining term of any antenna license agreements.

Witness Fernald observed that the USC Agreement provides that USC may cancel the agreement at any time after 180 days written notice to Aqua NC. However, the USC Agreement provides that Aqua NC can only cancel the agreement if USC materially violates the terms of the agreement. The USC Agreement provides USC 30 days to cure any default after written notice from Aqua NC.

Witness Fernald explained that under the USC Agreement, USC retains a 30% commission as compensation for its services. Further, witness Fernald testified that since February 7, 2007 USC has entered into four antenna leases that are covered by the USC Agreement. Three of the leases have an initial term of five years, which will automatically renew for four additional terms of five years each. The fourth lease has an initial term of five years, which will automatically renew for three additional terms of five years each. The annual level of revenues derived from these four leases is currently $93,564, of which 30% or $28,069 is paid to USC as commission.

WATER AND SEWER – RATE INCREASE

Witness Fernald asserted that the Company has the burden of proof to show that costs are reasonable and prudent, and this burden includes proving the prudence and reasonableness of any agreements entered into by the utility with third parties. Witness Fernald observed that she requested that the Company provide the cost/benefit analysis which the Company performed in reaching its decision to enter into the USC Agreement, but the Company responded that no cost/benefit analysis was available. According to witness Fernald, the Company has been unable to provide any documentation to support the reasonableness of the commission amount and has not provided any due diligence that was conducted prior to entering into the agreement or any cost/benefit analysis or any breakdown as to what services are actually being provided by USC that would support the 30% level of commissions. Witness Fernald stated that she is not aware of any other regulated water or sewer utility that pays a 30% commission on antenna lease revenue.

Further, witness Fernald testified that prior to the execution of the USC Agreement on February 7, 2007 the Company had 25 pre-existing and current antenna leases that were executed without USC's contracted assistance and without USC's 30% commission. The total annual rent on the 25 pre-existing antenna leases totals $670,866, with a current average annual rent of $26,835 compared to the current average annual rent of the four USC negotiated antenna leases of $23,391. Witness Fernald contended that if each of these four antenna leases under the USC Agreement extends to their full terms of three leases at 25 years and one lease at 20 years then the total commissions paid to USC for these four leases would exceed $675,000. Witness Fernald expressed the Public Staff's concern that the Company could not document the benefit of its 2007 decision to enter into a long-term exclusive agreement with an outside party that compensates the outside party at such a high rate (30%), while limiting the ability of the Company to evaluate and implement other options for the services provided. Witness Fernald testified under cross-examination that her audit did not note any material annual costs related to the antenna leases that would support a 30% annual commission.

Additionally, witness Fernald testified that the annual number of antenna lease agreements signed has decreased since the USC Agreement took effect. In the three years prior to the 2007 agreement, nine lease agreements were signed. In the four years after the 2007 agreement, a total of four lease agreements have been signed.

Witness Fernald recommended removing the antenna lease commissions paid to USC from miscellaneous revenues, which would result in an increase in miscellaneous revenues of $28,069. Witness Fernald maintained that the Company has not met its burden of proof that the agreement entered into with USC was prudent, and that the commissions paid to USC pursuant to the USC Agreement are reasonable.

In rebuttal testimony, Company witness Roberts testified that in 2007 Aqua NC entered into a contract with USC for the management of antenna leases on certain of the Company's elevated tanks. USC is in the business of providing various services, including marketing antenna sites, preparation of license agreements, antenna installation inspection and ongoing management of the antenna sites under contract. First, witness Roberts explained that the contract was needed because employees of Aqua NC did not have the expertise required to design, install, maintain, or otherwise manage the installation of antennas on elevated water storage tanks. Second, if antennas are installed improperly on an elevated tank, harm could result to both the structure and the coating of the tank. Ultimately, such a scenario would result in additional expense that ratepayers may have to bear. Third, when this contract was entered into, USC worked with Aqua NC to "clean up" a number of existing antennae installations on Aqua NC tanks. In addition, USC negotiated with cellular companies with existing antenna installations to pay for the retrofit of their prior substandard installations.

Witness Roberts asserted that all of this was to the benefit of the Company's ratepayers, either in terms of generating additional revenue to offset the Company's revenue requirement, or in avoiding operating expense that would otherwise flow through to ratepayers. The Company considers it only logical to have a vendor with expertise to represent the owner in these circumstances.

Further, witness Roberts opined that while antenna lease revenues have no direct benefit for Aqua NC, revenue from antenna leases does benefit Aqua NC's customers by acting as revenue offsets when calculating Aqua NC's revenue requirement. Witness Roberts also testified that there is no requirement that Aqua NC maintain or solicit revenue such as antenna leases. Witness Roberts argued that the Company is a water and sewer provider which closely monitors its labor expense and that there are benefits to delegating the antenna leasing operation to specialists in the field, in that it is not a part of Aqua NC's core business expertise.

Finally, witness Roberts testified that USC provides various services, including preparation of license agreements, antenna installation inspection, and ongoing management of sites under contract; but he also acknowledged that the Company was unable to locate any detailed or specific cost/benefit analysis for the delegation of the leases, though he felt the absence of such documentation was not relevant to the issue of the prudence in the execution of the USC Agreement and that the USC Agreement was a reasonable business decision.

After carefully considering the evidence and the arguments of the Company and the Public Staff, the Commission agrees with the Company that there is no requirement for Aqua NC to enter into an antenna lease for elevated tanks and there is no requirement to have a formal, detailed cost/benefit analysis to justify such a management decision. Moreover, the Commission concludes that under the prevailing facts and circumstances of this case, the Company has, in fact, acted reasonably and prudently in order to reduce costs for its customers by contracting with USC and thereby securing additional antenna site lease agreements.

More specifically, the Commission finds that Company's actions related to generation of non-regulated income through antenna leases are reasonable. This sort of management decision concerning whether the Company should secure professional management for some of its antenna contracts is the sort of operational business decision that is appropriately left to Company management.

Further, the Commission finds that Aqua NC acted prudently, first, in seeking out a revenue source it is not required to seek out and, second, in generating a significant offset to its revenue requirement, which directly benefits its ratepayers. The commissions paid to USC for securing and managing these antenna site leases are expenses actually incurred by the Company, and these expenses properly reduce the Company's miscellaneous revenues. The Commission thus concludes that 100% of the commissions paid by the Company to USC are recoverable and therefore should offset related revenues. Accordingly, the $28,069 of commission expense should be included as a reduction in the Company's miscellaneous revenues in this proceeding.

Although the Commission has determined that the actions undertaken by the Company with regard to these leases are prudent and reasonable, that the Commissions paid by the Company to USC are recoverable, and that the Commission is not persuaded by the evidence presented in this proceeding that the Public Staff's contentions to the contrary should be adopted, the Commission would nevertheless urge the Company to pay particular attention to the substance of the Public Staff's contentions and govern its future actions in these matters accordingly. More particularly, in future cases the Company should provide more detailed evidence of comparable costs associated with third-party contracts for the management of antennae leases on water tanks, that the overall terms of the contract are reasonable and prudent, that the cost of the service being purchased is comparable to amounts incurred by other regulated companies for similar services, and that the payment to the third-party vendor is a reasonable compensation based on the services provided by that party. In the Commission's opinion, these actions, although not required under the particular facts of this case, would greatly assist the Commission in future cases as it examines expenses incurred by the Company relating to antenna leases to determine if said expenses were reasonable and prudently incurred under the facts in a subsequent proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 31

The evidence supporting this finding of fact is contained in the testimony of Company witnesses Becker and Roberts and Public Staff witnesses Fernald and Tweed.

In its Proposed Order, Aqua NC agreed with the Public Staff that the Company's present rates for water and sewer utility service produce the following revenues:

Aqua Water	$27,268,704
Aqua Sewer	9,582,238
Fairways Water	752,240
Fairways Sewer	980,666
Brookwood Water	4,650,859
Total Combined Operations	$43,234,707

Based on these amounts of present service revenues, witness Fernald calculated an amount for late payment fees of $114,453 for the Company's combined operations under present rates. Witness Fernald proposed that the late payment fee percentages for each of the rate entities be adjusted to reflect the per books levels of late payment fees and service revenues for calendar year 2010 and she applied the resulting percentages[1] to the present service revenue

[1] The late payment fee percentages applicable for each rate entity are as follows: Aqua water – 0.26%; Aqua sewer – 0.21%; Fairways water – 0.28%; Fairways sewer – 0.23%; and Brookwood water – 0.41%.

amounts indicated above. Likewise, witness Fernald calculated the uncollectible percentages[1] for each of the rate entities and recommended a level of uncollectibles of $325,563 for the Company's combined operations under present rates. The Company agreed with the Public Staff's calculations for determining late payment fees and uncollectibles.

The only area of disagreement between the Public Staff and the Company regarding the proper level of total operating revenues for Aqua NC's combined operations under present rates is in regard to the Public Staff's proposed disallowance of the expenses incurred by Aqua NC in paying commissions due USC in connection with antenna leases secured by that firm. That adjustment, in the amount of $28,069, has been previously addressed in the evidence and conclusions for Finding of Fact No. 30. The Commission concluded that those expenses should be treated as a reduction to miscellaneous revenues.

Based upon the foregoing, the Commission finds and concludes that the appropriate level of total operating revenues for Aqua NC's combined operations under present rates for use in this proceeding is $44,346,303, consisting of service revenues of $43,234,707; late payment fees of $114,453; and miscellaneous revenues of $1,322,706; reduced by uncollectibles of $325,563.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 32

The evidence supporting this finding of fact regarding Aqua NC's requested increase in revenues that would be produced by its proposed water and sewer utility rates is found in the Company's Application filed in this docket and in the Company's Proposed Order, wherein the Company presented its revised requested increase in additional service revenues.

Aqua NC initially requested an increase in its water and sewer utility rates that would produce total additional service revenues of $8,216,073, as follows:

	Company Initial Request
Aqua Water	$5,399,940
Aqua Sewer	1,631,652
Fairways Water	306,480
Fairways Sewer	120,161
Brookwood Water	757,840
Total Combined Operations	$8,216,073[2]

In its Proposed Order, Aqua NC observed that it had accepted many of the Public Staff's proposed adjustments. Consequently, the Company revised its initial request to a lower amount. The Company explained that it had accepted as a starting point the increased revenue amounts

[1] The uncollectible percentages applicable for each rate entity are as follows: Aqua water – 0.68%; Aqua sewer – 0.65%; Fairways water – 0.52%; Fairways sewer – 0.76%; and Brookwood water – 1.41%.

[2] The individual amounts of service (sales) revenues for the above rate entities were provided in the Company's application under each rate entity's respective profit and loss summary statement in Exhibit Dw (for water) and Exhibit Ds (for sewer).

set forth in Fernald Exhibit 1, Schedule 3 Revised and then made modifications thereto for the Company's adjustments relating to issues still in dispute (as discussed and resolved elsewhere in this Order) to determine its revised requested increase in additional service revenues. In its Proposed Order, Aqua NC revised its request to produce the following total additional service revenues:

	Company Revised Request
Aqua Water	$3,221,125
Aqua Sewer	658,258
Fairways Water	226,534
Fairways Sewer	118,400
Brookwood Water	267,125
Total Combined Operations	$4,491,442

Aqua NC stated that its resulting recommended revenue increase is a culmination of the Public Staff's final proposed accounting adjustments, plus the Company's proposed revisions to those adjustments to reflect the resolution of the disputed issues. Further, Aqua NC observed that as a matter of accounting reality, every change to expense and/or rate base flows through to affect the final revenue increase amount necessary to meet the Company's revenue requirement.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 33 THROUGH 44

The evidence supporting these findings of fact is contained in the testimony of Company witnesses Becker and Roberts and Public Staff witnesses Fernald, Furr, and Tweed. The following table summarizes the differences between the Company's level of operating and maintenance (O&M) and general and administrative (G&A) expenses for its combined operations, as presented in its application, and the amounts recommended by the Public Staff:

Item	Company Application	Public Staff	Difference
Salaries and wages	$ 8,375,266	$ 7,798,626	$ (576,640)
Employee benefits	2,260,746	1,856,811	(403,935)
Purchased water / sewer	1,359,089	1,369,036	9,947
Sludge removal	450,969	427,572	(23,397)
Purchased power	2,947,301	2,888,587	(58,714)
Fuel for power production	10,067	10,067	0
Chemicals	1,292,675	1,126,469	(166,206)
Materials and supplies	300,827	269,109	(31,718)
Testing fees	980,686	980,686	0
Transportation	1,599,995	1,460,236	(139,759)
Contractual services–engineering	5,761	5,761	0
Contractual services – accounting	119,172	105,828	(13,344)
Contractual services – legal	160,033	52,021	(108,012)
Contractual services – management fees	86,317	86,317	0
Contractual services – other	3,006,984	2,736,595	(270,389)

Rent	589,987	573,998	(15,989)
Insurance	768,443	579,620	(188,823)
Regulatory commission expense	204,696	139,131	(65,565)
Miscellaneous expense	1,479,053	1,422,005	(57,048)
Interest on customer deposits	23,979	23,979	0
Annualization & consumption adjustments	0	80,293	80,293
Other Public Staff adjustments	0	(424,224)	(424,224)
Total O&M and G&A expenses	$26,022,046	$23,568,523	($2,453,523)

In consideration of the Joint Stipulation between the Company and the Public Staff and the Company's acceptance of many of the Public Staff's adjustments as reflected in its Proposed Order and in the revisions made by the Public Staff in its supplemental testimony and in Revised Fernald Exhibit I, the Company does not dispute the following Public Staff adjustments to O&M and G&A expenses:

Item	Amount
Update expenses to December 31, 2010	$ 111,911
Adjust gains / (losses) on vehicles & equipment	7,204
Adjust amortization period for rate case expense	(65,565)
Reflect Company update to salaries and benefits	(217,015)
Reflect new hires and terminations since 5/26/11	26,434
Remove open positions	(94,826)
Adjust percentage charged to expense by NC employee	(26,079)
Adjust stock option expense for NC employees	(9,410)
Adjust restricted stock expense for NC employees	(15,638)
Remove time spent on acquisitions by corporate	(10,156)
Adjust ACO (Aqua Customer Operations) allocation factor	(58,916)
Reflect changes in ACO employees since 7/31/10	4,900
Reflect employee contributions for dental benefits	(20,632)
Adjust NC pension expense	2,996
Adjust corporate pension expense	(28,711)
Adjust sludge removal	(23,397)
Adjust purchased power	(58,714)
Adjust chemicals	(166,206)
Remove Company adjustment to materials & supplies	(31,718)
Adjust testing fees	0
Reflect Company update to transportation fuel cost	23,558
Adjust transportation lease expense	3,874
Adjust audit fees	(13,344)
Adjust corporate legal fees	(23,245)
Adjust NC legal fees	(84,767)
Remove Company adjustment to ACO direct costs	(72,154)
Adjust water filter backwash hauling	9,021
Adjust collection maintenance hauling	26,708
Adjust right of way clearing	(43,400)
Remove nonrecurring rent expense	(9,753)

Adjust insurance premiums	(50,008)
Remove Company adjustment to permits & licenses	(49,813)
Remove Company adjustment to travel & entertainment	(6,919)
Include Olde Beau annual fees	2,750
Adjust corporate allocation factors	(25,727)
Remove expenses for Virginia systems	(5,710)
Remove Windsor Oaks	(56,668)
Remove systems to be sold	(357,790)
Total	($1,406,925)

Therefore, the Commission finds and concludes that the adjustments listed above, which are not contested, are appropriate adjustments to be made to O&M and G&A expenses in this proceeding.

The Company disagreed with the following Public Staff adjustments to O&M and G&A expenses, as evidenced by the testimony of Company witnesses Becker and Roberts and as, summarily, argued in the Company's Proposed Order:

Item	Amount
Salaries and Benefits:	
Reflect hours worked for 12 months ended 3/31/11 (capitalization %age)	$ (208,455)[1]
Remove time spent on nonutility work & acquisitions	(89,794)[2]
Adjust corporate executive compensation	(160,211)[3]
Adjust medical/dental benefits for additional employees	(92,440)
Transportation Expense:	
Reflect three-year average gasoline prices	(169,756)
Contractual Services – Other:	
Adjust water filter backwash hauling – Chesapeake Point	(30,024)
Adjust sewer jetting	(157,103)
Insurance Expense:	
Adjust claims to three-year average of claims paid	(138,815)
Total	($1,046,598)

These contested expense adjustments affect salaries and benefits, rent expense, transportation expense, contractual services – other, and insurance expense.

[1] This amount is composed of the following adjustments: ($132,904) salaries + ($70,912) benefits + ($4,639) transportation = ($208,455).

[2] This amount is composed of the following adjustments: ($71,491) salaries + ($18,303) benefits = ($89,794).

[3] This amount is composed of the following adjustments: ($130,737) salaries + ($26,143) benefits + ($3,331) rent = ($160,211).

WATER AND SEWER – RATE INCREASE

Salaries and Benefits

As reflected in the prefiled testimony of Public Staff witness Fernald and the rebuttal testimony of Aqua NC witness Becker, the Public Staff and the Company initially disagreed on the total number of employees that should be used to calculate salaries and wages for use in this proceeding. However, during cross-examination at the hearing, witness Fernald testified that if the Company would provide the actual documentation for the current number of employees, she would review that information for reasonableness and make those adjustments. On June 30, 2011, the Public Staff filed final schedules, which included an adjustment to increase salaries and wages by $26,434 to reflect the new hires and terminations since the date the Public Staff prefiled its testimony based on the actual documentation provided by the Company after the hearing. In its cover letter filed with the June 30, 2011 final schedules, the Public Staff stated that its recommended level of salaries and wages included the actual salaries and wages for the 168 employees as of the hearing date and excluded the salaries and wages related to the three open positions as of that same date.

In its Proposed Order, Aqua NC stated that the salaries and wages included in the Public Staff's June 30, 2011 filing were consistent with the Company's authorized employee headcount of 171 employees at full employment and its historical average of approximately three vacant positions. Consequently, the Public Staff and the Company have agreed that it is appropriate to calculate Aqua NC's salaries and wages based upon the actual number of employees of 168, as of the hearing date.

The Commission finds and concludes that the Public Staff's June 30, 2011 final adjustment to salaries and wages, which is not contested by the Company, is appropriate; accordingly, the level of salaries and wages for use in this proceeding should be based upon the actual number of employees of 168 (authorized head count of 171 minus 3 open positions), as of the hearing date.

The Public Staff and the Company disagreed on the following items concerning salaries and benefits: (1) capitalization percentage, (2) time spent on nonutility work and acquisitions, (3) executive compensation, and (4) medical benefits for new employees.

(1) Capitalization Percentage

Aqua NC witness Becker testified that the appropriate labor capitalization percentage for use in this proceeding is 21.62%. Witness Becker explained that such rate would be applied to the Company's various overhead expenses to determine what portion of each such cost is allocated to capital and what portion is allocated to expense. Witness Becker further explained that the application of such capitalization percentage affects the amount of recoverable expenses in this proceeding related to the areas of labor, benefits, transportation expense, some components of insurance expense, and payroll taxes.

Witness Becker testified that Aqua NC expected, and has realized, a shift to a reduced labor capitalization rate as a result of a less capital intensive environment due to fewer large capital projects and a focus on maintenance. Since this trend is more recent, witness Becker contended that using the most recent payroll activity to identify the pattern of the decrease in Aqua NC's labor capitalization rate is more appropriate than using a historical 12-month period as proposed by the Public Staff. Witness Becker asserted that the Public Staff's use of a straight trailing 12-month analysis of labor capitalization rate activity ignores the majority of the expected decrease in the capitalization rate, as only one quarter of this expected decline is incorporated in the Public Staff's calculation.

In his rebuttal testimony, witness Becker submitted that a comparison of the labor capitalization rate for the first two quarters of 2011 compared to 2010 demonstrates this shift. According to witness Becker, when comparing the first two quarters of 2010 to 2011, there is a 272 basis-point reduction from 25.63% for the first two quarters of 2010 to 22.91% for the first two quarters of 2011.. At the evidentiary hearing, witness Becker clarified that the data he used for the first two quarters of 2011 was for the five months ended May 31, 2011. Witness Becker explained that application of the 272 basis-point reduction to the test-year labor capitalization rate of 24.34% results in the Company's proposed labor capitalization rate of 21.62% (24.34% - 2.72%) to be used in this proceeding.

In contrast, Public Staff witness Fernald testified that the Company's overall capitalization percentage is 24.51% based upon the 12 months of historical data ended March 31, 2011. With respect to the labor capitalization percentage, witness Fernald observed that in the Company's update for salaries provided to the Public Staff, the Company had adjusted the overtime hours and capitalization percentages used to calculate salaries to reflect the amounts for the three months ended March 31, 2011, annualized. Witness Fernald explained that it is inappropriate to annualize only three months of this type of data when a longer period of historical information is available because doing so fails to recognize the difference between the winter months and summer months which could affect the level and type of hours worked. Witness Fernald asserted that the Company's use of amounts for the three months ended March 31, 2011, annualized, resulted in an overall capitalization percentage of 20.98% and total overtime hours of 18,036; whereas, the Public Staff's use of the historical amounts for the 12 months ended March 31, 2011, resulted in an overall capitalization percentage of 24.51% and overtime hours of 19,157.

In her revised schedules filed on June 30, 2011, as result of updated information provided by the Company, witness Fernald updated the Public Staff's calculation of the Company's overall capitalization percentage from 24.51% to 24.63%, and updated the Public Staff's calculation of the Company's salaries to nonutility to 0.88%. As a result of the updates to the Company's overall capitalization percentage and the Company's salaries to nonutility, the Company's salaries expensed percentage is 74.5%. The Commission concludes that the resulting percentage of salaries expensed of 74.5% is appropriate and should be made in this proceeding.

Further, witness Fernald testified that in addition to the labor capitalization percentage, the overtime hours are also affected by the hours worked. Witness Fernald contended that it would not be appropriate to adjust the capitalization percentage to reflect the activity for the first five months of 2011 as proposed by the Company without also adjusting overtime hours based on the hours worked for the first five months of 2011. Witness Fernald maintained that if the capitalization percentage is adjusted based on the hours worked during a certain period of time, the overtime hours should also be adjusted, since the capitalization percentage and the overtime hours tend to follow. Witness Fernald further argued that generally, if the capitalization percentage goes down, the overtime hours go down, and it would not be appropriate to adjust one without adjusting the other.

The Commission agrees with the Public Staff that the Company's overall capitalization percentage should be based upon 12 months of historical information rather than only five months of recent activity. Further, the Commission realizes that use of only five months of historical data as recommended by the Company would fail to recognize the differences between the winter months and summer months which could affect the level and type of hours worked. The Commission observes that the differences between capitalization percentages during the winter and summer months is evident when comparing the capitalization percentages calculated by the Company for the first quarter of 2011 of 20.98% to the first five months of 2011 of 22.91%. As shown, the addition of the two spring months of April and May to the data for January through March increased the capitalization percentage by 1.93%. Also, based on the testimony of Company witness Becker, it appears that the Company is not comparing the same periods in 2010 and 2011 in its analysis, but instead is comparing the six months ended June 30, 2010 to the five months ended May 31, 2011. This would not be an appropriate comparison and would likely overstate the decrease in the capitalization percentage between the two periods calculated by the Company because the month of June 2011, a summer month, was excluded.

Further, the Commission also agrees with the Public Staff that it would not be appropriate to adjust the capitalization percentage to reflect the activity for an updated time period as proposed by the Company without also adjusting overtime hours based on the hours worked for that same updated time period. The Commission observes that if the capitalization percentage goes down, the overtime hours go down, and it would not be appropriate to adjust one without adjusting the other.

The Commission finds and concludes that the overall capitalization percentage for use in this proceeding is 24.63% based upon historical data for the 12 months ended March 31, 2011. Accordingly, the Commission finds and concludes that the overtime hours used to calculate salaries and wages should also be adjusted to reflect the hours worked for the 12 months ended March 31, 2011.

Furthermore, based upon the foregoing, the Commission concludes that the Public Staff's adjustment to decrease salaries by $132,904 and benefits by $70,912 to reflect the hours worked for the 12 months ended March 31, 2011 is appropriate and should be made in this proceeding.

(2) Time Spent on Nonutility Work and Acquisitions

This issue concerns the treatment of time spent on nonutility work and acquisitions. Public Staff witness Fernald testified that during her investigation, she found that the level of salaries the Company had allocated to nonutility work and acquisitions was understated due to (1) the Company failing to account for time spent by non-IT employees on affiliated companies and (2) the fact that the Company had been coding time spent on potential acquisitions to expenses. As a result, witness Fernald made adjustments to decrease salaries expense by $71,491, related benefits by $18,303, and related payroll taxes by $5,448 to remove time spent on nonutility work and acquisitions.

Aqua NC opposed the Public Staff's adjustment and argued that it is appropriate for the Company's salaries and wages expense to include time spent by Company employees in performing due diligence and otherwise evaluating potential acquisitions by the Company, even if the subject acquisition is not consummated. In its Proposed Order, the Company stated that it has removed the Public Staff's adjustment, in the amount of $71,491, provided on Fernald Exhibit 1, Schedule 3-2(a) REVISED, Line 6, because it believes that these expenses are properly included in determining the appropriate level of labor expense in this proceeding. Aqua NC contended that if witness Fernald's proposed adjustment in this regard is accepted, there would be further erosion of the Commission-approved troubled system acquisition incentive.

The Company argued that the Public Staff cannot have it both ways. If documented due diligence is a prerequisite for a decision as to whether or not to enter into a contract – whether it be for a lease or for the acquisition of another utility – the reasonable costs of performing the due diligence must be considered prudent. Aqua NC contended that the Commission should encourage due diligence in reviewing possible acquisitions with the knowledge that not every review of a system will lead to an acquisition. Aqua NC asserted that it prudently investigates various opportunities that present themselves and this analysis necessarily involves the expenditure of time by properly trained employees. The Company acknowledged that there are some potential acquisitions which, after proper due diligence, are shown to be clearly not in the best interests of Aqua NC or its ratepayers. However, the Company maintained that this is a legitimate business expense and such "opportunity cost" should be shared with the ratepayers, just as the benefits are shared.

Company witness Becker raised two issues concerning the Public Staff's adjustment. The first issue concerned the Public Staff's removal of time spent by North Carolina employees performing work for affiliated companies. Witness Becker testified that Aqua employees have periodically spent time completing tasks for other states, for example Aqua Virginia and Aqua South Carolina, as recently as 2010, but the only Aqua employee expected to code future time to other entities will be the IT employee. He stated that aside from business development time, which is coded to a specific state's operations where applicable, no other employees will be coding time to Virginia. However, witness Becker further testified that he was unable to determine the necessary revisions to the Public Staff's adjustment related to this issue.

The second issue raised by witness Becker concerned the Public Staff's removal of time spent on potential acquisitions. Witness Becker testified that while not all acquisitions come to fruition, the Company has a history of completing acquisitions that increase the overall North Carolina customer base, which has the benefit of maximizing dilution of existing fixed operating costs while adding only incremental variable expense. Further, witness Becker stated that in order to make prudent acquisition decisions, the time spent on performing due diligence on all potential acquisitions, including those that do not come to fruition, is a necessary part of this process and therefore should be recoverable.

Witness Fernald asserted that while the Company recognized time spent by the IT employee on affiliated companies, the Company failed to account for time spent by other North Carolina employees performing work for affiliated companies. Witness Fernald testified that she adjusted the amount of salaries allocated to nonutility work and acquisitions to reflect the time worked on these activities during the 12 months ended March 31, 2011, based on information provided by the Company. She further explained that she determined the number of hours spent on nonutility work based on the hours charged to nonutility expense and determined the number of hours spent on affiliated companies based on the number of hours charged to the accounts used by the Company to accumulate this time. Further, witness Fernald testified that she had determined the number of hours spent on acquisitions that were coded to expenses based on review of the activity codes used by employees in recording their time.

In its Proposed Order, the Public Staff pointed out that, although the Company argued that a revision should be made to the Public Staff's adjustment to remove time spent by Aqua NC employees performing work for affiliated companies, the Company failed to provide the amount for any adjustment. The Public Staff asserted that Aqua NC's IT and business development employees perform work for other states, and this time should be properly charged to those states and not included in expenses for North Carolina.

Further, witness Fernald argued that time spent on potential acquisitions should not be charged to expenses, but instead should be considered as part of the costs related to the acquisition or potential acquisition. Current customers should not have to pay for costs to serve future customers. Witness Fernald explained that if the acquisition is for a regulated system in North Carolina and is consummated, the costs would then be reviewed and, if they were deemed to be reasonable, they would be capitalized as part of the cost of acquiring the system. Additionally, witness Fernald testified that if the acquisition does not occur, then the accumulated costs related to the acquisition should be written off and should not be recovered from ratepayers.

Furthermore, the Public Staff pointed out that Aqua NC contested the Public Staff's removal of time spent on acquisitions, but the Company had failed to provide the amount related to time spent on acquisitions that should otherwise be included in expenses. The Public Staff noted that the Company had failed to provide any information on the potential acquisitions that its employees worked on during the 12 months ended March 31, 2011, for which it is now requesting rate recovery from current customers.

Public Staff witness Fernald also testified that Aqua NC has recently had at least one potential acquisition that was a non-regulated activity. Witness Fernald observed that over the years Aqua NC has had failed acquisitions, such as the Saxapahaw and Oak Ridge acquisitions, for which the Public Staff had concerns about the due diligence performed by the Company.

Based upon the evidence, the Commission finds and concludes that the Public Staff's adjustment to remove time spent on nonutility work and acquisitions is appropriate and should be approved. First, although the Company contends that a revision should be made to the amount removed by the Public Staff related to time spent by Aqua employees performing work for affiliated companies, the Company has failed to provide evidence for the amounts of any adjustments and, instead, it has simply proposed that the Public Staff's entire adjustment be rejected. Further, Company witness Becker acknowledged that at least the IT and business development employees charge time to other states, although he appears to contradict himself in his rebuttal testimony when he states in one sentence that the only employee expected to code time to other entities is the IT employee, while in the next sentence he indicates that the business development employees will also be coding time to other states. The Commission clearly believes that time spent on performing work for other states should be charged to those states and should not be included in regulated expenses for North Carolina.

Secondly, the Commission understands that although the Company contests the Public Staff's removal of time spent on acquisitions, the Company has failed to provide any information on the potential acquisitions that its employees worked on during the 12 months ended March 31, 2011, for which it is now requesting rate recovery from current customers. The Company did not indicate which of these potential acquisitions the Company expects to consummate; which of the potential acquisitions have failed and why; nor did the Company indicate whether these potential acquisitions are in North Carolina or other states and whether these potential acquisitions are for regulated or non-regulated operations. The Company merely proposed that the Public Staff's adjustment be rejected.

Lastly, the Commission disagrees with the Company's contention that time spent on all potential acquisitions should be included in expenses in setting rates. The Company should not be coding time spent on acquisitions, such as salaries and wages, to above-the-line expenses, but instead they should be accumulated separately and considered as part of the costs related to the acquisition or potential acquisition. The Commission is of the opinion that the reasonableness and prudence of acquisition costs incurred by the Company cannot be determined until the actual facts of the acquisition or potential acquisition are known. If the Company succeeds in acquiring a system, then the costs incurred related to that acquisition, including due diligence performed by the Company, should be reviewed and, if found to be reasonable and prudent, such costs should be capitalized as part of the cost of acquiring that particular system.

In summary, the Commission finds and concludes that the Public Staff's adjustment to decrease salaries expense by $71,491, related benefits by $18,303, and related payroll taxes by $5,448 to remove time spent on nonutility work and acquisitions is reasonable and appropriate in this proceeding.

(3) Executive Compensation

This area of disagreement concerns the Public Staff's recommendation to remove 50% of the compensation for four top executives. Public Staff witness Fernald testified that the Company included in North Carolina expenses, after other adjustments, $325,641 of salaries, benefits, rent, and payroll taxes charged to North Carolina for four top executives, including:

Item	Amount
Chairman/Chief Executive Officer of Aqua America	$127,928
Chief Administrative Officer, General Counsel & Secretary	42,296
Senior Vice President/Chief Financial Officer	36,996
Regional President & Senior VP Corporate & Public Affairs	118,421
Total salaries, benefits, rent, & payroll taxes charged to NC	$325,641

This 50% adjustment by the Public Staff resulted in a total decrease in expenses of $162,821, consisting of decreases of $130,737 in salaries and wages, $26,143 in benefits expense, $3,331 in rent, and $2,610 in payroll taxes.

Witness Fernald further testified that the amounts charged to the Company from its affiliate, Aqua Services, are not arms' length transactions and should be subject to close scrutiny, and it is the Company's burden to provide proof that the charges to regulated expenses are reasonable.

Witness Fernald testified that, based on her investigation, 50% of the salaries, benefits, payroll taxes, and rent for four top executives should be removed for the following reasons:

1) Witness Fernald testified that the Company has failed to properly account for time spent by the four executives on acquisitions. While the Company did respond to a Public Staff data request by indicating that the Chairman and Chief Executive Officer (CEO) of Aqua America spent no time on acquisitions, Public Staff witness Fernald testified that in responses to other data requests, the Company stated that acquisitions in North Carolina are presented to the Chairman & CEO of Aqua America for his review and approval and that he is involved in the analysis related to the sale of systems. Additionally, witness Roberts testified on cross-examination that the CEO, the general counsel, and the regional president all get involved with acquisitions.

   Witness Fernald testified that the Company also failed to keep proper accounting of time spent by the Chief Administrative Officer, General Counsel, and Secretary on acquisitions and failed to provide documentation showing that such time had not been charged to expenses. While the Company responded to a Public Staff data request indicating that the employee spent no time on acquisitions, witness Fernald testified that the employee's job description indicates that he serves as general counsel for the Company and as such, provides legal expertise and oversees all legal affairs of the Company including advice on contracts, including acquisitions. Witness Fernald testified that her review of invoices provided for Aqua Services indicated that the employee was actively involved in at least one acquisition during the test year. Furthermore, legal fees charged by outside counsel involving conference calls with the employee and other Aqua employees concerning acquisitions were charged to the costs for that acquisition, while at the same time, the time spent by the Aqua employees on that same conference call were charged to regulated expenses.

2) Public Staff witness Fernald testified that the Company failed to properly account for time spent on lobbying by Aqua Services employees.

WATER AND SEWER – RATE INCREASE

3) Public Staff witness Fernald testified that the Company failed to properly account for time spent on capital work by some Aqua Services employees. Company witness Roberts confirmed that the four employees are involved in approving capital budgets. Witness Roberts further testified that "[a]s far as capital investment is concerned we – we go through a rigorous capital evaluation process within Aqua that again includes discussions both locally and statewide and then from a corporate perspective, ending with a discussion of our future investment with the chairman of the board of our company."

4) Witness Fernald testified that the Company was unable to provide a formal job description for the Regional President & Senior VP Corporate & Public Affairs and the Company indicated that no formal job description exists.

5) Witness Fernald testified that the total compensation for the four executives had increased dramatically in the three years since the test year that was used in Aqua NC's previous rate case in Docket No. W-218, Sub 274. Witness Fernald testified that the proxy statements for Aqua America indicate that the percentage increases in salaries for these four executives since 2007 are as follows:

Chairman/Chief Executive Officer of Aqua America

Year	Total Compensation	Percentage Increase From Prior Year
2007	$2,089,973	
2008	$2,336,644	11.8%
2009	$2,548,985	9.1%
2010	$3,525,117	38.3%

Total Increase since 2007 – 68.7%

Chief Administrative Officer, General Counsel & Secretary

Year	Total Compensation	Percentage Increase From Prior Year
2007	$761,658	
2008	$801,614	5.3%
2009	$875,033	9.2%
2010	$904,149	3.3%

Total Increase since 2007 – 18.7%

Senior Vice President/Chief Financial Officer

Year	Total Compensation	Percentage Increase From Prior Year
2007	$621,206	
2008	$706,278	13.7%
2009	$794,835	12.5%
2010	$895,065	12.6%

Total Increase since 2007 – 44.1%

Regional President & Senior VP Corporate & Public Affairs

Year	Total Compensation	Percentage Increase From Prior Year
2008	$388,763	
2009	$520,533	33.9%
2010	$626,668	20.4%

Total Increase since 2008 – 61.2%

In rebuttal testimony, Company witness Roberts testified that a confidential report commissioned by Aqua America's board of directors to compare Aqua's executive compensation package to other utilities in its peer group demonstrated that the compensation of the four executive's in question is at or below the utility industry benchmark. However, witness Fernald testified, on cross-examination, that she reviewed the study in question and that, while it was true that the study indicated that the targeted compensation for Aqua employees was below the targeted compensation for comparable companies, review of the 2010 proxy statement indicated that the actual cash incentives for the four executives at issue here were 60% greater than target.

Witness Roberts testified that a reduction of executive compensation for the four executives at issue is unwarranted. Witness Roberts asserted that the four executives provide a unique benefit to ratepayers with their management and guidance of Aqua America and the Company, and that North Carolina customers benefit from a strong Aqua America.

As the Commission stated in its Order Granting Partial Rate Increase in Docket No. W-274, Sub 478, it is necessary to closely examine charges and allocation of costs from affiliated companies since these transactions are at less than arms' length and affiliated relationships provide an opportunity and incentive for companies to maximize profits of the combined affiliated companies. *See* State ex rel. Utilities Comm'n v. Morgan, 7 N.C. App. 576, 588-589, 173 S.E.2d 479, 487-488 (1970) (Commission to examine closely transactions between utilities and affiliated companies to protect ratepayers from excessive rates), *rev'd on other grounds*, 277 N.C. 255, 177 S.E.2d 405 (1970), *adhered to on reh'g*, 278 N.C. 235, 179 S.E.2d 419 (1971).

Based on our review of the record in this case, the Commission finds that the charges proposed by the Company are not reasonable. First, the level of executive compensation included by the Company in regulated expenses is overstated for the following reasons: (1) the

Company has not properly accounted for the time spent by executives on acquisitions; (2) the Company has not adequately accounted for the time spent by employees on lobbying activities; and (3) the Company has not adequately accounted for executive time spent on capital work activities. The Company should be responsible for properly accounting for time spent by employees, including ensuring that time spent on acquisitions, capital projects, and lobbying is properly accounted for and is not included in regulated expenses. Due to the failure of the Company to keep accurate accounting records of the time spent by its employees, and the charges from employees of affiliated companies, the level of salaries and wages proposed by the Company in this case is overstated.

Second, there has been a dramatic increase in the compensation for the four employees over the past three years that has not been proven to be a reasonable expense to be recovered from ratepayers. For example, the compensation for the Chairman/Chief Executive Officer has increased 68.7% in three years, and the compensation for the Regional President & Senior VP Corporate & Public Affairs increased 61.2% in two years. These significant increases in compensation occurred during a time of high unemployment and slow economic growth with little or no pay increases for many workers.

Based upon the foregoing, the Commission agrees with the Public Staff that the level of executive compensation charged as an expense to North Carolina customers that the Company proposed is not reasonable for the reasons previously articulated. However, the Commission does not agree that the factors articulated by the Public Staff merit a 50% reduction in the level of executive compensation charged as an expense to North Carolina customers. After carefully considering the arguments of the Public Staff and the counter arguments advanced by the Company, the Commission concludes that, on balance, a 25% reduction charged as expense to North Carolina customers is reasonable and that the $325,641 in expenses sought by the Company for the executive compensation for the four employees should be reduced by the amount of $81,410, consisting of decreases of $65,368 in salaries and wages, $13,072 in benefits expense, $1,666 in rent, and $1,304 in payroll taxes.

(4) Medical Benefits for New Employees

The final area of disagreement in the levels of salaries and benefits between the Company and the Public Staff concerns the appropriate levels of medical and dental benefits for new employees who have not yet selected their insurance coverage. Public Staff witness Fernald testified that under the Company's new benefit policy, effective January 1, 2011, there is a 90-day delay from when an employee starts with the Company and when he or she is eligible for medical and dental benefits. Due to this delay, the level of benefit coverage for several Aqua NC employees is unknown, since the coverage elections have not yet been made by the new hires or such elections have not yet started. Witness Fernald testified that she had several problems with the Company's calculation of benefits for new employees: (1) in its calculation of the average premium calculation, the Company failed to include employees who opted out of coverage; (2) due to turnover, the Company will usually have some new employees, and will generally have some employees who are not eligible for medical benefits; and (3) the Company assumed that some employees will elect coverage beyond employee only, which may or may not be the case. Due to these concerns, witness Fernald recommended that medical and dental benefits for new employees be calculated based on employee-only coverage, which resulted in adjustments to decrease medical and dental benefits by $92,440.

Company witness Becker testified that, as of January 1, 2011[1], Aqua America, Inc. revised its employee benefit plan to include a provision delaying insurance benefit coverage until 90 days after a new hire starts work with the Company. As a result, several existing Aqua NC employees had not, as of the time of the testimony in this case, made their insurance coverage selection. Consequently, that expense was imputed in order to estimate the benefits expense to be incurred by the Company.

Witness Becker submitted that the average Aqua NC employee benefit expense, based on the insurance coverage choices actually made by Company employees, is the appropriate methodology to impute benefits expense, where necessary. In his rebuttal testimony, witness Becker revised his calculation of the monthly average cost of insurance coverage, in light of one of Public Staff witness Fernald's criticisms, to include in its averaging process those employees who have opted out of insurance coverage. As a result, witness Becker recalculated the average medical insurance benefit expense for the Company to be $859.82 per employee, per month. The Company contended that the average monthly expense of $859.82 is an appropriate amount to apply to those employee positions which have not yet made an insurance coverage selection, rather than the employee-only coverage expense amount proposed by the Public Staff, which is the lowest cost insurance coverage available. However, during cross-examination, witness Becker acknowledged that his average medical expense per employee does not reflect the 90-day period during which the Company will not pay medical benefits.

The Public Staff recognized that the Company is not paying benefit coverage for several Aqua NC employees included in this case due to its 90-day delay policy, which was adopted January 1, 2011. The Public Staff explained that the Company will have employee turnover, and due to this turnover, there will always be some employees for which the Company will not be paying medical benefits. The Public Staff pointed out that the Company did not factor the 90-day delay into its calculation of the average medical benefits per employee.

When the actual amount of medical benefits cannot be determined since the final benefit selection has not been made, the Public Staff contended that it is appropriate to use the minimum amount for that expense. Consequently, witness Fernald recommended that medical benefits for new employees be calculated based on employee-only coverage at a monthly cost of $473.30 per employee, per month, for medical insurance coverage only.

Further, witness Fernald testified that due to the 90-day delay, with the turnover the Company has, the Company will always have some employees for whom it will not be paying benefits. Witness Fernald stated that the Company did not provide any documentation as to what election the new hires have made; although she thought that a few of the new hires had been employed by Aqua at least 90 days. Witness Fernald explained that using the average as proposed by the Company will overstate the amount since it fails to recognize that with the 90-day delay there will always be some employees for which the Company will not be paying

[1] During cross-examination, witness Becker agreed that this new plan went into effect on January 1, 2011, not January 1, 2010, as he had stated in his rebuttal testimony.

benefits. Furthermore, when asked on cross-examination if every new hire does not select employee-only coverage, will the Company not recover its costs, witness Fernald testified that if some of the new employees opt out of coverage and others select employee-only coverage, then the Public Staff's recommended amount would be higher than the Company's cost.

Due to the Company's new benefit policy, there is a 90-day delay from when an employee starts with the Company and when that employee is eligible for medical and dental benefits and, consequently, the Company is not currently paying medical benefits for several Aqua NC employees included in this case. The issue at hand is what amount should be included for medical and dental benefits for these new employees.

The Commission does not agree with either the Company's or the Public Staff's recommendations in this regard. Instead, the Commission finds and concludes that the Company's cost of providing medical and dental insurance benefits for new employees who have not yet selected their insurance coverage should be determined based upon the Company's average annual medical and dental benefits cost, respectively, adjusted to reflect the Company's new insurance benefits policy, effective January 1, 2011, which imposes a 90-day delay from when an employee starts with the Company and when he or she is eligible for medical and dental benefits. The Commission is of the opinion that this methodology yields a reasonable and equitable computation of the Company's expected ongoing cost for medical and dental benefits and provides due consideration of the reduction in cost resulting from the Company's 90-day delay policy for new employees.

In order to specifically quantify the effects of this decision for purposes of completing the Commission's determination of Aqua NC's overall annual revenue requirement, the Commission issued an Order Requiring Verified Information on August 25, 2011. On August 29, 2011, Aqua NC provided the required information that is pertinent to the Commission's final computations on this issue. Based upon the foregoing, the Commission finds and concludes that the Company's cost of providing medical and dental insurance benefits for new employees who have not yet selected their insurance coverage should reflect Aqua NC's reasonable costs in that regard, which is $644.87 per month, per employee for medical benefits and $40.46 per month, per employee for dental benefits. Accordingly, it is appropriate to decrease Aqua NC's medical benefits expense by $55,674 and its dental benefits expense by $2,542 to reflect a reasonable level of medical and dental insurance benefits for the new employees in this proceeding.

Rent Expense

As previously discussed in this Order, the Commission has concluded that the Public Staff's adjustment to remove 50% of the compensation for four top executives is inappropriate and instead has concluded that the removal of 25% of the compensation for four top executives is appropriate. Therefore, it is appropriate to also remove 25% of the allocated rent for these executives, resulting in a decrease in rent expense of $1,666.

Transportation Expense

The Company disagreed with the Public Staff's proposed adjustment to calculate Aqua NC's fuel cost expense based on a three-year historical average of $2.77 and $3.08 per gallon for unleaded and diesel, respectively. Company witness Becker testified that using either the current fuel prices or independent third-party estimates, such as the US Energy Information Administration's (EIA) forecasted average prices for fuel, would provide the most accurate estimates of prospective fuel expense that the Company can be expected to incur. Witness Becker stated that, as recorded on June 1, 2011, the EIA forecasts the 2011 average price per gallon at $3.63 and $3.89 for unleaded and diesel, respectively. Further, as shown by Aqua NC Fernald Cross-Examination Exhibit No.1, as of June 16, 2011, the average fuel prices in North Carolina were $3.621 per gallon for unleaded and $3.916 per gallon for diesel according to the American Automobile Association. Witness Becker testified that for 2012, the forecasted price per gallon is $3.66 for unleaded and $3.93 for diesel.

Witness Becker contended that in light of current reality, the Public Staff's approach of using a three-year historical average would immediately require the Company to subsidize fuel expense at nearly $1.00 per gallon which would have significant ramifications for the Company as Aqua NC buys more than 280,000 gallons of fuel per year. Aqua NC contended that applying the Public Staff's recommended fuel prices would not allow the Company a realistic opportunity to recover the known and measureable prices at the time of the evidentiary hearing. The Company concluded that it is reasonable and appropriate to use the 2011 forecasted average price per gallon of $3.63 and $3.89 for unleaded and diesel, respectively, to calculate the Company's fuel cost expense used to establish rates in this proceeding.

Witness Fernald disagreed with the Company's April 15, 2011 update to reflect projected gasoline prices because (1) rates in North Carolina are based on historical costs, not forecasted or projected amounts and (2) it is inappropriate to adjust gasoline prices to a projected average price for a short-term period. Witness Fernald testified that gasoline prices in the past five years have varied widely, and if an adjustment is made, the historical amounts over a longer period should be evaluated in determining the adjustment. Witness Fernald testified that based on the weekly gasoline prices for the lower Atlantic region published by the Department of Energy, the average gasoline prices for various historical periods have been as follows:

Time Period	Regular	Diesel
Test year (12 ME 7/31/2010)	$2.63	$2.81
Calendar year 2010	$2.72	$2.95
Three-year average as of 4/18/11	$2.77	$3.08
Five-year average as of 4/18/11	$2.76	$3.01

Witness Fernald contended that it is not appropriate to use projected gasoline prices but rather when prices are fluctuating widely, it is appropriate to use an historical average to smooth out such fluctuations. Witness Fernald testified that based upon a review of these average historical prices, the Public Staff concluded that the three-year average gasoline prices of $2.77 for regular and $3.08 for diesel are appropriate for use to determine transportation expense in this proceeding. The Public Staff asserted that such conclusion is consistent with the Commission's practice of using three years for normalization and amortization of other expenses, such as rate case expense.

The Commission agrees with the Public Staff that it is not appropriate to use projected gasoline prices in establishing the amount of fuel cost expense for use in this proceeding because rates in North Carolina are based on historical costs, not forecasted, or projected amounts. Further, the Commission agrees with the Public Staff that when prices are fluctuating widely, it is appropriate to use an historical average to smooth out such fluctuations. The Commission concludes that the Company's fuel cost is to be calculated based upon the three-year historical average of $2.77 per gallon for unleaded gasoline and $3.08 for diesel.

Based upon the foregoing, the Commission concludes that the Public Staff's adjustment to decrease transportation expense by $169,756 to reflect the three-year average gasoline prices is appropriate and should be made in this proceeding.

In addition, transportation expense is also impacted by a fallout adjustment related to one of the salaries and wages expense issues, previously addressed herein. In particular, as discussed under the evidence and conclusions for Findings of Fact Nos. 33 and 34, the Commission concluded that it is appropriate to calculate Aqua NC's salaries and wages expense based upon the actual number of employees as of the hearing date and that it is appropriate to use the resulting percentage of salaries expensed of 74.5%. As a result, the Commission concludes that the transportation expense should be decreased by $4,639 to reflect the hours worked for the 12 months ended March 31, 2011.

<u>Contractual Services – Other</u>

The Company and the Public Staff disagreed on the following items concerning contractual services – other: (1) water filter backwash hauling and (2) sewer jetting expense.

(1) <u>Water Filter Backwash Hauling</u>

The Public Staff and the Company disagreed on the appropriate amount of expense for contract water filter backwash hauling for Chesapeake Pointe.

Public Staff witness Furr testified that Chesapeake Pointe is a small water system approved for 95 residences and a clubhouse which only had approximately 32 end-of-test-year customers. According to information supplied by the Company, witness Furr stated that most of the homes are not occupied. Witness Furr explained that at full build out of the service area, the pro forma adjustment proposed by the Company in its application would amount to $28 per month per customer and for the end-of-test-year customers it would be approximately $83 per month. Witness Furr stated that the Company's proposed pro forma adjustment appeared high. Based upon the Company's responses to various Public Staff data requests, witness Furr recommended an adjustment to reduce the Company's proposed pro forma amount.

The Company argued that including the full amount of water filter backwash hauling expense related to its Aqua water operations is appropriate for ratemaking purposes and is consistent with prior Commission decisions. Aqua NC contended that the approach advocated by witness Furr is inconsistent with the consolidated rate structure the Commission previously approved for Aqua NC. The Company asserted that it is inconsistent to evaluate certain individual expenses in a rate case proceeding on a system-specific, per customer basis for a determination of reasonableness. Aqua NC opined that the fact that the Chesapeake Pointe system had 32 of 95 projected residences on line at the end of the test year does not affect the validity and necessity of the water filter backwash hauling expense.

In its Proposed Order, Aqua NC maintained that this is a necessary expense that the Company incurs regardless of the number of homes that have been built in this development. As a result, the Company argued that it is appropriate for the Company's rates to be calculated so as to cover its operating expenses for such hauling activity.

Based upon the foregoing, the Commission agrees with the Company that the fact that this system had 32 of 95 projected residences on line at the end of the test year does not affect the validity and necessity of this expense. The Commission finds and concludes that Aqua NC's actual expense for water filter backwash hauling for the Chesapeake Point system is $30,024, and this amount is appropriate to include in the Company's expenses for ratemaking purposes in this proceeding.

(2) Sewer Jetting Expense

The Company and the Public Staff disagreed on the level of sewer jetting expense to be included in contractual services – other. Aqua NC proposed to include total annual sewer jetting expense of $109,175, comprised of $77,173 related to its annual 10% jetting requirements and $32,002 related to annual maintenance jetting and unplanned jetting related to problems and/or emergencies. Public Staff witness Furr contended that the 10% annual jetting requirement is a rule of thumb for a reasonable and prudent level of jetting and recommended an annual sewer jetting expense of $75,153 based upon Aqua NC's gravity sewer main inventory at a cost of $1.00 per foot, excluding 20,200 feet of main for Cannonsgate. The cost of $1.00 per foot was not contested.

The account of interest is Contractual Services–Other–Pump Maintenance. Witness Furr reclassified $91,514 of expense in this category to Contractual Services–Other-Sewer Collection Maintenance Hauling, and this adjustment was not contested by Aqua NC. The remainder of the account is $140,742, which witness Furr replaced with $75,153 of annual sewer jetting expense, comprised of $62,085 for Aqua sewer, and $13,068 for Fairways sewer.

Witness Furr testified that he made calculations in this present case similar to the pro forma calculation Aqua NC made in the filing of its last rate case proceeding in Docket No. W-218, Sub 274, where Aqua NC increased the expense to a level equal to jetting 10% of gravity sewer mains. In this case, witness Furr also removed the cost for jetting the mains for Cannonsgate, where there were only two test-year customers on the system with 20,200 feet of sewer mains (20,200 times 10% times $1.00 per foot = $2,020).

On cross-examination witness Furr testified that "[p]reventative cleaning is not required for sewer lines less than five years old unless inspection otherwise reveals a need for cleaning or cleaning is required by a sewer line extension permit." Witness Furr stated that the first customer was served in Cannonsgate in May 2010; consequently, Aqua NC would not be required to clean the Cannonsgate sewer mains for five years.

Witness Roberts testified that jetting sewer lines is an important part of sewer maintenance and is operationally necessary to insure that blockages do not occur. Witness Roberts contended that the 10% compliance jetting requirement is a floor, not a ceiling. He urged the Commission to recognize that compliance jetting of 10% of the Company's sewer mains does not mean the Company will not have additional sewer jetting expense, as operational realities are such that there are other instances in which unplanned jetting work must be done in order to maintain service, prevent larger problems, and address emergencies.

Witness Becker provided SVB Jetting Exhibit Schedule 1 showing Aqua NC has incurred an average of $122,013 in scheduled jetting expense during the previous two years. He testified on rebuttal, that the Company agrees with adjusting the amount down to the 10% minimum as recommended by the Public Staff, but that jetting related to Cannonsgate should be included. Witness Becker asserted that an amount of $77,173 should be used as a minimum starting point ($75,153 + $2,020). He then testified that Aqua NC's records show an additional two-year average amount of jetting of $32,002 above and beyond the cost of what Aqua NC described as minimum jetting requirements. Aqua NC contended that the Company should be allowed to recover total annual jetting expense of $109,175 ($75,153 + $2,020 + $32,002).

The Commission recognizes that Aqua NC and the Public Staff are in agreement regarding the recommended amount of sewer jetting expense related to the annual 10% cleaning requirement with the exception of the $2,020 in expense related to the Cannonsgate mains. Based upon the testimony of witness Furr, the Commission understands that preventative cleaning is not required for sewer lines less than five years old unless inspection otherwise reveals a need for cleaning or cleaning is required by a sewer line extension permit. Witness Furr testified that the Cannonsgate system is a new system as the first Cannonsgate customer was served in May 2010. Accordingly, the Commission concludes that it is inappropriate to include the $2,020 in annual expense related to the annual 10% cleaning requirement for 20,200 feet of main in Cannonsgate.

With respect to the $32,002 amount proposed by the Company related to annual maintenance jetting and unplanned jetting related to problems and/or emergencies, the Commission is persuaded by the testimony of witnesses Roberts and Becker that the Company annually incurs expense for maintenance jetting and unplanned jetting above and beyond the cost of complying with minimum jetting requirements. The Commission believes that such expenses are an important part of sewer maintenance and are operationally necessary to insure that blockages in the system do not occur. The Commission finds and concludes that Aqua NC should be allowed to recover its reasonable expenses related to annual maintenance jetting and unplanned jetting to address problems and/or emergencies as they occur. Consequently, the Commission concludes that the appropriate level of sewer jetting expense to be included in this proceeding is $107,155, comprised of $88,647 for Aqua sewer and $18,508 for Fairways sewer.

Insurance Expense

The Company and the Public Staff are in disagreement on (1) the percentage of insurance costs to be capitalized, and (2) the level of insurance claims to be included in insurance expense in this proceeding.

(1) Capitalization Percentage

As previously discussed under salaries expense, the Commission concludes that the Public Staff's adjustment to reflect the hours worked for the 12 months ended March 31, 2011 and the resulting percentage of salaries expensed of 74.5%, is appropriate and should be made in this proceeding.

(2) Insurance Claims

This issue concerns the appropriate calculation of Aqua NC's expense for the cost of insurance claims paid by the Company for workers compensation, general liability, and automobile insurance.

In rebuttal testimony, Company witness Becker advocated use of a five-year average for insurance claims expense to calculate recoverable expenses, consistent with the recovery of insurance claims expense in the two most recent Aqua NC rate cases (Docket Nos. W-218, Subs 274 and 301), which were both stipulated rate cases. Witness Becker testified that a longer period of time allows for claims to fully develop and provides a better approximation of claims expense. Further, witness Becker testified that the Public Staff's proposal to use a three-year average, rather than the methodology used in the past several rate cases, appears to be a result-oriented effort that does not reflect an adequate claims history period. Witness Becker maintained that a consistent methodology, reasonably calculated to accurately predict the match between an appropriate expense and the period in which it is incurred, should be applied to the ratemaking calculation here.

In its Proposed Order, the Company commented that it believes it would be more appropriate to base the determination of this expense on third-party determined actuarial expense recorded on the Company's books, but the Company observed that it had stipulated to use of the five-year methodology in its most recent two rate cases and it is now recommending that the insurance claims expense should be calculated using a five-year average in this present rate case. However, in the record in this proceeding, the Company did not actually provide a calculation indicating or stating what its actual recommended amount is for an appropriate level of insurance claims expense for inclusion in this proceeding based upon a five-year average.

Public Staff witness Fernald testified that she adjusted claims for workers compensation, general liability, and automobile insurance to reflect the average claims paid for the last three years. As shown on Revised Fernald Exhibit I, Schedule 3-10(a), witness Fernald calculated her recommended level of claims to be included in expenses in this case as follows:

Item	Three-Year Average of Claims	Percent Expensed	Amount Charged to Expenses
Workers compensation claims	$214,221	74.5%	$159,595
Automobile claims	13,397	74.5%	9,981
General liability claims	38,033	100.0%	38,033
Total	$265,651		$207,609

On cross-examination, witness Fernald testified that while a five-year average was used in the last stipulated rate case (Docket No. W-218, Sub 274), a four-year average was used in the last litigated rate case, which was a rate case for Heater Utilities, Inc. (Docket No. W-274, Sub 478). Witness Fernald stated that if she had used a four-year average in this case, the claims would actually be less than what she is recommending. In response to questions from the Commission at the evidentiary hearing, witness Fernald observed that the differences between the three-year, four-year, and five-year averages were not significant in total and that she believes the three-year average is a reasonable level. The three-year average is $265,651, the four-year average is $253,126, and the five-year average is $277,801.

Based upon the evidence, the Commission is not persuaded that adoption of the Public Staff's proposal for the use of a three-year average, in departure from the Commission's prior acceptance of a five-year average for insurance claims expense to calculate recoverable expenses, consistent with the recovery of insurance claims expense in the two most recent Aqua NC rate cases (Docket Nos. W-218, Subs 274 and 301), which were both stipulated rate cases, is warranted. Based on the amounts of the three-year, four-year, and five-year averages for claims paid, the Commission believes that the use of the five-year average of actual claims paid, consistent with our past practice, is reasonable and appropriate. Accordingly, the Commission finds and concludes that the five-year average of actual insurance claims paid, in the amount of $277,808[1], is the reasonable amount for use in determining the appropriate level of claims expense for workers compensation, general liability, and automobile insurance for use in this proceeding.

In order to specifically quantify the effects of this decision for purposes of completing the Commission's determination of Aqua NC's overall annual revenue requirement, the Commission issued an Order Requiring Verified Information on August 25, 2011. Therein, the Commission requested that the Company provide the amounts for workers compensation claims, automobile claims, and general liability claims, which are the three components in the five-year average of actual claims paid for North Carolina. On August 29, 2011, Aqua NC provided the required information. Based upon the foregoing, the Commission finds and concludes that the appropriate level of insurance claims expense to be included in this case is $226,607, which properly reflects that workers compensation claims in the amount of $185,560 and automobile claims in the amount of $15,228 should be allocated to this expense based on the percentage of salaries expensed of 74.5% and the general liability claims expense in the amount of $77,020 should be 100% included.

[1] The five-year average of $277,801 was corrected to $277,808 per the Company's filing on August 29, 2011, which was provided in response to the Commission Order requiring information issued August 25, 2011. The Public Staff agreed with that correction.

Based on the foregoing, the Commission concludes that the appropriate level of insurance expense for use in this proceeding is $598,617.

Summary

Based upon the foregoing and the evidence and conclusions for Finding of Fact No. 45 regarding the appropriate level of rate case expense, as addressed hereinbelow, the Commission finds and concludes that the appropriate level of O&M and G&A expenses for the combined operations, for use in this proceeding, is as follows:

Item	Amount
Salaries and wages	$ 7,863,995
Employee benefits	1,899,211
Purchased water / sewer	1,369,036
Sludge removal	427,572
Purchased power	2,888,587
Fuel for power production	10,067
Chemicals	1,126,469
Materials and supplies	269,109
Testing fees	980,686
Transportation	1,460,236
Contractual services	3,048,548
Rent	575,663
Insurance	598,617
Regulatory commission expense	192,122
Miscellaneous expense	1,422,005
Interest on customer deposits	23,979
Annualization & consumption adjustments	80,293
System transfer/abandonment adjustments	(424,280)[1]
Total O&M and G&A expenses	$23,811,915

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 45

The evidence supporting this finding of fact is contained in the Company's application, the testimony of Public Staff witness Fernald, the Company's affidavit as to rate case expense filed August 15, 2011, the Public Staff's comments filed August 24, 2011, PSS' comments filed August 25, 2011, and the Company's response filed on August 29, 2011.

At the time of filing its Proposed Order, the Public Staff had used the rate case expenses provided in the Company's January 21, 2011 application of $278,297, consisting of $223,497 for various projected future costs through completion (legal fees, service company employee

[1] This amount includes the corresponding adjustments to the total amount of expense to be removed from this proceeding related to the 21 customers on two Virginia water systems based on conclusions regarding the appropriate levels of O&M and payroll tax expense reached elsewhere in this Order. The methodology used in computing the fallout amount for the related Virginia system adjustments is not contested by the Company. The total amount of expense reduction related to the Virginia water systems is $5,766.

expenses, postage, printing, etc.) for the current proceeding; $40,000 for the depreciation study performed by Gannett Fleming, Inc.; and $14,800 for the volumetric sewer and block rates study performed by UNC-Chapel Hill, School of Government, Environmental Finance Center. In addition, the unamortized balance of rate case expenses of $155,096 from prior rate case proceedings in Docket Nos. W-218, Subs 274 and 301 were also taken into consideration. The expense for the depreciation study was proposed to be amortized over five years, as proposed by Aqua NC, and the remaining $393,393 of expenses were proposed to be amortized over three years, resulting in the Public Staff's initial recommended annual level of $139,131 for rate case expenses.

In its Brief, the Company noted that in its application it had estimated the rate case expenses to be incurred in this proceeding. However, the Company explained that, as it has now turned out, Aqua NC's original projection as to estimated rate case expenses does not begin to account for the legal fees associated with fully litigating a rate case through three days of evidentiary hearings or the expenses associated with securing testimony from the Company's cost of capital witness, Pauline Ahern[1], and the Company's depreciation witness, John Spanos[2]. As a result, the Company stated that its initial estimate did not reflect the reality of the expert witness fees, legal fees, or other Company expenses incurred up through and including preparation and filing of its Brief and Proposed Order in this proceeding.

Consequently, subsequent to the filing of proposed orders and briefs, on August 15, 2011, Aqua NC filed an affidavit which provided updated rate case expenses for costs incurred through the conclusion of this proceeding. On August 19, 2011, the Commission issued a Post Hearing Order Requiring Response by the Public Staff and PSS to Aqua NC's rate case expense affidavit.

On August 24, 2011, the Public Staff filed comments stating that it had reviewed the invoices and other documentation provided by the Company and was satisfied that the Company had appropriately documented its updated rate case expense. The Public Staff explained that the total rate case costs are now $595,705, consisting of the following:

Item	Amount
Costs for current proceeding	$377,527
Depreciation study	48,342
Volumetric study	14,800
Total current rate case and studies	440,669
Unamortized balances from prior cases	155,036
Total rate case costs	$595,705

On August 25, 2011, PSS responded that it took no position regarding Aqua NC's affidavit as to rate case expense. On August 29, 2011, Aqua NC responded that it agreed with the Public Staff's updated calculation of rate case expense.

[1] Aqua filed Ms. Ahern's prefiled direct testimony on May 2, 2011 and her rebuttal testimony on June 3, 2011.

[2] Aqua filed Mr. Spanos' rebuttal testimony on June 3, 2011.

WATER AND SEWER – RATE INCREASE

Based upon the foregoing, the Commission is of the opinion that it is reasonable and appropriate to allow Aqua NC to update its rate case expenses and to accept that the Company's total rate case costs are $595,705, as agreed to by Aqua NC and the Public Staff, consisting of $377,527 in costs for the current proceeding; $48,342 for the depreciation study; $14,800 for the study on volumetric sewer rates and an increasing block rate structure for water; and $155,036 in unamortized balances from the Company's two most recent prior rate case proceedings, Docket Nos. W-218, Subs 274 and 301. The Commission finds and concludes that the rate case costs, as updated, should be amortized over three years, except that the depreciation study costs should be amortized over five years, resulting in annual rate case expenses (regulatory commission expense) as follows:

Aqua Water	$111,570
Aqua Sewer	25,031
Fairways Water	6,904
Fairways Sewer	4,838
Brookwood Water	43,779
Total Combined Operations	$192,122

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 46 THROUGH 52

The evidence supporting these findings of fact is contained in the testimony of Public Staff witnesses Fernald and Furr and Company witnesses Becker, Spanos, and Roberts, and the Gannett Fleming depreciation study filed by Aqua NC on November 29, 2010, in Docket No. W-218, Sub 274. The Company's level of depreciation and amortization expense for its combined operations, as presented in its application, is $7,528,588. The Public Staff's recommended level of depreciation and amortization expense is $5,967,460, resulting in a difference of ($1,561,128).

In consideration of the Joint Stipulation between the Company and the Public Staff and the Company's acceptance of many of the Public Staff's adjustments as reflected in its Proposed Order and in the revisions made by the Public Staff in its supplemental testimony and in Revised Fernald Exhibit I, the Company does not dispute the following Public Staff adjustments to depreciation and amortization expenses:

Item	Amount
Adjust post test-year additions	($297,021)
Remove plant costs related to future customers	(6,039)
Remove project not yet in service	(3,471)
Capitalize legal fees for Northgate well	416
Include documented plant items	1,027
Adjust acquisition incentive adjustments	15,337
Include negative acquisition adjustment for Emerald Plantation	(13,162)
Update rate base to December 31, 2010	50,936
Correct depreciation rate for tools account	(36,894)
Remove Windsor Oaks	(13,519)
Remove systems to be sold	(30,522)
Total	($332,912)

Therefore, the Commission finds and concludes that the adjustments listed above, which are not contested, are appropriate adjustments to be made to depreciation and amortization expense in this proceeding.

Based on the testimony of Company witnesses Becker, Spanos, and Roberts, the Company disagreed with the following Public Staff adjustments to depreciation and amortization expense:

Item	Amount
Remove excess capacity for four treatment plants	($130,262)
Adjust depreciation expense on 2006 IT assets	(595,263)
Adjust depreciation rates to remove net salvage value	(502,691)
Total	($1,228,216)

Excess Capacity

The Public Staff made an adjustment to reduce depreciation and amortization by $130,262 to remove the percentage of depreciation and amortization expense related to excess capacity for the following four WWTPs:

WWTP	Depreciation & Amortization Expense	Excess Capacity Percent	Excess Capacity Adjustment
Carolina Meadows	$171,275	43.65%	$ 74,762
Chapel Ridge	35,150	94.38%	33,175
Country Woods East	14,238	47.10%	6,706
The Legacy at Jordan Lake	16,013	97.54%	15,619
Total excess capacity adjustment			$130,262

As discussed elsewhere in this Order, the Commission has concluded that the excess capacity adjustment to remove a percentage of plant and CIAC related to excess capacity should be limited to only two plants (Carolina Meadows and The Legacy at Jordan Lake). Accordingly, consistent with the Commission's excess capacity percentages, the adjustment should be derived as follows:

WWTP	Depreciation & Amortization Expense	Excess Capacity Percent	Excess Capacity Adjustment
Carolina Meadows	$171,275	31.89%	$ 54,620
The Legacy at Jordan Lake	16,013	94.33%	15,105
Total excess capacity adjustment			$ 69,725

The Commission finds and concludes that the corresponding adjustment to remove $69,725 of depreciation and amortization expense is appropriate and should be made in this proceeding.

Depreciation on 2006 IT Assets

The Company has $2,430,242 of 2006 information technology (IT) assets, which were depreciated over a five-year life in prior rate cases. Included in these IT assets are costs related to the implementation of the call centers and the conversion of the billing system. Based on a depreciation rate of 25.73%, as proposed by the Company in the depreciation study for Account 340.10 - Computer Equipment, the Company has included $625,301 in annual depreciation expense related to these assets.

Public Staff witness Fernald testified that the call centers and conversion of the billing and general ledger systems were large projects, which are not an everyday or even every year occurrence, and it is not appropriate to include in rates an annual level of depreciation expense of $625,301 for these assets that will be fully depreciated as of June 30, 2011. Therefore, witness Fernald recommended that the 2006 IT assets be removed from the general pool of computer equipment and receive special amortization.

Company witness Spanos is employed by Gannett Fleming, Inc. and he prepared the depreciation study filed with the Commission in Docket No. W-218, Sub 274, pursuant to Commission Order. Mr. Spanos is an independent consultant, selected by Aqua NC and endorsed by the Public Staff, to complete the depreciation study, as required by the Commission. The depreciation study encompasses group depreciation procedures. The depreciation rates established in the study were used to support the recoverable depreciation expense submitted by Aqua NC in this rate case. Witness Spanos explained that depreciation refers to the loss in service value that is not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes that can be reasonably anticipated or contemplated, against which the Company is not protected by insurance.

Witness Spanos testified in opposition to witness Fernald's proposal to isolate one particular asset in Account 340.10 - Computer Equipment. He asserted that witness Fernald has reached out past the test year and used her own judgment to implement special treatment due to the high depreciation expense associated with that account. Witness Spanos contended that the Public Staff's proposed treatment is unfair and unwarranted. Witness Spanos argued that these were important and large investments that require recovery. Further, witness Spanos stated that all assets in this account have an average service life of five years. Witness Spanos opined that witness Fernald's statement that these assets will be fully depreciated as of June 30, 2011 is only true in theory, not in reality, since (1) we are dealing with group depreciation, not component depreciation, so full recovery only applies when the book reserve is equal to the full service value of the entire account; (2) depreciation rates are based on the remaining life method, so some assets last longer than the average and others do not last as long as the average; and (3) based on what we know today for these assets, the rate applicable and approved for this account in 2006 was insufficient to recover the full $2.4 million of investment over the five years. Witness Spanos asserted that the $625,301 of depreciation expense related to the $2.4 million in 2006 IT assets is required to achieve full recovery while in service.

Witness Fernald testified that the call centers and conversion of the billing and general ledger systems were large projects, which are not an everyday or even every year occurrence, and it is inappropriate to include in rates an annual level of depreciation expense of $625,301 for these assets which will be fully depreciated as of June 30, 2011. Therefore, witness Fernald recommended that the 2006 IT assets be removed from the general pool of computer equipment and receive special amortization. Since the IT assets have been updated through March 31, 2011, witness Fernald recommended that the unamortized balance of 2006 IT assets as of March 31, 2011, which is $121,514, be amortized over three years, resulting in an annual amortization of $40,505, which is $584,796 less than the depreciation expense calculated by the Company. Further, witness Fernald testified that in order to coordinate her adjustment with the depreciation rate for computer equipment, she requested that the Company provide a calculation of the depreciation rate for this account if the 2006 IT assets are removed from the account and given separate treatment. Based on the Company's response, the depreciation rate for the computer equipment account would change to 25.48%, if the 2006 IT assets are removed. Witness Fernald recommended that this revised rate of 25.48% be used for Account 340.10 – Computer Equipment, and she adjusted depreciation expense for the remaining IT assets to reflect this revised depreciation rate, resulting in a decrease to depreciation expense of $10,467.

Based upon the foregoing, the Commission disagrees with the Company's assertion that the 2006 IT assets were not fully depreciated as of June 30, 2011 due to the Company's use of group depreciation. This assertion, along with the Company's other objections to this adjustment, is based on the assumption that Aqua has been using group depreciation. This assumption is incorrect. Historically and currently, the Company has not used group depreciation as stated by witness Spanos. Instead, depreciation rates for each asset were applied based on the year that the asset was placed in service and depreciation expense stopped being calculated when the asset was fully depreciated. This is evident in the depreciation calculations in the Company's last general rate case, Docket No. W-218, Sub 274, and in the calculation of accumulated depreciation in this case. The Company will not actually convert to using group depreciation until the Commission approves the new depreciation rates in this proceeding.

The Commission finds and concludes that it is inappropriate to include in rates an annual level of depreciation expense of $625,301 for the 2006 IT assets that were fully depreciated as of June 30, 2011. Instead, these assets should be removed from the general pool of computer equipment and receive special amortization, as recommended by the Public Staff. The Commission agrees with the Public Staff that since the IT assets have been updated through March 31, 2011, the unamortized balance of the 2006 IT assets as of March 31, 2011, which is $121,514, should be amortized over three years, resulting in an annual level of amortization expense of $40,505. As a result, depreciation expense will be reduced by $584,796 ($625,301 less $40,505). In addition, the Commission finds and concludes that the depreciation rate for Account 340.10 - Computer Equipment should be revised to be 25.48% to reflect the removal of these IT assets from the general pool of computer equipment. Accordingly, this revised depreciation rate results in a 0.25% reduction in the depreciation rate to be applied to the remaining IT assets and yields an additional decrease in depreciation of $10,467. This results in a total reduction of depreciation expense on IT assets of $595,263, which is appropriate for purposes of this proceeding.

Net Salvage Value for Plant Accounts

Aqua NC and the Public Staff disagreed on whether annual depreciation expense should include Aqua NC's proposed net salvage value for the water plant accounts for supply mains, distribution and transmission mains, and services and for the wastewater plant accounts for gravity mains, force mains, services, and outfall mains. However, in its Proposed Order, the Public Staff stated that although witness Furr had recommended that zero salvage value be included in the calculation of the depreciation rate for sewer outfall mains, witness Fernald did not make an adjustment to remove the net salvage value from depreciation expense for this account, due to the small dollar amount involved. Thus, the Public Staff, in essence, accepted the depreciation rate of 2.31% for Account 382 – Outfall Sewer Lines, as recommended by the Company.

The Public Staff asserted that is not appropriate to include in depreciation expense the net salvage value for the water plant accounts for Account 309 - Supply Mains, Account 331 - Distribution and Transmission Mains, and Account 333 - Services; and the wastewater plant accounts for Account 360 - Force Mains, Account 361 - Gravity Mains, and Account 363 - Services. The Public Staff recommended the removal of net salvage value, and proposed depreciation rates for these accounts as follows:

Account 309 – Water Supply Mains	1.59%
Account 331 – Water T&D Mains	1.28%
Account 333 – Water Services	1.75%
Account 360 – Sewer Force Mains	1.70%
Account 361 – Sewer Gravity Mains	1.70%
Account 363 – Sewer Services	1.87%

Aqua NC argued that the depreciation rates set forth in the depreciation study, calculated based on the net salvage value of replaced assets amongst other factors, are reasonable and appropriate for setting water and sewer rates in this proceeding and for the Company to use going forward; and they should not be subjectively modified, as proposed by the Public Staff. The Company recommended the following depreciation rates for these accounts:

Account 309 – Water Supply Mains	1.91%
Account 331 – Water T&D Mains	1.61%
Account 333 – Water Services	2.40%
Account 360 – Sewer Force Mains	2.00%
Account 361 – Sewer Gravity Mains	2.00%
Account 363 – Sewer Services	2.55%

In addressing the Public Staff's position on this issue, Company witness Spanos emphasized that service value means the cost of plant less net salvage. Net salvage is gross salvage, minus cost of removal. The NARUC Uniform System of Accounts for water utilities defines "service value" as the difference between the original cost and the net salvage value of utility plant. Witness Spanos explained that these particular plant accounts that Public Staff witness Furr proposed to carve out from the consistent treatment that the Public Staff otherwise does not oppose, do not have any attributes which would lead one to believe recovery should be different or that future customers should pay for the service value assets that they did not receive benefits from while in service. Witness Spanos testified that none of the definitions of depreciation suggest or imply special recovery practices for some accounts. Witness Spanos argued that the selective treatment by the Public Staff for these accounts is arbitrarily based on an apparent desire to reduce depreciation expense and not on sound ratemaking principles.

Witness Spanos pointed out a fairness issue. In particular, Aqua NC has never previously recorded net salvage amounts. Witness Spanos testified that one of the primary purposes of the depreciation study performed by Gannett Fleming for the Company was to establish proper recovery practices for the full service value of all assets and to begin implementation of the practice of recording the net salvage amounts to the accumulated depreciation account. Witness Spanos asserted that such approach will properly recover the full service value of the assets over the life of the assets. Witness Spanos emphasized that the recovery of the plant accounts witness Furr segregated should not be any different than all the other accounts.

Further, witness Spanos observed that the cost to abandon the assets in these accounts is not minor. The cost to abandon each of these assets may be minor as compared to removing the entire asset. Likewise, the cost to abandon is also minor as compared to installing the new asset. However, witness Spanos noted that the cost associated with abandonment needs to be compared to the cost of the asset being retired, which on average is going to be 50 to 70 years old. Further, witness Spanos testified that this amount is the end of life costs that needs to be associated with each asset and added as the full service value. Therefore, witness Spanos maintained that when considering the overall net salvage percent this amount is not minor, but imperative for establishing full recovery at the proper time.

In rebuttal testimony, witness Spanos explained that

> For example, assume Aqua [NC] installed 100 feet of distribution main in 1950 for $400 and retired the asset in 2020 (70 years) with a cost to abandon of $80. The net salvage percent is negative 20 percent and the full service value of the 100 feet of distribution main is $480. Based on all the definitions of depreciation, the full $480 should be recovered during the 70 years it is in service from the customers that enjoyed the service of the main, not the customers on the system after year 2020.

Witness Spanos advocated utilizing the net salvage percentage for depreciation accrual rates consistently with the new practice of recording the cost of removal as the most appropriate methodology. Therefore, according to witness Spanos, the cost of removal for each project will be charged to accumulated depreciation at the same time the Company accrues for the net salvage value in rates. Witness Spanos asserted that this consistent treatment properly assigns costs to those ratepayers receiving benefit for the asset while in service; this applies to all accounts. The net salvage value percentages supported by witness Spanos, as reflected in the depreciation study for the accounts in dispute, are as follows: for the water plant assets – supply mains, negative 15%; distribution and transmission mains, negative 20%; and services, negative 30%; and sewer plant assets – force mains, negative 15%; gravity mains, negative 15%; and services, negative 30%.

Witness Furr observed that the depreciation study recommended that the net salvage estimates for utility plant should be included as a depreciation expense. He explained that current utility customers would pay in rates as depreciation expense the costs to remove plant from service in future years. Witness Furr testified that the Public Staff does not believe current customers should pay in rates for salvage or plant abandonment and removal expenses which Aqua NC seldom or never incurs. He testified that the Public Staff had requested that Aqua NC provide the detailed records supporting the abandonment, disposal, and/or retirement for water plant assets – supply mains, distribution and transmission mains, and services; and sewer plant assets – force mains, gravity mains, services, and outfall lines. According to the Public Staff, Aqua NC responded that

> Abandonment Disposal, and/or retirement costs have not historically been identified and recorded for these categories. Total costs to remove and replace an existing asset are currently recorded against each WO (work order) that includes the activity to be capitalized along with the new asset.

Further, witness Furr testified that Aqua NC also could not provide to the Public Staff the field operations procedures that Aqua NC has used to abandon, dispose, and/or retire such plant assets. Witness Furr observed that all of these utility plant assets have long estimated useful lives; the depreciation study recommends for these utility plant assets useful lives of 50 to 70 years, with only outfall sewer lines at 35 years.

Furthermore, witness Furr stated that Aqua NC has not provided historical cost data from its North Carolina operations to support abandonment, salvage, and retirement costs for these plant assets. Witness Furr testified that the cost to abandon each of the plant items specified should be minor. He explained that the water mains and services would usually be abandoned in place underground with the only costs being to dig a limited number of holes and to plug the lines in a limited number of locations. He stated that similar field procedures would be used for the sewer mains and services plus line flushing. Additionally, witness Furr testified that if a city, town, or county were to purchase a water or sewer system from Aqua NC, the utility plant assets purchased and conveyed to the city, town, or county would primarily be the items for which the Public Staff has recommended removal of net salvage value from the depreciation rates, being the water distribution and transmission mains, and services; and the sewer force mains, gravity mains, and services. He observed that the acquiring city, town, or county would normally perform the very limited disconnecting of the gravity or force main leading to the wastewater treatment plant, with Aqua NC incurring very little cost, if any.

However, witness Furr explained that the Public Staff does not oppose the remaining net salvage expense included in depreciation rates for other plant accounts in the depreciation study as Aqua NC has in the past removed from service - wells, hydropneumatic water storage tanks, pumps, blowers, meters, etc., and these assets are not utility system assets normally purchased by cities, towns, and counties.

Further, upon cross-examination, witness Furr testified that the Public Staff does not disagree with the concept of net salvage value, but does not agree with the net salvage value assigned to these particular asset classes at issue here. He explained that the percentage assigned assumes they have costs associated with abandonment. The Public Staff has assigned a zero net salvage value to these six plant assets.

Based upon the foregoing, the Commission is of the opinion that the depreciation rates, set forth in the depreciation study, calculated for the water plant accounts for supply mains, distribution and transmission mains, and services and for the wastewater plant accounts for gravity mains, force mains, services, and outfall mains based on the salvage value of replaced assets, are a reasonable and appropriate basis for setting water and sewer rates in this proceeding and for the Company to use going forward.

As reported in the depreciation study, the net salvage value considerations are as follows:

> The estimates of net salvage were based primarily on judgment which considered a number of factors. The primary factors were the knowledge of management's plans and operating policies; and net salvage estimates from other water and wastewater companies. The net salvage estimates are expressed as a percent of the original cost of plant retired. The net salvage estimate for general plant accounts with amortization accounting implemented will be zero percent.

Gannett Fleming is a known and reputable third-party. They are widely considered experts in this field. They were selected by Aqua NC and endorsed by the Public Staff to perform the depreciation study, which was required by Commission Order[1] issued on April 8, 2009, in Docket No.W-218, Sub 274.

Aqua NC cannot be expected to provide detailed records on the costs of removal of mains as most of Aqua NC's mains are of such recent vintage that extensive retirement activity has not yet occurred. Likewise, Aqua NC has no significant history of sales to municipalities so as to support the assumption that future retirements may not occur.

The Commission agrees with the Company that utilizing the net salvage percentage for depreciation accrual rates consistently with the new practice of recording the cost of removal is the most appropriate methodology. The Commission understands that by using this methodology, the cost of removal for each project will be charged to accumulated depreciation at the same time the Company accrues for the net salvage in rates. This treatment properly assigns costs to those ratepayers receiving benefit for the asset while in service and properly applies to all accounts. Therefore, the Commission finds and concludes that the following depreciation rates, as set forth in the depreciation study, calculated based on the salvage value of replaced assets, are reasonable and appropriate water and sewer rates for use in this proceeding:

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[1] In that Order, the Commission required that Aqua NC file a depreciation study with the Commission before filing another general rate case; and it found that the depreciation rates previously established by the Commission should not be changed until such a depreciation study is filed and the new rates are allowed, as stipulated. In that docket, Public Staff "Witness Fernald stated that in some instances, the Company had changed its depreciation lives or used different depreciation lives without filing a depreciation study or rate case with the Commission." As a result, witness Fernald testified that the Company should file a depreciation study before its next general rate case. That recommendation was agreed to in the Joint Stipulation entered between the Company, the Public Staff, and the Ad Hoc Water and Sewer Users Group. The Commission approved the Joint Stipulation.

Account 309 – Water Supply Mains	1.91%
Account 331 – Water T&D Mains	1.61%
Account 333 – Water Services	2.40%
Account 360 – Sewer Force Mains	2.00%
Account 361 – Sewer Gravity Mains	2.00%
Account 363 – Sewer Services	2.55%

Summary

Based upon the foregoing, the Commission finds and concludes that the appropriate level of depreciation and amortization expense for the combined operations for use in this proceeding is $6,530,688. The Commission also finds and concludes that the depreciation rates set forth in the Gannett Fleming depreciation study are a reasonable and appropriate basis for setting water and sewer rates in this proceeding and are proper for the Company to use in booking depreciation expenses going forward, except for the depreciation rate of 25.73% for the computer equipment account (Account 340.10), which should be revised to be 25.48%.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 53 THROUGH 55

The evidence supporting these findings of fact is contained in the testimony of Public Staff witness Fernald and Company witnesses Becker and Roberts. The following table summarizes the differences between the Company's level of other taxes and Section 338(h) adjustment from its application and the amounts recommended by the Public Staff:

Item	Company Application	Public Staff	Difference
Property taxes	$ 488,835	$ 488,835	$ 0
Payroll taxes	778,833	578,056	(200,777)
Other taxes	219	219	0
Section 338(h) adjustment	(171,915)	(171,915)	0
Total	$1,095,972	$ 895,195	$ (200,777)

As shown above, the Company and the Public Staff disagreed on the level of payroll taxes. With the revisions made by the Public Staff in its supplemental testimony filed on June 7, 2011, and Revised Fernald Exhibit I filed on June 30, 2011, the Company does not dispute the following Public Staff adjustments to payroll taxes:

Item	Amount
Reflect Company update to payroll taxes	($171,964)
Adjust percentage charged to expense by NC employee	(1,582)
Adjust stock option expense for NC employees	(717)
Adjust restricted stock expense for NC employees	(1,192)
Remove time spent on acquisitions by corporate	(269)
Adjust ACO allocation factor	(3,275)
Reflect changes in ACO employees since 7/31/10	590
Total	($178,409)

Therefore, the Commission finds and concludes that the adjustments listed above, which are not contested, are appropriate adjustments to be made to payroll taxes in this proceeding.

Based on the testimony of Company witnesses Becker and Roberts, the Company disagreed with the following Public Staff adjustments to payroll taxes:.

Item	Amount
Reflect new hires and terminations since 5/26/11	$ 2,014
Remove open positions	(6,197)
Reflect hours worked for twelve months ended 3/31/11	(10,127)
Remove time spent on nonutility work and acquisitions	(5,448)
Adjust corporate executive compensation	(2,610)
Total	($22,368)

However, in Aqua NC's Proposed Order, the Company stated that Fernald Exhibit I, Schedule 3-2(a) REVISED, filed on June 30, 2011, reflects adjustments consistent with the Company's current authorized headcount of 171, less its historical average of three open positions. Therefore, the Commission finds and concludes that the adjustments listed above to reflect new hires and terminations since May 26, 2011, and to remove open positions are no longer contested issues between the Public Staff and Aqua NC. Consequently, the Commission finds and concludes that these two adjustments, which are based on the payroll tax percentage of 7.62% agreed to by the Public Staff and the Company, are appropriate adjustments to be made to payroll taxes in this proceeding.

Capitalization Percentage

As previously discussed in this Order, the Commission has concluded that the Public Staff's adjustment to decrease salaries by $132,904 to reflect the hours worked as of March 31, 2011 is appropriate and should be made in this proceeding. Therefore, the Commission finds and concludes that it is appropriate to also decrease payroll taxes by $10,127 based on the payroll tax percentage of 7.62% agreed to by the Public Staff and the Company.

Time Spent on Nonutility Work and Acquisitions

As previously discussed in this Order, the Commission has concluded that the Public Staff's adjustment to decrease salaries by $71,491 to remove time spent on nonutility work and acquisitions is appropriate and should be made in this proceeding. Therefore, the Commission finds and concludes that it is appropriate to also decrease payroll taxes by $5,448 based on the payroll tax percentage of 7.62% agreed to by the Public Staff and the Company.

Executive Compensation

As previously discussed in this Order, the Commission has concluded that the Public Staff's adjustment to remove 50% of the compensation for four top executives is inappropriate and instead has concluded that the removal of 25% of the compensation for four top executives is appropriate. Therefore, it is appropriate to also remove 25% of the payroll taxes for these executives, resulting in a decrease in payroll taxes of $1,304.

Summary

Based upon the foregoing, the Commission concludes that the appropriate level of payroll taxes for Aqua NC's combined operations for use in this proceeding is $579,361, composed of the following:

Aqua Water	$384,585
Aqua Sewer	115,285
Fairways Water	13,139
Fairways Sewer	12,138
Brookwood Water	54,214
Total Combined Operations	$579,361

Further, the Commission finds and concludes that the appropriate level of property taxes, other taxes, and Section 338(h) adjustment for Aqua NC's combined operations for use in this proceeding is $317,139, consisting of property taxes of $488,835, other taxes of $219, and a reduction of $171,915 for the Section 338(h) adjustment. The $317,139 for the combined operations is composed of the following:

Aqua Water	$250,091
Aqua Sewer	(24,734)
Fairways Water	43,724
Fairways Sewer	794
Brookwood Water	47,264
Total Combined Operations	$317,139

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 56 THROUGH 61

The evidence supporting these findings of fact is contained in the testimony of Public Staff witness Fernald and Company witnesses Becker and Szczygiel.

The following table summarizes the differences between the Company's level of regulatory fee, gross receipts tax, and income taxes from its application and the amounts recommended by the Public Staff:

Item	Company Application	Public Staff	Difference
Regulatory fee	$ 53,215	$ 53,249	$ 34
Gross receipts tax	1,989,334	1,951,621	(37,713)
State income taxes	272,048	582,927	310,879
Federal income taxes	1,284,739	2,723,014	1,438,275
Total	$3,599,336	$5,310,811	$1,711,475

Regulatory Fee

The difference in the level of regulatory fee is due to the differing levels of revenues recommended by the Company and the Public Staff. Based on conclusions reached elsewhere in this Order regarding the levels of revenues and the statutory rate of 0.12%, the Commission concludes that the appropriate level of regulatory fee for use in this proceeding is $55,942, composed of the following:

Aqua Water	$35,602
Aqua Sewer	11,945
Fairways Water	1,202
Fairways Sewer	1,250
Brookwood Water	5,943
Total Combined Operations	$55,942

Gross Receipts Tax

The difference in the level of gross receipts tax is due to (1) the Public Staff's adjustment to remove gross receipts tax on revenues which are not subject to the tax, and (2) the differing levels of revenues recommended by the Company and the Public Staff. Public Staff witness Fernald testified that the Public Staff did not include in its calculation of gross receipts tax (1) rental income from antenna leases; (2) amortization of gains and losses; and (3) nonutility revenues since these items are not subject to gross receipts tax. The Company did not contest the Public Staff's adjustment to gross receipts tax for items not subject to the tax. The Commission concludes that it is appropriate to remove gross receipts tax on these revenues since they are not subject to gross receipts tax. Based on conclusions reached elsewhere in this Order regarding the levels of revenues which are subject to gross receipts tax, and the statutory rates of 4% for water operations and 6% for sewer operations, the Commission finds and concludes that the appropriate level of gross receipts tax for use in this proceeding is $2,049,429, composed of the following:

Aqua Water	$1,164,715
Aqua Sewer	596,447
Fairways Water	37,679
Fairways Sewer	62,472
Brookwood Water	188,116
Total Combined Operations	$2,049,429

State Income Tax

The difference in the level of state income taxes is due to the differing levels of revenues and expenses recommended by the Company and the Public Staff. Based on conclusions reached elsewhere in this Order regarding the levels of revenues and expenses, the Commission concludes that the appropriate level of state income taxes for use in this proceeding is $685,015, composed of the following:

Aqua Water	$455,320
Aqua Sewer	133,566
Fairways Water	12,703
Fairways Sewer	15,827
Brookwood Water	67,599
Total Combined Operations	$685,015

Federal Income Tax

The difference in the level of federal income taxes is due to (1) the difference between the Company and the Public Staff concerning the amount to deduct in calculating federal income taxes for the domestic production facilities deduction, and (2) the differing levels of revenues and expenses recommended by the Company and the Public Staff.

Company witness Szczygiel and Public Staff witness Fernald presented testimony regarding the domestic production activities deduction (DPAD or Section 199 deduction).[1]

In a nut shell, businesses with "qualified production activities" can take a tax deduction associated with those activities. According to the witnesses, a water utility, in determining taxable income for federal income tax purposes, can take a deduction related to the production of potable water. Such production includes the acquisition, collection, and storage of raw water, as well as the transportation of water to a treatment facility and the treatment of water at that facility. Under Section 199, the deduction is a percentage of the lesser of (1) income attributable to the production of potable water or (2) taxable income for the year. The deduction percentage in 2009 was 6% and increased to 9% in 2010.

On rebuttal, Company witness Szczygiel testified that "the [DPAD] is a tax credit that companies are permitted to use to offset, to the extent allowed, taxable income." He also testified that "[u]nlike a tax deduction, this credit is a dollar for dollar reduction of taxes due; however it can only be used to the extent there is taxable income to be offset and the credit cannot be carried forward or backward if not fully utilized."

Company witness Szczygiel testified further as follows:

[1] Witnesses Szczygiel and Fernald referred to the present deduction as a "facilities" deduction. However, as Internal Revenue Code (IRC) Section 199 does not appear to provide for a domestic production "facilities" deduction but rather an "activities" deduction, the Commission, for purposes of this discussion, has elected to adhere more precisely to the terminology contained in the IRC, in the interest of clarity.

> The Section 199 . . . deduction should not be considered in the North Carolina rate case for the following reason: the Section 199 deduction . . . is based on the lesser of the qualified production activities income or taxable income on a consolidated basis. The consolidated Aqua America, Inc. federal tax returns for 2010, 2011, 2012, and possibly 2013 will produce a net operating loss, thereby eliminating any Section 199 deduction for all companies included in the consolidated return. The Company will reflect consolidated qualified production activities income in the above mentioned years, but due to the taxable income limitation, will not have a deduction related to Section199.
>
> Even on a standalone basis, Aqua North Carolina will incur a net operating loss in 2011 and 2012, thereby eliminating the Section 199 deduction.
>
> Our major concern, simply stated, is this: if the Company does get this deduction, why should Aqua NC's revenue requirement be reduced by this credit that cannot be utilized due to having a taxable net loss?

The Public Staff argued that the Section 199 deduction is not a tax credit, per se, but rather, is a tax deduction to be taken in determining taxable income for federal income tax purposes; and, as such, does not represent a dollar-for-dollar reduction of a company's actual income tax liability, as argued by Company witness Szczygiel.

Public Staff witness Fernald testified that Aqua NC, itself, treated the Section 199 deduction as a "deduction" in its calculation of the appropriate level of federal income tax expense proposed by the Company for inclusion in the Company's North Carolina jurisdictional test-period cost of service; as reflected in Aqua NC's application for a general rate increase.

The Public Staff further contended that Aqua NC will not know whether it will have taxable losses for 2011, 2012, and 2013 until those years have ended and the tax returns have been completed.

The Public Staff further opined that the Commission, for ratemaking purposes, bases income tax expense on the adjusted test-period level of revenues and expenses and the applicable tax rate for utility operations. The Public Staff stated that the federal income tax rate applicable to Aqua NC's utility operations is 35%; and that the Company used that rate to calculate the level of federal income tax expense it proposed for inclusion in Aqua NC's proposed test-period cost of service for purposes of this proceeding. Therefore, in view of the foregoing and in consideration of the fact that a tax rate of 35% is or will be used to establish rates — according to the Public Staff — the Public Staff is of the opinion that it is appropriate to include the Section 199 deduction in determining the level of federal income tax expense properly includable in the test-period cost of service.

In consideration of the foregoing, the Public Staff recommended that a Section 199 deduction of $85,246, based upon the 2010 deduction rate of 9%, be adopted for use by the Commission in the present regard.

The Commission agrees with the Public Staff that the Section 199 deduction is not a tax credit, per se, but rather, is a tax deduction to be taken in determining taxable income for federal income tax purposes. Moreover, although Company witness Szczygiel might appear to have been inadvertent — in certain instances — due to his use of the terms "tax credit" and "tax deduction" interchangeably, the Commission is of the opinion that he is and was aware of the difference.

However, the foregoing aside, the crux of the issue to be resolved by the Commission in this instance is this: Based upon the test-period level of operations and other evidence and information of record, should a Section 199 deduction be included, by the Commission, in determining Aqua NC's taxable income for federal income tax purposes — and consequently the appropriate level of federal income tax expense to be included in the Company's test-period cost of service — for purposes of this proceeding? The Public Staff has argued that the Commission should do so. The Company has argued that the Commission should not. After having carefully considered this matter, the Commission is of the opinion, and so finds and concludes, that the preponderance of the evidence supports the position taken by the Public Staff.

The Commission has reached the foregoing conclusion, in large measure, in consideration of the following: (1) that Aqua NC, itself, in its application, included the Section 199 deduction in its calculation of the appropriate level of federal income tax expense it proposed for inclusion in the test-period cost of service; (2) that, for tax year 2009, the most recent year for which actual information of record is available, it appears that Aqua NC had a level of taxable income that was far more than adequate to allow it to utilize a Section 199 deduction comparable to that proposed by Public Staff witness Fernald[1]; and (3) that, although Aqua NC witness Szczygiel testified that the Company would experience net operating losses in tax years 2011 and 2012 — on a standalone basis — and that Aqua America, Inc. would experience such losses for 2010, 2011, 2012, and possibly 2013 — on a consolidated basis, his testimony was not persuasive; particularly in consideration of the fact that he offered no explanation or other justification in support of the validity or reasonableness of the Company's aforementioned tax-loss expectations.[2]

[1] This finding is based upon information contained in Aqua NC's 2009 North Carolina state income tax return, including "add-back" provisions.

[2] To avoid any misperception that might otherwise exist, it is observed that, absent clear and compelling evidence to the contrary — and no such evidence has been presented in this proceeding — the Commission is of the opinion that the level of income tax expense properly includable in the rates of any given jurisdictional utility should be based solely upon that utility's taxable income determined on a standalone basis; and without regard to the taxable income of a controlled group of companies, under a common parent, determined on a consolidated basis. The Commission is of that view because it is of the opinion, generally speaking, that it is inappropriate for a regulated utility to be advantaged or disadvantaged, from the standpoint of the level of income tax expense properly includable in its cost of service, due to the fact that it is one of two or more connected corporations (parent-subsidiary, brother-sister, or combined companies) controlled by a common parent. For example, in the Commission's view, it would be inappropriate for a utility's tax expense to be <u>increased</u> because a tax deduction — which would have been available on a standalone basis — was not available on a controlled-group, consolidated basis because of the absence of consolidated taxable income; just as it would be equally inappropriate for a utility's tax expense to be <u>decreased</u> because of a tax loss incurred by an unregulated affiliate (i.e., a brother, sister, or parent corporation within a controlled group) or, for that matter, due to a tax loss having been incurred by an unregulated business segment of the regulated utility.

Accordingly, in consideration of the foregoing and the entire record of this proceeding, the Commission finds and concludes that it is appropriate to include a Section 199 deduction of $85,246 in determining the appropriate level of federal income tax expense properly includable in Aqua NC's test-period cost of service for purposes of this proceeding, as advocated by the Public Staff.

Summary

Based on conclusions reached elsewhere in this Order regarding the levels of revenues and expenses, the domestic production facilities deduction of $85,246, and the corporate rates of 6.9% for state income taxes and 35% for federal income taxes, the Commission concludes that the appropriate level of federal income taxes for use in this proceeding is $3,205,122, composed of the following:

Aqua Water	$2,127,708
Aqua Sewer	630,760
Fairways Water	58,560
Fairways Sewer	74,742
Brookwood Water	313,352
Total Combined Operations	$3,205,122

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 62 THROUGH 65

The evidence supporting these findings of fact is contained in the testimony and exhibits of Company witnesses Ahern and Roberts and Public Staff witness Hinton.

The Public Staff and Aqua NC both recommended the use of a hypothetical capital structure for ratemaking purposes. In prefiled direct testimony, Company witness Ahern recommended a hypothetical capital structure consisting of 50% long-term debt and 50% common equity. In prefiled direct testimony, Public Staff witness Hinton recommended the use of a hypothetical capital structure consisting of 53.07% long-term debt and 46.93% common equity.

Company witness Ahern testified that a capital structure containing 50% long-term debt and 50% common equity is consistent with the historical capital structures maintained, on average, by the water utility industry, and adopted or approved by the Commission in recent Aqua NC proceedings.

Witness Ahern testified that a capital structure containing 50% long-term debt and 50% common equity was reflected in her proxy group of nine comparable water companies as well as witness Hinton's group of eight comparable water utilities. The Commission notes that witnesses Ahern and Hinton both used the same eight companies, with witness Ahern adding Aqua America to her group. Ahern Exhibit 1, Schedule PMA-5, shows that witness Ahern's proxy group maintained an average long-term debt ratio of 50.01% for the five years ending 2010, which encompassed the time periods of the Company's last three rate settlements. Likewise, as shown on Ahern Exhibit 2, Schedule PMA-1R, the proxy group selected by witness Hinton maintained an average long-term debt ratio of 50.32% for the five years ending 2010.

Company witness Ahern argued that the Commission's adoption of the last three rate settlement agreements and approval of the issuance of an unsecured loan from Aqua America, Inc., in Docket No. W-218, Sub 320, "indicate the Commission's tacit approval of a hypothetical 50.00% long-term debt and 50.00% common equity ratio for ratemaking purposes for Aqua NC." Witness Ahern acknowledged that settlement agreements are not binding. On cross-examination, she acknowledged that in the recent Commission Order Granting Approval of Long-Term Debt Agreement for Aqua NC in Docket No. W-218, Sub 320, the Commission did not approve a capital structure. Witness Ahern further testified that the Commission did not approve capital structures in prior Aqua NC debt-issuance approval orders.

Aqua NC asserted that, while settlement agreements are not binding on the Commission, they are subject to Commission approval and indicate past Commission acceptance of a hypothetical 50% long-term debt and 50% common equity ratio for establishing rates for Aqua NC.

Public Staff witness Hinton testified that he initially considered using the capital structure of Aqua NC and the consolidated capital structure of Aqua America. Witness Hinton testified that "Aqua North Carolina has made an attempt to keep 50-50 capital structure ratios on its books," and conceded that "the Commission accepted those as reasonable." However, Aqua NC's past practices of converting short-term debt to equity prompted him to question the reasonableness of the reported balances of debt and equity.

Witness Hinton testified that Aqua America tends to propose a 50% long-term debt and 50% common equity capital structure for its subsidiaries in proceedings in various other states. Such was the case illustrated in cross-examination of Company witness Ahern regarding her recommended hypothetical capital structure consisting of 50% long-term debt and 50% common equity in a recent petition before the Indiana Utility Regulatory Commission to increase the rates for Utility Center, Inc., d/b/a Aqua Indiana, Inc., a subsidiary of Aqua America (Cause No. 43874), where the Indiana Utility Regulatory Commission by Order dated April 13, 2011, approved the parent Aqua Indiana's actual capital structure of 51.11% debt and 48.89% equity.

Witness Hinton testified that Aqua NC's propensity to propose 50% long-term debt and 50% common equity capital structure in other states caused him to question whether the balances reflect real balances of common equity and real debt, especially when Aqua America's filings with the Securities and Exchange Commission (SEC) reflect a significantly higher ratio of long-term debt.

On examination by the Commission, witness Hinton testified that Aqua America's 2010 year-end consolidated financial statements filed with the SEC reported a capital structure consisting of 57% long-term debt and 43% common equity. In response to questions from the Commission, witness Hinton testified that in response to a data request for the debt and common equity balances for Aqua America, the Public Staff was provided with a capital structure for Aqua America of 54.80% long-term debt and 45.20% common equity. Witness Hinton further testified that the Standard & Poor's (S&P) report attached to his testimony reported a 58% ratio of long-term debt because the S&P analysts have a skill set that allows for the addition or deduction of debt as part of their analysis.

Witness Hinton asserted that Aqua America exercises "an extreme amount of parental control" over the capitalization of Aqua NC. He stated, "they have the ability to at the stroke of a pen change debt into equity."

Witness Hinton contended that his recommended common equity ratio of 46.93% was based on the average common equity ratio for his group of eight water utilities listed on witness Hinton's Exhibit JRH-4, which he considered to be comparable in risk to Aqua NC and Aqua America.

Upon cross-examination, witness Hinton acknowledged that he had used data from the April 2011 AUS Utility Reports to calculate a 46.93% equity share of capitalization. In Company witness Ahern's prefiled rebuttal testimony, she testified that she was the publisher of those reports and the 46.93% common equity percentage was based on a capital structure that included common equity, long-term debt, and short-term debt. She further testified that if short-term debt was removed and a common equity percentage calculated, the equity percentage would be 49.58%.

After conceding that his equity ratio was based on a capital structure that included short-term debt, witness Hinton noted the various methods one can utilize with a hypothetical capital structure based on industry averages. Witness Hinton explained that if he had included Aqua America in the group of water utilities, his recommended capital structure without short-term debt would have included 48.82% common equity. Upon further cross-examination, witness Hinton agreed that a 49.58% common equity ratio identified by witness Ahern and the previously stipulated Aqua NC rate cases capital structures with a 50% common equity ratio were at the upper end of reasonableness and were not totally unreasonable.

In Docket No. W-218, Sub 320, Aqua America has pushed down debt to Aqua NC in an attempt to maintain a 50% common equity ratio. This effort to push down debt was in response, in part, to the conversion of debt to common equity that resulted from the acquisition adjustment when Aqua America purchased Heater. However, as stated in the Order dated December 21, 2010 approving Aqua NC's most recent debt refinancing in Docket No. W-218, Sub 320, the approval of the long-term debt agreement in that case does not restrict the Commission in any future rate proceedings.

In this case, Aqua America clearly controls the capital structure of Aqua NC, as evidenced by Aqua America's pushdown of debt to Aqua NC and Aqua America's conversion of Aqua NC debt to equity.

Witness Hinton testified that 98% of Aqua America's total revenues are derived from regulated water and sewer utility operations. He further testified that virtually all of Aqua America's subsidiaries in other states are in the water and wastewater business and are regulated by a state regulatory commission.

In this proceeding, the parties could not reach an agreement regarding capital structure that was mutually satisfactory. The Commission concludes that prior Commission approval of settlements between the Company and the Public Staff is not binding on future rate cases, and prior Commission approval of pushdowns of debt capital from the parent company Aqua America is not determinative in establishing the appropriate capital structure in this proceeding.

The evidence in this docket shows that a capitalization ratio near 50% long-term debt and 50% common equity are both typical and reasonable for water and sewer utilities. The Commission understands that capitalization structures can change abruptly with major events and then return to equilibrium. The issuance of new debt or equity can alter a capital structure in the near term. However, the Commission also sees significant variations in capital structures among water companies in the proxy groups in the record in this docket, as shown in Ahern Rebuttal Exhibit 2, Schedule PMA-1R. It is therefore not clear how much weight should be put on average five-year capital structures of these proxy groups.

As Aqua America can convert Aqua NC's short-term debt into common equity by changing its capitalization policy, the Commission is disinclined to rely upon actual company capitalization ratios. Witness Hinton testified that Aqua America's subsidiaries are regulated water companies. Aqua America exercises significant control over the capital structure of its subsidiaries. The record in this docket shows that Aqua America generally maintained a significantly higher percentage of long-term debt than its subsidiaries. Debt is cheaper than equity. The ability of the parent company to obtain debt and convert it to equity at the subsidiary level where it will earn a considerably higher return in this context persuades the Commission to adopt a hypothetical capital structure.

The Commission notes that the pushdown of debt from Aqua America to Aqua NC in Docket No. W-218, Sub 320 happened in response to the equity portion of the capital structure of Aqua NC increasing as a result of the Heater acquisition. The Public Staff agreed to and the Commission accepted a pushdown of debt that resulted in a 50% equity share in that docket. However, as agreed to by witness Ahern on cross-examination, nowhere in that December 21, 2010 Order does it mention a capital structure or approval of any capital structure.

Witness Hinton proposed a hypothetical capital structure that more closely resembled Aqua America's capital structure. However, witness Ahern challenged witness Hinton's proposed capital structure, demonstrating that it was based on an erroneous assumption.

Aqua NC has recently gained the ability to borrow funds at significantly below market rates from the North Carolina State Revolving Fund (SRF). This source of capital with its below market interest rates, which has not been previously available to the Company, should assist the company in earning its authorized return without necessitating an infusion of equity.

Having carefully considered all of the evidence in this record, the Commission finds and concludes that the appropriate capital structure for ratemaking purposes in this case consists of 50.42% long-term debt and 49.58% common equity. These are the ratios from the accurate assessment of the average common equity ratios from the group of eight water utilities. This balance of equity to debt is close to Aqua NC's proposed capital structure, but recognizes the issues raised by the Public Staff. It represents a reasonable balance of the various hypothetical ratios of common equity that have been placed into evidence.

Company witness Ahern recommended a 5.53% embedded cost of long-term debt as of July 31, 2010. Public Staff witness Hinton recommended a 5.56% cost of long-term debt as of December 31, 2010. Given that the December 31, 2010 embedded cost of debt for Aqua NC is more current and, therefore, more representative of the cost of debt at the close of the hearing, the Commission finds and concludes that the appropriate cost of debt is 5.56%, which is slightly greater than the embedded cost of debt of 5.53% originally proposed by Aqua NC.

Aqua NC and the Public Staff were not in agreement on the appropriate cost of common equity. Company witness Ahern recommended that the Commission recognize 11.00% as cost of common equity. Public Staff witness Hinton recommended 9.80% as the cost of common equity.

Company witness Roberts testified that Aqua NC has achieved the following returns on equity in the last four years:

	Return on Equity
2007	0.60%
2008	-3.60%
2009	-1.90%
2010	4.20%

He further testified that, during the test period ending July 31, 2010, Aqua NC had a return on common equity of 1.69% for water operations and 1.88% for wastewater operations.

Witness Ahern testified that because Aqua NC's common stock is not publicly traded, a market-based common equity cost rate cannot be determined directly for the Company. Consequently, in arriving at her recommended common equity cost rate of 11.00%, she assessed the market-based common equity cost rates of companies of relatively similar risk for insight into a recommended common equity cost rate applicable to Aqua NC and suitable for ratemaking purposes.

Witness Ahern employed a three-step process to determine a cost of equity capital. First, she chose a nine-company proxy group of comparable water companies. Her proxy group included Aqua NC's parent company, Aqua America. She then employed three commonly used models to determine the group's average return on equity. Her second step was to select a proxy group of 42 non-price-regulated companies of comparable risk and to apply the same three models to that group, as well as a Comparable Earnings Analysis. From the results of her analysis of the nine-company water proxy group and the 42 company non-price-regulated group, she determined an "indicated" cost of common equity for Aqua NC. Her third step was to adjust that indicated cost of equity capital for financial risk, flotation costs, and business risks on the grounds that no proxy group can be selected to be identical in risk to Aqua NC and, therefore, a proxy group's results must be adjusted to reflect the unique relative financial and/or business risk of the Company.

Witness Ahern employed three different models in her cost of equity analyses: the Discounted Cash Flow (DCF) Model, the Risk Premium Model (RPM), and the Capital Asset Pricing Model (CAPM). In layman's terms, the DCF model takes the projected dividends that an equity investor will receive and calculates the discount rate that will make those dividends equal to the investor's equity investment. The discount rate is the cost of equity capital. The RPM attempts to capture the additional risk premium of an equity investment relative to a long-term debt investment. The CAPM assumes that all business risk can be diversified away and focuses on systemic risk, or the relative variation in price between the company's stock and the market in general. The CAPM adds a risk-free rate of return to a market risk premium, which is adjusted proportionately to reflect the systematic risk of the individual company relative to the total market. Systemic risk is measured by Beta. Witness Ahern used both the Traditional and Empirical CAPM. The Empirical CAPM method is the result of researchers applying the CAPM to historical data and noting that the results are not exactly what the CAPM predicted. An adjustment is calculated and used in the Empirical CAPM. In using all of these models, assumptions must be made.

Witness Ahern applied the DCF model to the group of nine utility water companies. She relied exclusively on analyst's forecasts of earnings per share (EPS) as reported by Value Line Investment Survey (Value Line) and consensus estimates of EPS by analysts as compiled by Reuters, Zack's, and Yahoo Finance. The results of her DCF analysis indicated a cost of equity of 9.21% as shown in Ahern Exhibit 1, Schedule PMA-6.

Witness Ahern employed an RPM analysis that she referred to as the "Adjusted Total Market Approach." In order to estimate the Beta-Adjusted Equity Risk Premium, witness Ahern averaged the historical arithmetic mean rate of return and the forecasted Value Line market returns. She then averaged that result with an equity risk premium based on holding-period returns, arriving at a 4.32% equity risk premium that she combined with a prospective bond yield to produce her Adjusted Total Market result of 10.49% shown in Ahern Exhibit 1, Schedule PMA-8, Page 1.

The third approach used by witness Ahern incorporated the Traditional and Empirical versions of the CAPM applied to her nine water-company proxy group. Witness Ahern relied upon forecasted yields on 30-year treasury securities to estimate the risk-free rate. Witness Ahern then relied upon historical Arithmetic Mean Returns of 11.90%, as reported by Ibbotson Associates, Inc., minus a 5.20% return on US Government securities to arrive at 6.70% expected market premium. The 6.70% is averaged with her second method involving a forecasted total market return of 12.53% using data from Value Line minus a risk-free rate of 4.88% to estimate an alternative market premium of 7.65%, as shown on Ahern Exhibit 1, Schedule PMA-10, Page 2. Witness Ahern then averaged her two market premiums of 6.70% and 7.65% to arrive at a 7.18% market premium. With the use of the Value Line Beta coefficient, her estimates of the risk-free rate, and the market premium, she produced two CAPM results which produced a median cost of equity of 10.18%, as shown on Ahern Exhibit 1, Schedule PMA-10, Page 1.

Witness Ahern also selected what she described as a proxy group of 42 non-price-regulated companies of comparable risk. She analyzed the cost of equity capital for that 42-company group with a Comparable Earnings Analysis that used projected five-year returns on book common equity. The analysis produced a proxy group average cost of equity. She also applied the DCF model, the RPM, and the CAPM to the same group.

Witness Ahern testified that the Comparable Earnings method is consistent with the landmark United States Supreme Court case of Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944). Her analysis of the 42 comparable risk non-price-regulated companies yielded a 14.50% return on common equity as shown in Ahern Exhibit 1, Schedule PMA-12, Page 1.

Witness Ahern then applied a DCF model, an RPM analysis, and a CAPM to that same group of 42 comparable risk non-price-regulated companies, as shown on Ahern Exhibit 1 Schedule PMA-13. The median of her DCF cost of equity capital analyses was 12.37%. Her RPM analysis yielded a cost of equity capital of 11.31%. Using the CAPM and Empirical CAPM methods, she calculated the company-by-company median for both methods and averaged the results for an indicated common equity cost of 10.49%. She then averaged the results of her three models, 12.37%, 11.31%, and 10.49%, to get an 11.39% return on common equity. Witness Ahern then averaged the 14.50% estimate from her Comparable Earnings Analysis together with the averaged result of 11.31% from her three models to yield a 12.95% return on common equity based on her group of 42 non-price-regulated companies, as shown on Ahern Exhibit 1, Schedule PMA-11, Page 1.

Witness Ahern's DCF, RPM, and CAPM analyses of her nine-company water proxy group yielded equity cost rates of 9.21%, 10.49%, and 10.18%, respectively. Her evaluation of her 42-company comparable risk, non-price-regulated proxy group yielded an equity cost rate of 12.95%. After reviewing the cost rates she had calculated, she chose an indicated cost of equity of 10.65% for Aqua NC in this docket, before adjustments for financial and business risks and flotation costs.

Witness Ahern testified that no proxy group can be selected to be identical in risk to Aqua NC. Therefore, the proxy group's results must be adjusted to reflect the unique relative financial and/or business risk of the Company. She testified that the 10.65% indicated cost of equity needed to be adjusted for financial and business risks and for the flotation costs necessary in the issuance of common stock. She recommended a downward adjustment of eight basis points to reflect the lower risk incurred by Aqua NC due to its greater percentage of equity in its capital structure in comparison to the nine-company proxy water group. She recommended a 19 basis-point increase to cover flotation costs. Finally, she recommended a 25 basis-point increase to reflect her assessment of greater business risk, due largely to Aqua NC's relatively smaller size. With these adjustments and rounding, witness Ahern recommended a common equity cost rate of 11.00%.

The results of witness Ahern's various analyses can therefore be summarized as follows:

Proxy Group of Nine Water Companies:

Discounted Cash Flow Model	9.21%
Risk Premium Model	10.49%
Capital Asset Pricing Model	10.18%
Average of DCF, RPM, & CAPM	9.96%

Proxy Group of 42 Comparable Risk, Non-Price-Regulated Companies:

Comparable Earnings Analysis (CEA)	
Median	15.00%
Conservative Median (3 outliers omitted)	14.50%
Discounted Cash Flow Model - Median	12.37%
Risk Premium Model	11.31%
Capital Asset Pricing Model	10.49%
Average of DCF, RPM, & CAPM	11.39%
Average of Conservative CEA (14.50%) & the Average of DCF, RPM, & CAPM (11.39%)	12.95%
Indicated Common Equity Cost Rate:	10.65%
Financial Risk Adjustment	(0.08)
Flotation Cost Adjustment	0.19
Business Risk Adjustment	0.25
Indicated Common Equity Cost Rate after Adjustment For Financial & Business Risks	11.01%
Recommended Common Equity Cost Rate	11.00%

Upon cross-examination, witness Ahern testified that she utilized similar methods for Aqua NC in this proceeding as in the testimony she recently presented for Utility Center, Inc. d/b/a Aqua Indiana, Inc., (Cause No. 43874), in which she recommended a return of common equity of 11.25%. She testified that, in that case, the Indiana Utility Regulatory Commission approved a 9.60% return on common equity.

Public Staff witness Hinton testified that he employed the constant growth DCF model to determine the cost of equity. He employed the CAPM and the Comparable Earnings methods as checks on his DCF results. He analyzed Aqua American by itself, a proxy group of eight other water companies, and a group of gas and electric utilities with comparable risks.

Witness Hinton's comparable group consisted of eight utility water companies covered in the Standard and Expanded Editions of Value Line and listed on witness Hinton's Exhibit JRH-4. These eight companies were also included in Company witness Ahern's nine-company proxy group, which included Aqua America as well. Witness Hinton did not include Aqua America in his group. Based on various Value Line risk measures that are widely available to investors, as well as several S&P financial risk measures and operating ratios comparisons, witness Hinton determined that the group of eight water utilities was comparable in both business risk and financial risk to Aqua America, and Aqua NC's water and wastewater operations.

Based on his review of various measures of risk for the common stock and the debt of Aqua America, witness Hinton examined comparable-risk utilities outside of the water industry that obtained at least 50% of their revenue from regulated operations. Based on Value Line's Beta coefficient, Safety Rank, Price Stability Rank, the Earning Predictability Ranking, and S&P's Bond Rating, witness Hinton developed his comparable group of electric and gas local distribution companies.

To estimate investor expectations for Aqua America and the comparable group of companies, witness Hinton examined the historical growth rates of earnings, dividends, and book value compiled by Value Line. Witness Hinton also examined forecast growth rates of earnings, dividends, and book value by Value Line and forecast earnings of various security analysts compiled by Yahoo Finance.

Based on his analysis, witness Hinton determined that the investor-required rate of return to the company-specific Aqua America DCF result was within the range of 9.40% to 10.20%, which was consistent with a dividend yield of 2.80% and an expected growth rate of 6.60% to 7.40%. Witness Hinton testified that the results of the DCF model on a comparable group of eight water companies yielded a cost of common equity ranging from 8.20% to 9.60%, and the DCF results for his group of comparable electric and gas utilities yielded a cost of common equity ranging from 8.60% to 10.00%. Witness Hinton further testified that he placed primary weight on his company-specific results for Aqua America and concluded that his point estimate for the cost of common equity was 9.80%.

Witness Hinton testified that he employed the CAPM and the Comparable Earnings methods to provide a check on his results from the DCF method. Witness Hinton used the traditional form of the CAPM method that relied on current 20-year treasury yields to estimate the risk-free rate. He incorporated the historical Arithmetic Mean Returns of 11.90% and the historical Geometric Mean Returns of 9.90%, as reported by Ibbotson Associates, Inc., to estimate the expected return on the market that ranged from 5.58% to 7.58%. With the use of the Value Line Beta coefficient, his estimate of the risk-free rate, and the market premium, witness Hinton testified that the method indicated that the cost of equity was within the range of 8.50% to 10.00%. (The Commission notes that, as shown on Hinton witness Exhibit JRH-7, Page 2, Hinton's low value, 8.44%, is actually outside of an 8.50% to 10.00% range). The CAPM results are shown in witness Hinton Exhibit JRH-7, Pages 1 and 2.

Witness Hinton also performed a Comparable Earnings analysis on the earned returns on common equity for Aqua America and his comparable group of eight water utilities. In conducting his analysis, witness Hinton computed a three-year and a five-year average return. From this method, he testified that he concluded that the cost of equity for Aqua America was within the range of 8.50% to 10.00%. Furthermore, he noted that both the three-year average and the five-year average earned returns on common equity for Aqua America was 9.80%. The results of his Comparable Earning analysis were provided in Hinton Exhibit JRH-9.

Witness Hinton testified that his recommended equity return, in combination with his recommended capital structure, would provide the Company with the opportunity for a pre-tax interest coverage of 3.6 times. Witness Hinton testified that this level of coverage should allow Aqua to qualify for a single "A" bond rating.

The determination of the appropriate fair rate of return for Aqua NC is of great importance and must be made with great care because whatever return is allowed will have an immediate impact on Aqua NC, its stockholders, and its customers. In the final analysis, the determination of a fair rate of return must be made by this Commission, using impartial judgment and guided by the testimony of expert witnesses and other evidence of record. Whatever return is allowed must balance the interest of the ratepayers and investors and meet the test set forth in G.S. 62-133(b)(4):

> . . . (to) 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 which are reasonable and which are fair to its customers and to its existing investors.

The return allowed must not burden ratepayers any more than is necessary for the utility to continue to provide adequate service. The North Carolina Supreme Court has stated that the history of G.S. 62-133(b):

> . . . supports the inference that the 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 . . . .

State ex rel. Utilities Commission v. Duke Power Co., 285 N.C. 377, 206 S.E. 2d 269 (1974).

The nature of the evidence in a case such as this makes it extremely difficult to balance all of the opposing interests, since much, if not all, of the evidence is based on individual witnesses' perceptions and interpretations of trends and data from the capital market. The Commission must use impartial judgment to ensure that all parties involved are treated fairly and equitably.

The rates of return on common equity recommended by the parties in this case range from a low of 9.80% recommended by the Public Staff to a high of 11.00% recommended by the Company. It is generally agreed that the determination of a fair and reasonable rate of return is a matter of informed judgment and that the various methodologies used to make such a determination serve as no more than guides or channels to aid in exercising such judgment. The North Carolina Supreme Court said:

> The apparent precision with which experts, both for the utility and the protestants, compute a fair return is somewhat illusory. The habitual bickering and theorizing of such witnesses over the relative merits of methods of computing cost of equity

capital, such as the earnings-to-price ratio or the discounted cash flow, lends a false appearance of certainty to the ultimate decision which is for the Commission.

State ex rel. Utilities Commission v. General Telephone Company of the Southeast, 281 N.C. 318, 370-71, 189 S.E. 2d (705) (1972).

Based upon the foregoing and all other evidence of record, the Commission finds and concludes that the reasonable rate of return for Aqua NC to be allowed on its common equity capital is 10.20%. Combining this with the appropriate capital structure, and cost of debt and preferred stock heretofore determined yields an overall rate of return of 7.86% to be applied to the Company's rate base. Such rates of return will enable Aqua NC to produce a fair rate of return for its stockholders, to maintain facilities and services in accordance with the reasonable requirements of its customers, and to compete in the capital market for funds on terms which are reasonable and fair to the Company's customers and existing investors.

The authorized rate of return on common equity of 10.20% allowed in this case is consistent with competent, material, and substantial evidence offered in this proceeding. While higher than the 9.80% recommended by witness Hinton, the 10.2% is at the high end of Mr. Hinton's range from his company-specific Aqua America DCF analysis. While lower than the 11.00% recommendation of witness Ahern, the 10.2% is in line with her analysis of the proxy group of nine water companies. Aqua NC's reliance on the Acquisition Incentive Account (AIA)[1] should act to lower Aqua NC's business and regulatory risk from the risk that would exist absent the account. In addition, the Commission approved a $300,000 incentive in Docket No. W-218, Sub 143, in conjunction with the acquisition of Hydraulics, Ltd., that is separate from the AIA. Further, to the extent Aqua NC is able to finance acquisitions with loans at below market interest rates through the NC State Revolving Fund to acquire upgrades to systems, Aqua NC's business and regulatory risk should be reduced.

The Commission believes that the rate of return on common equity of 11.00% requested by the Company is excessive, while the rate of return on common equity of 9.80% recommended by the Public Staff is too conservative. Therefore, it is the judgment of the Commission, after weighing the conflicting testimony offered by expert witnesses, that the reasonable and appropriate rate of return on common equity for Aqua NC is 10.20%. It is well settled law in this State that it is for the administrative body, in an adjudicatory proceeding, to determine the weight and sufficiency of the evidence and the credibility of the witnesses, to draw inferences from the facts, and to appraise conflicting evidence. Commissioner of Insurance v. Rate Bureau, 300 N.C. 381, 269 S.E. 2d 547 (1980). State ex rel. Utilities Commission v. Duke Power Company, 305 N.C. 1, 287 S.E. 2d 786 (1982). The Commission has followed these principles in good faith in exercising its expert judgment in determining the fair and reasonable rate of return in this proceeding. The determination of the appropriate rate of return is not a mechanical process and

[1] In Docket No. W-274, Sub 465, the Commission approved an AIA for Heater equal to two-thirds (approximately $12 million) of the acquisition premium related to Aqua America's acquisition of Heater's stock. This AIA may be converted to rate base in connection with the acquisition and upgrade of nonviable systems in North Carolina in accordance with the terms of the Stipulation between Aqua America and the Public Staff, as adopted by Commission Order dated May 26, 2004.

can only be made after a study of the evidence based upon careful consideration of a number of different methodologies weighted and tempered by the Commission's impartial judgment.

The Commission cannot guarantee that Aqua NC will in fact achieve the levels of return on rate base and common equity herein found to be just and reasonable. Indeed, the Commission would not guarantee the authorized rates of return even if it could. Such a guarantee would remove necessary incentives for the Company to achieve the utmost in operational and managerial efficiency. The Commission concludes that the rates of return approved in this docket will afford the Company a reasonable opportunity to earn a reasonable return for its stockholders while providing adequate economical service to its ratepayers.

The Commission concludes that the appropriate overall rate of return is 7.86% which is based on a capital structure of 50.42% long-term debt with an embedded cost of debt of 5.56%, and 49.58% common equity with a return on common equity of 10.20%.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 66 THROUGH 68

The Commission has previously discussed its findings of fact and conclusions regarding the issues in this proceeding including the matter of the overall fair rate of return which the Company should be allowed an opportunity to earn on its original cost rate base.

The following schedules summarize the gross revenue and rate of return that the Company should have a reasonable opportunity to achieve based upon the increases in revenues approved in this Order for each rate entity. These schedules, illustrating the Company's gross revenue requirements, incorporate the adjustments found appropriate by the Commission in this Order.

SCHEDULE I
Aqua North Carolina, Inc.
Docket No. W-218, Sub 319
Net Operating Income for a Return
For the Twelve Months Ended July 31, 2010
Combined Operations

	Present Rates	Increase Approved	After Approved Increase
Operating Revenues:			
Service revenues	$43,234,707	$ 2,282,232	$45,516,939
Late payment fees	114,453	5,811	120,264
Miscellaneous revenues	1,322,706	-	1,322,706
Uncollectibles	(325,563)	(15,273)	(340,836)
Total operating revenues	44,346,303	2,272,770	46,619,073
Operating Revenue Deductions:			
Salaries and wages	7,863,995	-	7,863,995
Employee pensions and benefits	1,899,211	-	1,899,211
Purchased water/sewer treatment	1,369,036	-	1,369,036
Sludge removal	427,572	-	427,572
Purchased power	2,888,587	-	2,888,587
Fuel for power production	10,067	-	10,067

Chemicals	1,126,469	-	1,126,469
Materials and supplies	269,109	-	269,109
Testing fees	980,686	-	980,686
Transportation	1,460,236	-	1,460,236
Contractual services	3,048,548	-	3,048,548
Rent	575,663	-	575,663
Insurance	598,617	-	598,617
Regulatory commission expense	192,122	-	192,122
Miscellaneous expense	1,422,005	-	1,422,005
Interest on customer deposits	23,979	-	23,979
Annualization & consumption adjustments	80,293	-	80,293
System transfer/abandonment adjustments	(424,280)	-	(424,280)
Total O&M and G&A expense	23,811,915	-	23,811,915
Depreciation and amortization expense	6,530,688	-	6,530,688
Property taxes	488,835	-	488,835
Payroll taxes	579,361	-	579,361
Other taxes	219	-	219
Section 338(h) adjustment	(171,915)	-	(171,915)
Regulatory fee	53,216	2,726	55,942
Gross receipts tax	1,951,621	97,808	2,049,429
State income tax	535,130	149,885	685,015
Federal income tax	2,497,298	707,824	3,205,122
Total operating revenue deductions	36,276,368	958,243	37,234,611
Net operating income for return	$ 8,069,935	$ 1,314,527	$ 9,384,462

SCHEDULE II
Aqua North Carolina, Inc.
Docket No. W-218, Sub 319
Original Cost Rate Base
For the Test Year Ended July 31, 2010
Combined Operations

	Amount
Plant in service	$346,636,347
Accumulated depreciation	(108,491,025)
Contributions in aid of construction	(154,388,727)
Accumulated amortization of CIAC	42,384,789
Acquisition adjustments	1,863,960
Accumulated amortization of acquisition adjustments	1,917,198
Advances for construction	(4,418,554)
Net plant in service	125,503,988
Customer deposits	(384,873)
Unclaimed refunds and cost-free capital	(193,293)
Accumulated deferred income taxes	(7,610,422)
Materials and supplies inventory	1,088,109
Excess capacity adjustment	(1,443,840)
Working capital allowance	2,427,757
Original cost rate base	$119,387,426
Rates of return:	
Present	6.76%
Approved	7.86%

SCHEDULE III
Aqua North Carolina, Inc.
Docket No. W-218, Sub 319
Statement of Capitalization and Related Costs
For the Test Year Ended July 31, 2010
Combined Operations

Item	Capitalization Ratio	Original Cost Rate Base	Embedded Cost or Return	Net Operating Income
		Present Rates – Original Cost Rate Base		
Long-Term Debt	50.42%	$60,195,140	5.56%	$3,346,850
Common Equity	49.58%	59,192,286	7.98%	4,723,085
Total	100.00%	$119,387,426		$8,069,935
		Approved Rates – Original Cost Rate Base		
Long-Term Debt	50.42%	$60,195,140	5.56%	$3,346,850
Common Equity	49.58%	59,192,286	10.20%	6,037,612
Total	100.00%	$119,387,426		$9,384,462

SCHEDULE I-A
Aqua North Carolina, Inc.
Docket No. W-218, Sub 319
Net Operating Income for a Return
For the Twelve Months Ended July 31, 2010
Aqua Water Operations

	Present Rates	Increase Approved	After Approved Increase
Operating Revenues:			
Service revenues	$ 27,268,704	$ 1,761,158	$ 29,029,862
Late payment fees	70,899	4,579	75,478
Miscellaneous revenues	761,018	-	761,018
Uncollectibles	(185,909)	(12,007)	(197,916)
Total operating revenues	27,914,712	1,753,730	29,668,442
Operating Revenue Deductions:			
Salaries and wages	5,210,655	-	5,210,655
Employee pensions and benefits	1,259,888	-	1,259,888
Purchased water	1,012,485	-	1,012,485
Purchased power	1,707,869	-	1,707,869
Fuel for power production	-	-	-
Chemicals	484,675	-	484,675
Materials and supplies	168,309	-	168,309
Testing fees	649,080	-	649,080
Transportation	976,064	-	976,064
Contractual services	1,547,535	-	1,547,535
Rent	219,873	-	219,873
Insurance	383,649	-	383,649
Regulatory commission expense	111,570	-	111,570
Miscellaneous expense	866,328	-	866,328
Interest on customer deposits	17,705	-	17,705
Annualization & consumption adjustments	34,337	-	34,337
System transfer/abandonment adjustments	(91,623)	-	(91,623)

Total O&M and G&A expense	14,558,399	-	14,558,399
Depreciation and amortization expense	4,450,104	-	4,450,104
Property taxes	357,789	-	357,789
Payroll taxes	384,585	-	384,585
Other taxes	140	-	140
Section 338(h) adjustment	(107,838)	-	(107,838)
Regulatory fee	33,498	2,104	35,602
Gross receipts tax	1,094,566	70,149	1,164,715
State income tax	339,298	116,022	455,320
Federal income tax	1,579,798	547,910	2,127,708
Total operating revenue deductions	22,690,339	736,185	23,426,524
Net operating income for return	$ 5,224,373	$ 1,017,545	$ 6,241,918

SCHEDULE II-A
Aqua North Carolina, Inc.
Docket No. W-218, Sub 319
Original Cost Rate Base
For the Test Year Ended July 31, 2010
Aqua Water Operations

	Amount
Plant in service	$200,960,989
Accumulated depreciation	(68,337,739)
Contributions in aid of construction	(76,322,246)
Accumulated amortization of CIAC	22,326,671
Acquisition adjustments	5,944,052
Accumulated amortization of acquisition adjustments	(301,081)
Advances for construction	(2,146,714)
Net plant in service	82,123,932
Customer deposits	(284,747)
Unclaimed refunds and cost-free capital	(46,582)
Accumulated deferred income taxes	(4,783,739)
Materials and supplies inventory	868,184
Excess capacity adjustment	-
Working capital allowance	1,531,507
Original cost rate base	$ 79,408,555
Rates of return:	
Present	6.58%
Approved	7.86%

WATER AND SEWER – RATE INCREASE

SCHEDULE III-A
Aqua North Carolina, Inc.
Docket No. W-218, Sub 319
Statement of Capitalization and Related Costs
For the Test Year Ended July 31, 2010
Aqua Water Operations

Item	Capitalization Ratio	Original Cost Rate Base	Embedded Cost or Return	Net Operating Income
		Present Rates – Original Cost Rate Base		
Long-Term Debt	50.42%	$40,037,793	5.56%	$2,226,101
Common Equity	49.58%	39,370,762	7.62%	2,998,272
Total	100.00%	$79,408,555		$5,224,373
		Approved Rates – Original Cost Rate Base		
Long-Term Debt	50.42%	$40,037,793	5.56%	$2,226,101
Common Equity	49.58%	39,370,762	10.20%	4,015,817
Total	100.00%	$79,408,555		$6,241,918

SCHEDULE I-B
Aqua North Carolina, Inc.
Docket No. W-218, Sub 319
Net Operating Income for a Return
For the Twelve Months Ended July 31, 2010
Aqua Sewer Operations

	Present Rates	Increase Approved	After Approved Increase
Operating Revenues:			
Service revenues	$ 9,582,238	$ 280,915	$ 9,863,153
Late payment fees	20,123	590	20,713
Miscellaneous revenues	134,784	-	134,784
Uncollectibles	(62,415)	(1,830)	(64,245)
Total operating revenues	9,674,730	279,675	9,954,405
Operating Revenue Deductions:			
Salaries and wages	1,549,427	-	1,549,427
Employee pensions and benefits	372,838	-	372,838
Purchased sewer treatment	164,683	-	164,683
Sludge removal	386,714	-	386,714
Purchased power	815,053	-	815,053
Fuel for power production	6,339	-	6,339
Chemicals	467,838	-	467,838
Materials and supplies	74,518	-	74,518
Testing fees	243,721	-	243,721
Transportation	307,413	-	307,413
Contractual services	980,495	-	980,495
Rent	58,114	-	58,114
Insurance	100,535	-	100,535
Regulatory commission expense	25,031	-	25,031
Miscellaneous expense	346,665	-	346,665
Interest on customer deposits	1,889	-	1,889
Annualization & consumption adjustments	34,453	-	34,453

System transfer/abandonment adjustments	(326,714)	-	(326,714)
Total O&M and G&A expense	5,609,012	-	5,609,012
Depreciation and amortization expense	1,061,361	-	1,061,361
Property taxes	11,045	-	11,045
Payroll taxes	115,285	-	115,285
Other taxes	28	-	28
Section 338(h) adjustment	(35,807)	-	(35,807)
Regulatory fee	11,610	335	11,945
Gross receipts tax	579,667	16,780	596,447
State income tax	115,449	18,117	133,566
Federal income tax	545,205	85,555	630,760
Total operating revenue deductions	8,012,855	120,787	8,133,642
Net operating income for return	$ 1,661,875	$ 158,888	$ 1,820,763

SCHEDULE II-B
Aqua North Carolina, Inc.
Docket No. W-218, Sub 319
Original Cost Rate Base
For the Test Year Ended July 31, 2010
Aqua Sewer Operations

	Amount
Plant in service	$103,431,945
Accumulated depreciation	(26,277,579)
Contributions in aid of construction	(61,290,977)
Accumulated amortization of CIAC	14,047,278
Acquisition adjustments	(4,048,666)
Accumulated amortization of acquisition adjustments	2,187,084
Advances for construction	(2,761,590)
Net plant in service	25,287,495
Customer deposits	(29,042)
Unclaimed refunds and cost-free capital	(6,342)
Accumulated deferred income taxes	(1,400,233)
Materials and supplies inventory	164,390
Excess capacity adjustment	(1,443,840)
Working capital allowance	590,969
Original cost rate base	$ 23,163,397
Rates of return:	
Present	7.17%
Approved	7.86%

SCHEDULE III-B
Aqua North Carolina, Inc.
Docket No. W-218, Sub 319
Statement of Capitalization and Related Costs
For the Test Year Ended July 31, 2010
Aqua Sewer Operations

Item	Capitalization Ratio	Original Cost Rate Base	Embedded Cost or Return	Net Operating Income
		Present Rates – Original Cost Rate Base		
Long-Term Debt	50.42%	$11,678,985	5.56%	$649,352
Common Equity	49.58%	11,484,412	8.82%	1,012,523
Total	100.00%	$23,163,397		$1,661,875
		Approved Rates – Original Cost Rate Base		
Long-Term Debt	50.42%	$11,678,985	5.56%	$649,352
Common Equity	49.58%	11,484,412	10.20%	1,171,411
Total	100.00%	$23,163,397		$1,820,763

SCHEDULE I-C
Aqua North Carolina, Inc.
Docket No. W-218, Sub 319
Net Operating Income for a Return
For the Twelve Months Ended July 31, 2010
Fairways Water Operations

	Present Rates	Increase Approved	After Approved Increase
Operating Revenues:			
Service revenues	$ 752,240	$ 171,809	$ 924,049
Late payment fees	2,106	481	2,587
Miscellaneous revenues	79,990	-	79,990
Uncollectibles	(3,923)	(896)	(4,819)
Total operating revenues	830,413	171,394	1,001,807
Operating Revenue Deductions:			
Salaries and wages	182,895	-	182,895
Employee pensions and benefits	43,507	-	43,507
Purchased water	-	-	-
Purchased power	58,483	-	58,483
Fuel for power production	-	-	-
Chemicals	18,457	-	18,457
Materials and supplies	1,465	-	1,465
Testing fees	18,147	-	18,147
Transportation	28,559	-	28,559
Contractual services	92,123	-	92,123
Rent	10,715	-	10,715
Insurance	19,583	-	19,583
Regulatory commission expense	6,904	-	6,904
Miscellaneous expense	37,209	-	37,209
Interest on customer deposits	408	-	408
Annualization & consumption adjustments	2,535	-	2,535

System transfer/abandonment adjustments	(1,021)	-	(1,021)
Total O&M and G&A expense	519,969	-	519,969
Depreciation and amortization expense	139,443	-	139,443
Property taxes	43,716	-	43,716
Payroll taxes	13,139	-	13,139
Other taxes	8	-	8
Section 338(h) adjustment	-	-	-
Regulatory fee	996	206	1,202
Gross receipts tax	30,823	6,856	37,679
State income tax	1,364	11,339	12,703
Federal income tax	5,013	53,547	58,560
Total operating revenue deductions	754,471	71,948	826,419
Net operating income for return	$ 75,942	$ 99,446	$ 175,388

SCHEDULE II-C
Aqua North Carolina, Inc.
Docket No. W-218, Sub 319
Original Cost Rate Base
For the Test Year Ended July 31, 2010
Fairways Water Operations

	Amount
Plant in service	$8,070,647
Accumulated depreciation	(1,713,827)
Contributions in aid of construction	(5,063,692)
Accumulated amortization of CIAC	995,244
Acquisition adjustments	-
Accumulated amortization of acquisition adjustments	-
Advances for construction	245,250
Net plant in service	2,533,622
Customer deposits	(7,090)
Unclaimed refunds and cost-free capital	(7,377)
Accumulated deferred income taxes	(337,090)
Materials and supplies inventory	-
Excess capacity adjustment	-
Working capital allowance	49,186
Original cost rate base	$2,231,251
Rates of return:	
Present	3.40%
Approved	7.86%

SCHEDULE III-C
Aqua North Carolina, Inc.
Docket No. W-218, Sub 319
Statement of Capitalization and Related Costs
For the Test Year Ended July 31, 2010
Fairways Water Operations

Item	Capitalization Ratio	Original Cost Rate Base	Embedded Cost or Return	Net Operating Income
	Present Rates – Original Cost Rate Base			
Long-Term Debt	50.42%	$1,124,997	5.56%	$62,550
Common Equity	49.58%	1,106,254	1.21%	13,392
Total	100.00%	$2,231,251		$75,942
	Approved Rates – Original Cost Rate Base			
Long-Term Debt	50.42%	$1,124,997	5.56%	$62,550
Common Equity	49.58%	1,106,254	10.20%	112,838
Total	100.00%	$2,231,251		$175,388

SCHEDULE I-D
Aqua North Carolina, Inc.
Docket No. W-218, Sub 319
Net Operating Income for a Return
For the Twelve Months Ended July 31, 2010
Fairways Sewer Operations

	Present Rates	Increase Approved	After Approved Increase
Operating Revenues:			
Service revenues	$ 980,666	$ 65,547	$ 1,046,213
Late payment fees	2,256	150	2,406
Miscellaneous revenues	1,388	-	1,388
Uncollectibles	(7,470)	(500)	(7,970)
Total operating revenues	976,840	65,197	1,042,037
Operating Revenue Deductions:			
Salaries and wages	166,769	-	166,769
Employee pensions and benefits	39,625	-	39,625
Purchased sewer treatment	506	-	506
Sludge removal	40,858	-	40,858
Purchased power	69,865	-	69,865
Fuel for power production	-	-	-
Chemicals	22,221	-	22,221
Materials and supplies	2,052	-	2,052
Testing fees	20,255	-	20,255
Transportation	27,781	-	27,781
Contractual services	98,723	-	98,723
Rent	7,460	-	7,460
Insurance	15,170	-	15,170
Regulatory commission expense	4,838	-	4,838
Miscellaneous expense	30,894	-	30,894
Interest on customer deposits	73	-	73
Annualization & consumption adjustments	625	-	625

System transfer/abandonment adjustments	(726)	-	(726)
Total O&M and G&A expense	546,989	-	546,989
Depreciation and amortization expense	112,075	-	112,075
Property taxes	789	-	789
Payroll taxes	12,138	-	12,138
Other taxes	5	-	5
Section 338(h) adjustment	-	-	-
Regulatory fee	1,172	78	1,250
Gross receipts tax	58,560	3,912	62,472
State income tax	11,604	4,223	15,827
Federal income tax	54,797	19,945	74,742
Total operating revenue deductions	798,129	28,158	826,287
Net operating income for return	$ 178,711	$ 37,039	$ 215,750

SCHEDULE II-D
Aqua North Carolina, Inc.
Docket No. W-218, Sub 319
Original Cost Rate Base
For the Test Year Ended July 31, 2010
Fairways Sewer Operations

	Amount
Plant in service	$7,271,902
Accumulated depreciation	(1,162,720)
Contributions in aid of construction	(4,012,609)
Accumulated amortization of CIAC	693,184
Acquisition adjustments	-
Accumulated amortization of acquisition adjustments	-
Advances for construction	244,500
Net plant in service	3,034,257
Customer deposits	(918)
Unclaimed refunds and cost-free capital	(217)
Accumulated deferred income taxes	(352,999)
Materials and supplies inventory	-
Excess capacity adjustment	-
Working capital allowance	64,626
Original cost rate base	2,744,749
Rates of return:	
Present	6.51%
Approved	7.86%

SCHEDULE III-D
Aqua North Carolina, Inc.
Docket No. W-218, Sub 319
Statement of Capitalization and Related Costs
For the Test Year Ended July 31, 2010
Fairways Sewer Operations

Item	Capitalization Ratio	Original Cost Rate Base	Embedded Cost or Return	Net Operating Income
	Present Rates – Original Cost Rate Base			
Long-Term Debt	50.42%	$1,383,902	5.56%	$76,945
Common Equity	49.58%	1,360,847	7.48%	101,766
Total	100.00%	$2,744,749		$178,711
	Approved Rates – Original Cost Rate Base			
Long-Term Debt	50.42%	$1,383,902	5.56%	$76,945
Common Equity	49.58%	1,360,847	10.20%	138,805
Total	100.00%	$2,744,749		$215,750

SCHEDULE I-E
Aqua North Carolina, Inc.
Docket No. W-218, Sub 319
Net Operating Income for a Return
For the Twelve Months Ended July 31, 2010
Brookwood Water Operations

	Present Rates	Increase Approved	After Approved Increase
Operating Revenues:			
Service revenues	$ 4,650,859	$ 2,803	$ 4,653,662
Late payment fees	19,069	11	19,080
Miscellaneous revenues	345,526	-	345,526
Uncollectibles	(65,846)	(40)	(65,886)
Total operating revenues	4,949,608	2,774	4,952,382
Operating Revenue Deductions:			
Salaries and wages	754,249	-	754,249
Employee pensions and benefits	183,353	-	183,353
Purchased water	191,362	-	191,362
Purchased power	237,317	-	237,317
Fuel for power production	3,728	-	3,728
Chemicals	133,278	-	133,278
Materials and supplies	22,765	-	22,765
Testing fees	49,483	-	49,483
Transportation	120,419	-	120,419
Contractual services	329,672	-	329,672
Rent	279,501	-	279,501
Insurance	79,680	-	79,680
Regulatory commission expense	43,779	-	43,779
Miscellaneous expense	140,909	-	140,909
Interest on customer deposits	3,904	-	3,904
Annualization & consumption adjustments	8,343	-	8,343
System transfer/abandonment adjustments	(4,196)	-	(4,196)

Total O&M and G&A expense	2,577,546	-	2,577,546
Depreciation and amortization expense	767,705	-	767,705
Property taxes	75,496	-	75,496
Payroll taxes	54,214	-	54,214
Other taxes	38	-	38
Section 338(h) adjustment	(28,270)	-	(28,270)
Regulatory fee	5,940	3	5,943
Gross receipts tax	188,005	111	188,116
State income tax	67,415	184	67,599
Federal income tax	312,485	867	313,352
Total operating revenue deductions	4,020,574	1,165	4,021,739
Net operating income for return	$ 929,034	$ 1,609	$ 930,643

SCHEDULE II-E
Aqua North Carolina, Inc.
Docket No. W-218, Sub 319
Original Cost Rate Base
For the Test Year Ended July 31, 2010
Brookwood Water Operations

	Amount
Plant in service	$26,900,864
Accumulated depreciation	(10,999,160)
Contributions in aid of construction	(7,699,203)
Accumulated amortization of CIAC	4,322,412
Acquisition adjustments	(31,426)
Accumulated amortization of acquisition adjustments	31,195
Advances for construction	-
Net plant in service	12,524,682
Customer deposits	(63,076)
Unclaimed refunds and cost-free capital	(132,775)
Accumulated deferred income taxes	(736,361)
Materials and supplies inventory	55,535
Excess capacity adjustment	-
Working capital allowance	191,469
Original cost rate base	$11,839,474
Rates of return:	
Present	7.84%
Approved	7.86%

SCHEDULE III-E
Aqua North Carolina, Inc.
Docket No. W-218, Sub 319
Statement of Capitalization and Related Costs
For the Test Year Ended July 31, 2010
Brookwood Water Operations

Item	Capitalization Ratio	Original Cost Rate Base	Embedded Cost or Return	Net Operating Income
		Present Rates – Original Cost Rate Base		
Long-Term Debt	50.42%	$5,969,463	5.56%	$331,902
Common Equity	49.58%	5,870,011	10.17%	597,132
Total	100.00%	$11,839,474		$929,034
		Approved Rates – Original Cost Rate Base		
Long-Term Debt	50.42%	$5,969,463	5.56%	$331,902
Common Equity	49.58%	5,870,011	10.20%	598,741
Total	100.00%	$11,839,474		$930,643

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 69 THROUGH 75

The evidence supporting these findings of fact is contained in the testimony of Public Staff witness Tweed and Aqua NC witness Roberts.

Aqua NC is opposed to the Public Staff's proposal to change from flat rate sewer charges to metered rates. A high percentage of the costs of wastewater treatment operations are fixed, and that cost fluctuates little based on the volume of wastewater actually treated. Public Staff witness Tweed testified that a high percentage of the costs of wastewater treatment operations are fixed and the cost that fluctuates is very low. He also acknowledged that the Public Staff has historically supported flat rate wastewater rates based upon its conclusion that a large percentage of the cost of operating a wastewater is fixed with the amount of flow coming through the system having no great impact on the cost of operations.

Aqua NC witness Roberts agrees with the fact that wastewater plants are very high fixed cost operations. The treatment of wastewater is unique in that Aqua NC incurs almost the same operating, maintenance, and treatment expenses regardless of the volume of wastewater that is treated at a wastewater plant.

Witness Roberts testified that the volumetric sewer service rate structure proposed by the Public Staff would increase volatility in revenues which will invariably make it more difficult to collect Aqua NC's full revenue requirement. In essence, a mismatch would occur because, as stated above, most of the cost of providing sewer service is fixed and the variable cost component of that service is quite small. Witness Roberts testified that if the Commission accepted the Public Staff's new policy on wastewater rate design, there will be a significantly increased business risk going forward for the Company. Witness Tweed acknowledged that the proposed volumetric sewer rate structure would increase Aqua NC's business risk and the difficulty of achieving Aqua NC's authorized return on equity.

Witness Roberts testified that in addition to the increased risk to Aqua NC posed by the Public Staff's proposed sewer rate design, if the rates are correctly designed, there will simply be new sets of winners and losers in the ranks of Aqua NC's ratepayers. Witness Roberts testified that this revised rate structure would simply shift costs from certain customers to other customers. Witness Roberts challenged the Public Staff's suggestion that the reason for its dramatic shift from its former preference for flat rated sewer service is because the level of wastewater rates has become higher and the flat monthly rate has become burdensome for customers. Witness Roberts asserted that the notion that a change in rate design from flat to metered wastewater rates will allow ratepayers to "save money" is misleading. Along this line, witness Roberts maintained that assuming the revenue requirement remains fixed, proper rate design would dictate that if there are some customers that pay less, then there must be other others that pay more.

Witness Roberts identified a number of logistical, legal, and ratemaking issues raised by the Public Staff's proposal. First, he noted that Aqua NC serves approximately 5,250 customers that receive water either from their own private well, or from a third-party water provider, such as a municipality. As a result, witness Roberts noted that Aqua NC has no access to any data as to how much water those customers on private wells use, which would preclude metered wastewater billing as to them.

Second, Aqua NC serves a number of communities where residential customers have separate meters for irrigation. The Public Staff's inclusion of data from irrigation meters in the calculation of average gallons metered in the context of sewer service unfairly inflates the gallons metered and may have influenced the rate designer to propose a higher cap. In any case, those customers with separate irrigation meters should be required to pay a sewer bill for all water that is measured through the primary or domestic (non-irrigation) meter. Witness Roberts testified that this will become an even more significant issue as customers either request or are required by state or local requirements to have separate meters for irrigation.

Third, witness Roberts noted that the Public Staff has not even considered the scenario in which a voluntary arrangement cannot be made to get water usage data from a third-party water provider. Nor has the Public Staff made any provision for ratemaking purposes for the associated additional costs, which are scrutinized elsewhere.

Fourth, witness Roberts maintained that there would certainly be personal information and legal issues associated with the implementation of the proposed conversion. A private company such as Aqua NC cannot enter private property to install a meter on a third-party's service line or well, particularly when that party is not regulated by the North Carolina Utilities Commission.

The Public Staff noted that in Docket No. W-218 Sub 274, after considerable discussion including testimony from Aqua NC customers about metered sewer rates, the Commission concluded that it "is concerned about the issues raised by flat-rate sewer versus volumetric sewer and is mindful of a high level of customer focus on that issue." In its Order issued in that docket on April 8, 2009, the Commission required in Decretal Paragraph No. 21 that Aqua NC "investigate and report to the Commission and the Public Staff a volumetric sewer rate that would provide the sewer utility service revenues approved herein."

In the current rate case, there was additional customer concern expressed primarily reflecting the unfairness of the flat monthly rate to the low-volume users. Customers expressing concern from the Winston-Salem area included Mr. James Boturla who testified that "I have two [sic] persons in my house, two adults, one child. Somebody across the street has six people. Why do I pay the same amount? It doesn't seem fair." Ms. Cheryl Branch testified that "I live there all alone and I work nine hours a day, so I'm never there." She further testified that she would like to see a metered rate. Ms. Gina Dinkins testified "So to me, a fair way to bill clients for wastewater would be to use the volume of water used." Other customers provided similar support for metered sewer rates. One customer, Mr. Ryan Swanson, testified generally that he would not prefer a metered sewer rate since he would have to pay for irrigation and other water that did not go back into the sewer system.

Public Staff witness Tweed recommended a metered sewer rate based upon water usage with a cap of 7,000 gallons of monthly usage above which the residential customers would not have to pay for sewer service. He also recommended the same monthly base charges for zero usage as currently approved by the Commission for small commercial customers in the Aqua Sewer ($23.13) and Fairways Sewer ($11.44) service areas.

Further, witness Tweed testified that approximately 9,250 of the 14,500 residential sewer customers were provided water service by Aqua NC and therefore could be billed at a metered rate. Most of the remaining 5,250 customers would require some follow-up by Aqua NC to determine if the municipal and county water providers could provide meter readings or perform metered billing services for Aqua NC and at what cost, if any. In response to Public Staff Engineering Data Request No. 1 dated January 26, 2011, Aqua NC provided a summary of its initial contacts with each of the municipal and county water providers and none apparently ruled out the possibility of Aqua NC receiving billing services, meter readings, or being allowed to read the municipal meters to accomplish the goal of metered sewer rates. As of the June 2011 evidentiary hearing, no follow-up had been performed by Aqua NC to attempt to firm up any commitments from the suppliers and provide any firm cost data to the Public Staff regarding whichever option was preferred by Aqua NC.

Witness Tweed recommended that Aqua NC be required to follow-up and exhaust all efforts to obtain the data or services from the water providers and file monthly progress reports for a maximum of six months by which time the issues for all service areas should have been resolved. He further recommended that as soon as an agreement was implemented with a provider, that Aqua NC should begin charging the Commission-approved metered rate and so notify the Commission in its monthly report.

The Commission agrees with both witnesses and the evidence in the record that supports a finding that a high percentage of the costs of wastewater treatment operations are fixed and that cost fluctuates little based on the volume of wastewater actually treated. The Commission agrees that the Public Staff has historically supported flat monthly sewer rates based upon a conclusion that a large percentage of the cost of operating a sewer system is fixed, with the amount of flow coming into the system not having a great impact upon the cost of the operation.

Furthermore, the Commission agrees that under the Public Staff's proposed sewer rate design, if the rates are correctly designed, there will simply be new sets of winners and losers in the ranks of Aqua NC's ratepayers; that this revised rate structure would simply shift costs from certain customers to other customers; and that assuming the revenue requirement remains fixed, proper rate design would dictate that if there are some customers that pay less, then there must be other others that pay more.

Based upon the evidence, the Commission does not find any compelling reason to deviate from the sewer service flat (fixed) rate design now in place. Therefore, the Commission finds and concludes that the rate design criteria for Aqua NC's sewer service should remain as is.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 76

The Commission has previously discussed its findings of fact and conclusions regarding the issues in this proceeding and has presented schedules summarizing the gross revenue and rate of return that the Company should have a reasonable opportunity to achieve based upon the increases in revenues approved in this Order for each rate entity.

The Schedule of Rates reflecting the Commission decisions in this matter has been previously approved, on a provisional basis, by the Commission. Such just and reasonable rates became effective September 13, 2011, pursuant to the Commission's Notice of Decision and Order issued September 13, 2011, as corrected and affirmed by Errata Order issued September 23, 2011. As set forth in the Joint Stipulation, these rates will be provisional rates pending the Commission's ruling in Docket No. W-218, Sub 325 concerning (1) the treatment of any gain on sale; (2) the treatment of the loss on Windsor Oaks; (3) the revenues, expenses, and rate base associated with the Windsor Oaks system and the systems being sold to the City of Charlotte; and (4) any other rulings by the Commission in the transfer proceeding which affect the rates for Aqua NC. Following the issuance of the Commission's order in Docket No. W-218, Sub 325, Aqua NC will adjust rates accordingly and refund overcollections, if any, with interest, as determined by the Commission.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 77 THROUGH 81

The evidence supporting these findings of fact is contained in the testimony of Public Staff witness Fernald and Company witness Becker; and in the Commission's records. Witness Fernald made two accounting recommendations concerning (1) accounting for acquisition costs and (2) accounting for legal fees.

Accounting for Acquisition Costs

In prefiled testimony, Public Staff witness Fernald testified that the Company had not been properly accounting for costs related to acquisitions and pending acquisitions. Witness Fernald recommended that the Company revise its accounting practices for both North Carolina and corporate, such that costs related to acquisitions and pending acquisitions are not recorded in above-the-line expenses. Company witness Becker testified on rebuttal that appropriate measures would be installed at the state level to track payroll and legal costs and relate them to acquisitions. Witness Becker did not address the revision of accounting practices for the acquisition costs charged to North Carolina from corporate nor did he provide any information on the potential acquisitions that the Company's employees worked on during the 12 months ended March 31, 2011, for which Aqua NC is now requesting rate recovery from current customers.

Elsewhere in this Order the Commission has concluded that costs related to pending acquisitions, such as salaries and wages, should not be included in above-the-line expenses. Instead, these costs should be accumulated separately and considered as part of the costs related to the acquisition or potential acquisition. If the Company does succeed in acquiring a regulated system in North Carolina, then the costs incurred related to that acquisition, including due diligence performed by the Company, will be reviewed and, if reasonable and prudent, will be capitalized as part of the cost of acquiring the system.

Based upon the foregoing, the Company should revise its accounting practices such that costs incurred related to acquisitions and pending acquisitions, including both costs incurred at the state level and costs allocated to North Carolina from corporate or other affiliates, are not recorded in above-the-line expenses.

Accounting for Legal Fees

In prefiled testimony, witness Fernald testified that the Company had not been properly accounting for some legal fees, noting that the Company had included in regulated expenses (1) legal fees which should have been capitalized and (2) legal fees which should have been recorded below the line and not recovered from ratepayers. Witness Fernald recommended that the Company revise its accounting practices such that legal fees are properly accounted for on its books. The Company did not contest witness Fernald's adjustments to legal expense in this case. In rebuttal testimony, witness Becker testified that appropriate measures would be installed at the state level to track legal costs as well as to better control the coding for the Company's legal bills.

Based upon the foregoing, the Commission concludes that the Company should revise its accounting practices such that all legal fees, including those incurred at the state level and amounts allocated from corporate, are properly accounted for on its books.

Annual Reporting Requirement – Heater Acquisition Incentive Account

Pursuant to Decretal Paragraph No. 19 of Order issued April 8, 2009, in Docket No. W-218, Sub 274, the Commission required that Aqua NC file an annual report each June 30th to provide the Commission information regarding the status of the Heater Acquisition Incentive Account systems that Aqua NC is still working on. The Commission required that such report include all improvements made to date, an accounting of all money spent, a detailed description of the improvements still to be made, and a timeframe for the remaining improvements to be made.

Aqua NC filed reports on June 30, 2009, June 29, 2010, and June 30, 2011 in Docket No. W-218, Sub 274. The Commission observes that the information contained in such reports, although informative, does not provide all the information needed for the Commission to fully assess the status of the Heater Acquisition Incentive Account. In particular, the Commission finds that cumulative information, rather than simply an update regarding the status of systems that the Company is still working on, would provide more useful information to the Commission. Such cumulative information to be included in each annual report should be as follows:

(a) A listing of the name of each company or system acquired;
(b) The docket number in which Heater Acquisition Incentive Account treatment was approved by the Commission;
(c) The purchase price for each company or system acquired;
(d) A description of all improvements made to date by company or system;
(e) An accounting of all money spent on improvements for each company or system such that the total dollar amount expended is shown;
(f) A detailed description of the improvements still to be made for each company or system;
(g) An estimate of the total dollar amount related to improvements still to be made for each company or system;
(h) A timeframe for the remaining improvements to be made related to each company or system; and,
(i) A summary schedule which sets forth the total amount of the Heater Acquisition Incentive Account, the amount used to date, and the remaining balance in the Heater Acquisition Incentive Account.

Based upon the foregoing, the Commission concludes that the Company's current annual reporting requirement established in Docket No. W-218, Sub 274 related to the Heater Acquisition Incentive Account should be modified to include the information, as set forth hereinabove, on a cumulative basis and that such modified reporting requirement should be effective beginning with Aqua NC's next annual report, which is due to be filed on June 29, 2012.

Finally, the Commission finds and concludes that all future reports filed with the Commission related to the two annual reporting requirements established in Docket No. 218, Sub 274, by Decretal Paragraph Nos. 7 and 19 in the Commission Order dated April 8, 2009, as modified herein, regarding Aqua NC's analysis of the terms of its debt issues and the Heater Acquisition Incentive Account, respectively, should be filed in Docket No. W-218, Sub 319A, until further order of the Commission.

IT IS, THEREFORE, ORDERED as follows:

1. That the Company is hereby granted an increase in its service revenues for combined operations of $2,282,232.

2. That the Commission's Notice of Decision and Order issued September 13, 2011, and the Errata Order issued September 23, 2011, shall be, and the same are hereby, reaffirmed.

3. That the Joint Stipulation between the Company and the Public Staff regarding treatment of the Windsor Oaks system and the systems being sold to the City of Charlotte, incorporated herein by reference, is hereby approved.

4. That the Schedule of Rates reflecting the Commission decisions in this matter, as previously approved, on a provisional basis, pursuant to the Commission's Notice of Decision and Order issued September 13, 2011, as corrected and affirmed by Errata Order issued September 23, 2011, shall be, and is hereby reaffirmed. These rates, which became effective September 13, 2011, will be adjusted to reflect the Commission's rulings in Docket No. W-218, Sub 325 concerning (a) the treatment of any gain on sale; (b) the treatment of the loss on Windsor Oaks; (c) the revenues, expenses, and rate base associated with the Windsor Oaks system and the systems being sold to the City of Charlotte; and (d) any other rulings by the Commission in the transfer proceeding which affect the rates for Aqua NC. Aqua NC will adjust rates accordingly and refund overcollections, if any, with interest, as determined by the Commission.

5. That Aqua NC shall revise its accounting practices for both North Carolina and corporate, such that costs related to pending acquisitions, including both costs incurred at the state level and costs allocated to North Carolina from corporate or other affiliates, should not be recorded in above-the-line expenses. Costs related to consummated acquisitions should be capitalized as part of the cost of acquiring the system and will be subject to review for reasonableness and prudence in a future proceeding before the Commission.

6. That Aqua NC shall revise its accounting practices such that all legal fees, including those incurred at the state level and amounts allocated from corporate, are properly accounted for on its books.

7. That Aqua NC shall expand the information provided in its current annual report filed with the Commission related to the Heater Acquisition Incentive Account, which is required by final Order dated April 8, 2009 in Docket No. W-218, Sub 274, Decretal Paragraph No. 19, such that each future annual report shall provide cumulative information regarding all activity to date, as well as the status of matters currently in progress.

8. That the current annual reporting requirement related to the Heater Acquisition Incentive Account required by final Order dated April 8, 2009 in Docket No. W-218, Sub 274 shall be revised as follows:

> That Aqua NC shall file an annual report on June 30th of each year on the cumulative status of the Heater Acquisition Incentive Account. Such report shall provide a listing of the name of each company or system acquired; the corresponding docket number in which such treatment was approved by the Commission; and the purchase price for each company or system. In addition, such report shall include, for each system or company acquired, a description of all improvements made to date; an accounting of all money

spent on improvements such that the total dollar amount expended is shown; a detailed description of the improvements still to be made; an estimate of the total dollar amount related to improvements still to be made; and a timeframe for the remaining improvements to be completed. Such report shall provide a summary schedule which sets forth the total amount of the Heater Acquisition Incentive Account, the amount used to date, and the remaining balance in the Heater Acquisition Incentive Account.

9. That all future reports filed with the Commission related to the two annual reporting requirements established in Docket No. 218, Sub 274 by Decretal Paragraph Nos. 7 and 19, as modified herein, regarding Aqua NC's analysis of the terms of its debt issues and the Heater Acquisition Incentive Account, respectively, shall be filed in Docket No. W-218, Sub 319A, until further order of the Commission.

ISSUED BY ORDER OF THE COMMISSION.
This the 3rd day of November, 2011.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Chairman Edward S. Finley, Jr., concurs.

Commissioners William T. Culpepper, III, and Bryan E. Beatty did not participate in this decision.

bk110311.01

DOCKET NO. W-218, SUB 319

CHAIRMAN EDWARD S. FINLEY, JR., CONCURRING: I agree with the conclusion reached by the Commission in support of Finding of Fact 30 but for reasons different from those of the majority.

The Public Staff has advocated a $28,069 adjustment to reduce miscellaneous revenues to prevent Aqua NC from recovering payments it made to Utilities Services Communications Co, Inc. (USC) in commissions for negotiating antenna leases with parties seeking to install antennas on Aqua NC's water tanks. Aqua NC's agreement with USC was negotiated in February 2007 by an employee who no longer works for Aqua NC. The agreement with USC has an initial ten year term with extensions. Four antenna lease agreements have been negotiated by USC with annual revenues of $93,564. The 30% test year commission is $28,069.

The justification for the proposed disallowance of the $28,069 is that "in a rate case proceeding, the Company has the burden of proof to show that costs are reasonable and prudent, which includes the prudency and reasonableness of any agreements entered into by the utility with third parties." Public Staff witness Fernald testified that she requested that Aqua NC provide her with "the cost benefit analysis which it performed in reaching its decision to enter into the agreement with USC." Aqua NC was unable, in 2011, to provide a 2007 cost benefit analysis, if any, undertaken by an employee who is no longer at the Company. The Public Staff expresses its "concern" that the Company cannot document the benefit of the 2007 decision to enter into a long-term exclusive agreement with an outside party. The Public Staff asserts that the 30% commission is "high." It produces no evidence upon which it bases its conclusion. Higher than what? The Public Staff concludes its argument by asserting that "the Company has not met its burden of proof that the agreement entered into with USC was prudent, and that the commissions paid to USC pursuant to the USC Agreement are reasonable."

The Public Staff adjustment must be rejected because the Public Staff has misstated where the burden of proof lies with respect to this item and has failed to meet the burden of proof that it must meet. It has offered no affirmative evidence of unreasonableness. The Public Staff espouses an erroneous understanding of the burden of proof. In seeking to justify recovery of test year costs incurred to provide service to its ratepayers, the utility meets its initial burden of proof by verifying that it incurred the expense in question. A presumption exists that management would not incur a cost unless it was reasonable and prudent. If the utility were required to justify each expense item composing the cost of service as reasonable and prudent with independent evidence to that effect, the ratemaking process would be impossible to administer. Once the utility proves it has incurred the item of test year expense, a party contesting reasonableness and prudence has the burden of presenting affirmative evidence of unreasonableness. Thereafter, the burden shifts back to the utility to rebut the evidence of unreasonableness.

As the North Carolina Supreme Court has stated in a case addressing the issue of burden of proof with respect to utility payments to an affiliated third party for items of regulated cost of service, where Commission scrutiny should be far more intense:

> Although it always has the authority to do so, in the absence of contradiction or challenge by affirmative evidence offered by any party to the proceeding, the Commission has no duty to make further inquiry or investigation into the reasonableness of charges or fees paid to affiliated companies.
>
> * * *
>
> The 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 on the basis that they are exorbitant, unnecessary, wasteful, extravagant, or incurred in abuse of discretion or in bad faith or such expenses exceed either the cost of the same or similar goods or services on the open market or the cost similar utilities pay to their affiliated companies for the same or similar goods or services.

State ex rel. Utilities Commission v. Intervenor Residents of Bent Creek/Mt. Carmel, 305 N.C. 62, 75-76, 286 S.E.2d 770, 778-79 (1982).

In this case, the Public Staff has produced no affirmative evidence that the $28,069 is unreasonable or imprudent. Instead, it rests its proposed disallowance on Aqua NC's alleged inability to offer proof of reasonableness for actions taken or not taken four years ago. This misapplication of the burden of proof must result in a rejection of the adjustment.

A requirement that the Public Staff's misapplication of the burden of proof be called out in the context of the USC contract is particularly important. Leasing of space on elevated water tanks to antenna owners, such as cellular telephone companies, is not an activity a water utility like Aqua NC is required to undertake under its public utility responsibilities. If Aqua NC had chosen not to enter into such leases or if it determines to discontinue this practice, the Commission is powerless to require otherwise. When water utilities first entered into antenna leases they did so, with some justification, on the assumption that the revenues and expenses would be below the line. The net revenues would accrue to the stockholders. The losses would be borne by the stockholder also.

At the Public Staff's request, the Commission has rejected utility requests to allow stockholders to retain the antenna lease revenues. The theory relied upon to approve this rejection is that the ratepayers are reimbursing the stockholder for its investment in the elevated tank to which the antennas are affixed through depreciation expense recovered through rates, thereby justifying attributing all of the net antenna lease revenues to the ratepayers. Aqua NC does not contest the notion that the ratepayers should receive the actual net lease revenues from the unregulated leases. However, the Public Staff now seeks in addition to disallow actual expense in the unregulated endeavor Aqua NC incurred to generate the revenues. So, under the Public Staff theory, not only is the stockholder denied any of the net revenues from its decision to lease space on its tanks, but it is asked to provide net revenues to the ratepayer in excess of the revenues actually received. The ratepayers receive the actual net revenues, and Aqua NC kicks in $28,069 to boot.

Were the Commission to agree with the Public Staff, this would provide a strong incentive to Aqua NC and other water companies to enter into no additional antenna leases and to terminate existing leases as soon as possible. This is a classic case of looking the gift horse in the mouth. Furthermore, were Aqua NC to enter into third-party non-regulated contracts that produced net losses instead of net gains, the Commission would not permit recovery of the losses through rates. Under the Public Staff logic, this is a case of "heads I win, tails you lose."

The majority resolves this issue on the basis that Aqua NC's evidence of reasonableness is more persuasive than the Public Staff's evidence to the contrary but, inconsistently in my view, then urges the Company in the future to pay particular attention to the Public Staff's concerns. The Public Staff has no evidence; only concerns. While the Commission is well within its authority to require Aqua NC to provide additional evidence in the future in the appropriate case, I maintain that its admonitions are misplaced in this context. Were I Aqua NC faced with the suggestion that I might lose not only net revenue but be required to eat expense from non-regulated endeavors because my proof is inadequate, I would determine that the expedient step to take would be to avoid antenna leases at all costs. Moreover, Aqua NC's contract with USC is for 10 years with possible extensions. Under the USC contract the 30% commission is fixed. Aqua NC cannot go back and conduct a cost/benefit analysis for a

2007 contract. Any future negotiations with antenna lessees are between USC and the lessee, not Aqua NC. The prudence and reasonableness of USC's terms with future lessees will be based on USC's actions, not Aqua NC's. As USC's commission is based on the level of lease payments from the lessee, USC has every incentive to maximize the payments it and Aqua NC will receive. Consequently, the die is cast, and it will be difficult for Aqua NC to change its contract with USC in the future or to provide any of the evidence the majority identifies. In my view, the Commission should resolve this issue on the basis of the Public Staff's failure to produce evidence of unreasonableness and avoid providing incentives to Aqua NC to discontinue subsidizing rates to its water customers through antenna lease payments.

\s\ Edward S. Finley, Jr.
Chairman Edward S. Finley, Jr.

WATER AND SEWER – SALE/TRANSFER

DOCKET NO. W-218, SUB 325
DOCKET NO. W-218, SUB 327
DOCKET NO. W-218, SUB 319

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. W-218, SUB 325

In the Matter of Application by Aqua North Carolina, Inc., 202 MacKenan Court, Cary, North Carolina 27511, for Authority to Transfer the Water and/or Sewer Utility Systems Serving the Brantley Oaks, McCarron, Stone Mountain, Timberlands, Willows Creek, Reedy Creek Plantation, and Satterwythe Place/Alderwood Service Areas in Mecklenburg County, North Carolina to the City of Charlotte, which is Exempt from Commission Regulation DOCKET NO. W-218, SUB 327 In the Matter of Application by Aqua North Carolina, Inc., 202 MacKenan Court, Cary, North Carolina 27511, for Authority to Discontinue Public Utility Service to Windsor Oaks Subdivision in Wake County, North Carolina DOCKET NO. W-218, SUB 319 In the Matter of Application by Aqua North Carolina, Inc., 202 MacKenan Court, Cary, North Carolina 27511, for Authority to Increase Rates for Water and Sewer Utility Service in All of Its Service Areas in North Carolina	ORDER DETERMINING REGULATORY TREATMENT OF GAIN ON SALE

HEARD: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina on Wednesday, August 24, 2011 at 9:00 a.m.

BEFORE: Commissioner Bryan E. Beatty, Presiding; and Commissioners Lorinzo L. Joyner, Susan W. Rabon, ToNola D. Brown-Bland, and Lucy T. Allen

APPEARANCES:

For Aqua North Carolina, Inc.:

Daniel C. Higgins, Burns, Day & Presnell, P.A., Post Office Box 10867, Raleigh, North Carolina 27608, and Jo Anne Sanford, Sanford Law Office, PLLC, Post Office Box 28085, Raleigh, North Carolina 27611-8085

For Charlotte-Mecklenburg Utilities:

M. Gray Styers, Jr. and Karen M. Kemerait, Styers & Kemerait, PLLC, 1101 Haynes Street, Suite 101, Raleigh, North Carolina 27604

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: On March 23, 2011, in Docket No. W-218, Sub 325, Aqua North Carolina, Inc. (Aqua NC or Company) filed an application with the Commission for authority to transfer the franchise for providing water and sewer utility service in the following subdivisions: Brantley Oaks, McCarron, Stone Mountain, Timberlands, Willows Creek, Reedy Creek Plantation, and Satterwythe Place/Alderwood, (collectively referenced as the Willows Creek and McCarron Systems) in Mecklenburg County, North Carolina, to Charlotte-Mecklenburg Utilities (CMU), a department of the City of Charlotte (City), which is exempt from Commission regulation. At that time, Aqua NC was serving 263 water customers and 910 sewer customers in those subdivisions. On June 27, 2011, the Commission issued an Order approving the transfer.

On May 20, 2011, in Docket No. W-218, Sub 327, Aqua NC filed an application with the Commission seeking authority to discontinue the provision of water and sewer service to customers in the Windsor Oaks Subdivision in Wake County, North Carolina. The Town of Cary annexed the Windsor Oaks Subdivision and installed mains that paralleled Aqua NC's water and sewer mains in that subdivision, where Aqua NC had once served 90 customers. On July 28, 2011, the Commission issued an Order authorizing Aqua NC to abandon its water and sewer utility systems serving that subdivision effective September 1, 2011. By letter dated September 12, 2011, Aqua NC notified the Commission that all its former Windsor Oaks customers had been connected to and were being served by the Town of Cary.

On January 21, 2011, in Docket No. W-218, Sub 319, Aqua NC filed an application with the Commission seeking authority to increase rates for water and/or sewer public utility service in all of its service areas in North Carolina. At that time, Aqua NC was serving approximately 72,660 water customers and 15,260 sewer customers in its service areas, which are located across 48 counties in North Carolina. On February 8, 2011, the Commission issued an Order declaring that matter to be a general rate case pursuant to G.S. 62-137. On November 3, 2011, the Commission issued an Order granting partial rate increase, reaffirming the rates approved in the Notice of Decision and Order issued September 13, 2011 on a provisional basis, and ordering that those provisional rates would be adjusted to reflect the Commission's rulings in Docket No. W-218, Sub 325.

On April 28, 2011, in Docket No. W-218, Sub 325, the Commission issued an Order requiring customer notice, specifying that the matter may be determined without public hearing if no significant protests were received subsequent to customer notice. On May 6, 2011, Aqua NC filed a Certificate of Service notifying the Commission that the required customer notice had been provided. No customer protests were received.

On June 22, 2011, CMU filed a petition to intervene. By Order issued June 30, 2011, the Commission granted CMU's petition to intervene.

On June 27, 2011, the Commission issued its Order Approving Transfer, Canceling Franchises, and Scheduling Hearing. The matter was set for hearing on "the issue of how, if at all, the remaining ratepayers should be protected from an adverse impact" resulting from the transfer.

On June 30, 2011, Aqua NC and the Public Staff – North Carolina Utilities Commission (the Public Staff) filed a Joint Stipulation agreeing that (1) the rate base, expenses, and revenues for the systems being transferred would be removed from Aqua NC's pending general rate case, Docket No. W-218, Sub 319; (2) the rate base, expenses, and revenues for the Windsor Oaks systems being abandoned in Docket No. 218, Sub 327, would be removed from Aqua NC's pending general rate case; and (3) the rates to be approved in the general rate case would be provisional and subject to later adjustment to reflect the Commission's treatment of gain on sale for the transferred systems, the treatment of loss for the Windsor Oaks abandonment, the removal of rate base, revenues, and expenses for the transferred and abandoned systems, and any other Commission rulings in the transfer proceeding that would affect Aqua NC's rates.

On June 13, 2011, Aqua NC filed a Certificate of Service notifying the Commission that the required customer notice had been provided, as required by the June 27, 2011 Order approving the transfer.

On July 22, 2011, the Public Staff filed the testimony and exhibit of Katherine A. Fernald, Supervisor, Water Section, Public Staff Accounting Division. On July 27, 2011, the Commission granted Aqua NC's and the Public Staff's joint motion for extension of time to file Aqua NC's testimony and the Public Staff's rebuttal testimony. On August 3, 2011, CMU filed the testimony and exhibits of Barry D. Shearin, Chief Engineer for CMU, and Kimberly S. Hibbard, General Counsel of the North Carolina League of Municipalities. On August 8, 2011, Aqua NC filed the testimony of Thomas J. Roberts, President and Chief Operating Officer of Aqua NC, and the testimony and exhibits of Shannon V. Becker, Controller of Aqua NC. On August 17, 2011, the Public Staff filed the rebuttal testimony of Ms. Fernald.

On October 3, 2011, Aqua NC and CMU filed a motion requesting that the Commission grant an extension of time for the filing of proposed orders and/or briefs until October 11, 2011. On October 4, 2011, the Commission issued an Order granting the extension of time. On October 11, 2011 the parties filed their proposed orders and/or briefs.

The matter was heard as scheduled on August 24, 2011. There were no public witnesses. The expert witnesses who had filed testimony presented their testimonies and exhibits to the

Commission. A summary overview of selected numerical data referenced in this proceeding is provided in Appendix A, attached hereto.

Based upon the foregoing, the evidence presented at the hearing, and the entire record in this matter, the Commission now makes the following

FINDINGS OF FACT

1. Aqua NC is a corporation duly organized under the laws of and is authorized to do business in the State of North Carolina. Aqua NC is a franchised public utility providing water and/or sewer utility service to customers in North Carolina.

2. Effective June 30, 2009, the City of Charlotte, a municipal corporation, annexed certain areas in the eastern part of Mecklenburg County described as the Hood Road North and Hood Road South areas. At that time, Aqua NC was providing water and sewer public utility service in some parts of the Hood Road North and the Hood Road South areas through its Willows Creek and McCarron Systems service area, which served the Timberlands, Satterwythe Place/Alderwood, Brantley Oaks, Willows Creek, Stone Mountain, Reedy Creek Plantation and McCarron subdivisions.

3. The City of Charlotte's CMU Department approached Aqua NC in early 2009, prior to the Hood Road North and Hood Road South annexations, to discuss the possible sale by Aqua NC to CMU of the Company's Willows Creek and McCarron Systems. CMU sought to acquire these systems from Aqua NC in order to avoid the expense and disruption of constructing new, redundant lines and duplicating the existing facilities in these annexed areas.

4. Pursuant to North Carolina law and the City of Charlotte's utilities facilities extension policy, the City is required to extend water and sewer facilities into the annexed areas to allow annexed property owners to obtain water and sewer services from the City within two years of the effective date of an annexation.

5. CMU and Aqua NC executed an agreement-of-sale contract, effective March 1, 2011, whereby CMU agreed to pay a purchase price of $4,167,500 for the water and sewer public utility systems of Aqua NC in its Willows Creek and McCarron Systems service area in Mecklenburg County. The gain from the sale of these water and sewer systems is $3,162,447. There are approximately 263 water customers and 910 sewer customers on the Willows Creek and McCarron Systems representing 0.49% and 7.06% of Aqua NC's total water and sewer customers, respectively.[1]

6. The transfer of the Willows Creek and McCarron Systems in Mecklenburg County is in the best interest of the customers on those systems and the City. The transfer was approved by the Commission by Order issued June 27, 2011, and the transaction between CMU and Aqua NC closed on June 29, 2011.

[1] The total number of Aqua NC customers is 66,977, which is comprised of 54,090 water customers and 12,887 sewer customers. These customer numbers exclude the Company's Fairways water and sewer customers and Brookwood water customers, since those systems have separate respective rates.

7. The issue of treatment of gain on sale for water and sewer utility companies is a matter that has been previously addressed by the Commission in a number of prior dockets. In particular, in Docket Nos. W-354, Subs 133 and 134, in the September 7, 1994 Order Determining Regulatory Treatment Of Gain On Sale Of Facilities, the Commission concluded that "in future proceedings, the Commission will follow a policy, absent overwhelming and compelling evidence to the contrary, of assigning 100% of the gain or loss on the sale of water and/or sewer utility systems to utility company shareholders." Since 1994, the Commission has applied this policy of awarding 100% of the gain or loss on sale of water and sewer systems to the utility company's shareholders. Although this allocation has been challenged in only a few cases during this 17-year period, the Commission has not found sufficient evidence in the past proceedings, excluding the companion proceeding in Docket No. W-354, Sub 331, involving Carolina Water Service of North Carolina, Inc., (CWS NC), to merit a deviation from the presumptive allocation.

8. The pertinent facts with respect to Aqua NC's transfer of its Willows Creek and McCarron Systems to CMU are not materially different from those with respect to the sales which were the subject of the Commission's prior rulings on treatment of gain on sale in connection with water and sewer transfer applications decided in 1994 and thereafter. An exception to the Commission's policy of assigning 100% of the gain on sale to water and sewer utility company shareholders is not warranted in this proceeding, as the larger public interest is best served by continuing such policy. Accordingly, the gain on sale of the Willows Creek and McCarron Systems should be assigned 100% to Aqua NC's shareholders.

9. The Town of Cary annexed the Windsor Oaks Subdivision and installed mains that paralleled Aqua NC's water and sewer mains in that subdivision, where Aqua NC had once served 90 customers. As a result, Aqua NC has incurred a loss due to the abandonment of the Windsor Oaks water and sewer systems. The Windsor Oaks sewer system was not in Aqua NC's uniform rate structure. The Windsor Oaks water system was in Aqua NC's uniform rate structure. The loss on abandonment of the Windsor Oaks systems should be assigned 100% to Aqua NC's shareholders.

10. The applicable rate base, revenues, and expenses, including appropriate accumulated deferred income taxes (ADIT) related to the Willows Creek and McCarron Systems being transferred to CMU, as well as the rate base, revenues, and expenses, including ADIT, associated with the abandonment of the Windsor Oaks systems, should be removed from and not taken into account in setting rates for Aqua NC in its rate case proceeding in Docket No. W-218, Sub 319. The rates approved in that docket, per the September 13, 2011 Notice of Decision and Order, are provisional rates and should be adjusted to reflect the Commission's findings in this Order.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

The evidence supporting this finding of fact is contained in the Company's filings in this docket and in the Commission's records. This finding is primarily jurisdictional and informational and is uncontested.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 2 THROUGH 4

The evidence supporting these findings of fact is found in the testimony of Aqua NC witness Roberts and CMU witness Shearin. These are principally factual matters that are generally uncontested and noncontroversial.

Aqua NC witness Roberts testified that the systems which are the subject of the CMU transfer are Aqua NC's water and sewer assets in the Willows Creek and McCarron Systems, which serve the Timberlands, Satterwythe Place/Alderwood, Brantley Oaks, Willows Creek, Stone Mountain, Reedy Creek Plantation, and McCarron subdivisions. Witness Roberts stated that some of these systems were part of the assets acquired when Aqua NC purchased Heater Utilities, Inc. (Heater), where Aqua NC paid a price greater than the net book value of the acquired assets, with the expectation that it would earn on its investment in these systems over a long period of years. The Willows Creek and McCarron Systems are for the most part located in parts of the Hood Road North or Hood Road South areas recently annexed by the City of Charlotte. Aqua NC's agreement with the City's request to transfer these systems to CMU, allowed Aqua NC to avoid the risk that CMU would parallel these systems.

CMU witness Shearin testified that effective June 30, 2009, the City of Charlotte annexed certain areas in the eastern part of Mecklenburg County, described as the Hood Road North and Hood Road South areas, and sought to purchase Aqua NC's water and sewer utility systems serving its Willows Creek and McCarron Systems so that CMU could avoid the expense and disruption of constructing new, redundant lines and duplicating the existing facilities in these annexed areas. Witness Shearin also stated that of the seven subdivision systems purchased, one of those, the Willows Creek Subdivision, was not located within the Hood Road North or South annexation areas. However, he explained that the Willows Creek Subdivision was included in the purchase because that subdivision contains the wastewater treatment plant that serves the other subdivisions that were in the annexation area. Witness Shearin emphasized that CMU is obligated to provide water and sewer services to residents in the annexed areas in accordance with North Carolina law; and that this must be done within two years of the effective date of the annexation.

Further, witness Shearin observed that the decision to try to acquire these systems from Aqua NC was made over two and a half years ago, as CMU commenced discussions with Aqua NC in early 2009, before the area was annexed in June 2009. Witness Shearin also testified that CMU approached Aqua NC; Aqua NC did not approach CMU regarding the sale of these systems.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence supporting this finding of fact is contained in the Company's application for transfer and the testimony and exhibits of Public Staff witness Fernald and Company witness Becker and is uncontested. Witness Fernald testified that the gross of tax gain from the sale of the subject water and sewer systems to the City is $3,162,447, which consists of the purchase price for the systems of $4,167,500 less the net book value of the assets sold of $932,423, construction work in progress of $22,276, and selling costs and legal fees of $50,354. Company witness Becker agreed that the total gain on sale for the water and sewer systems is $3,162,447.

Thus, the Commission concludes that the sale price of $4,167,500 generated a gain on sale for the water and sewer systems of $3,162,447.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence regarding this finding of fact is contained in the Company's application for transfer, the Commission's files, and in the testimony and exhibits of Public Staff witness Fernald, Company witness Roberts, and CMU witnesses Shearin and Hibbard. Witness Fernald testified that the ratepayers on the systems sold to CMU will benefit from a reduction in their rates; consequently the Public Staff believes that the transfer of these systems is in the interest of those customers.

Witness Roberts stated that the transfer of these systems to CMU allowed Aqua NC to avoid the risk that CMU would parallel the systems. Witness Roberts testified that if CMU decided to parallel the systems, then it would render the systems useless. Further, witness Roberts asserted that the sale of these systems to CMU is in the public interest because CMU will not have to dig up the streets and disrupt neighborhoods to parallel Aqua NC's service lines; and customers would not be required to pay CMU's connection fees to the new lines. The Commission approved the transfer of the Willows Creek and McCarron Systems to CMU by Order dated June 27, 2011. Witness Roberts testified that the Company and CMU closed on this transaction on June 29, 2011. Further, witness Roberts explained that Aqua NC had no escape clause in its contract with CMU that conditioned the closing on satisfactory gain on sale treatment by the Commission, so the transaction was completed.

Witness Shearin testified that the former Aqua NC customers who became CMU customers realized a substantial reduction in their monthly water and sewer bills due to the fact that CMU's rates are significantly less than Aqua NC's rates. In particular, witness Shearin explained that under CMU rates, the transferred customers of Aqua NC will experience a decrease in their average monthly metered water and sewer bill from $101.95 to $47.57, based on 4,925 gallons usage. And the transferred customers who received only sewer service from Aqua NC will see a decrease in their average monthly sewer bill from $63.33 to $33.94 based on 4,925 gallons usage. Furthermore, he testified that the Aqua NC transferred customers will not be required to pay a connection fee to the City.

Witness Shearin also stated that larger public municipal systems provide economies of scale and, consequently, typically have lower rates. In addition, he explained that municipal systems generally have better system reliability, better production facilities, more water storage and a water source from surface water, and can provide better fire protection. Witness Shearin further observed that municipal systems usually have greater financial stability and strength and access to tax-exempt capital and other advantageous financing arrangements. Witness Shearin noted that since Aqua NC already owned water and sewer utility systems in the annexation area, CMU wanted to purchase Aqua NC's Willows Creek and McCarron Systems so that it could avoid the expense and disruption of constructing new, redundant lines and duplicating facilities in the annexed areas.

Witness Hibbard agreed with witness Shearin's testimony concerning the benefits to water and sewer customers of being served by municipal systems. Witness Hibbard explained that it is a win-win-win situation when - municipalities are spared the unnecessary expense of constructing redundant, duplicative systems; utilities are able to sell systems that might otherwise become underutilized; and the utility's customers can receive the benefits of service from a municipal system including lower rates.

Consistent with the position of all parties, the Commission finds and concludes that the transfer of the Willows Creek and McCarron Systems considered in this docket is in the best interest of the customers on those systems. In addition, the testimony of CMU witnesses supports the finding that the transfer is in the best interest of the City, and the evidence from other witnesses was not contradictory to this finding. It was for these same reasons that the Commission approved the transfer by Order dated June 27, 2011. However, in that Order the Commission scheduled a hearing on "the issue of how, if at all, the remaining [Aqua NC] ratepayers should be protected from an adverse impact" of the transfer. That issue, which affects Aqua NC's shareholders and remaining ratepayers, is addressed below.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence regarding this finding of fact is contained in the Commission's files and decisions in the dockets referenced hereinafter, which are pertinent and relevant to the issue presented in this present proceeding, and in the testimony of Public Staff witness Fernald and Aqua NC witness Roberts. The Commission is of the opinion that a review of the history of the evolution of the Commission's policy analyses and decisions as to treatment of gain on sale of water or sewer utility systems is beneficial and insightful to the instant analysis and the rulings being determined in the present proceeding. Accordingly, the following overview is provided.

In 1990, CWS NC was confronted by efforts of three municipal or governmental entities to acquire three of its systems. The City of Charlotte, through CMU, sought to acquire CWS NC's Beatties Ford system in Mecklenburg County. The Eastern Wayne Sanitary District sought to acquire CWS NC's Genoa system in Wayne County, and the Town of New Bern sought to acquire CWS NC's Riverbend system in Craven County. (Order Determining Regulatory Treatment on Gain on Sale of Facilities, October 16, 1990, Docket Nos. W-354, Subs 82, 86, 87, and 88.) CWS NC entered into tentative contracts to sell the three systems and requested that the Commission rule on the issue of whether the Company's stockholder should be permitted to retain 100% of the gain on sale.

In Docket Nos. W-354, Subs 82, 86, 87, and 88, which involved CWS NC's sale of systems to CMU, the Public Staff and the Attorney General advocated giving 100% of the gain on sale to the Company's ratepayers. After an evidentiary hearing, the Commission held that the gain should be split 50/50 between the Company's ratepayers and its shareholders. The Commission reasoned that both the shareholders and the ratepayers bore part of the risk in maintaining the systems and both should share equally in the profits upon disposition through sale.

As CWS NC's contracts for the sale of those three systems were conditioned on the Commission's ruling, each of the three contracts was renegotiated in light of the Commission's ruling. CWS NC sought to obtain a higher price for the systems since the Commission's ruling denied the Company half of the profit for which it had initially bargained. CMU paid an increased price for the Beatties Ford system. While the Eastern Wayne Sanitary District determined that it would rather parallel the Genoa system than pay more than what it had initially bargained to pay, it ultimately paid less than the tentative contract price. New Bern was unwilling to pay an increased price, and the sale of the Riverbend system to New Bern did not take place.

In 1992, in the aftermath of the CWS NC gain on sale cases, Heater sold the system in the Pinewood Subdivision to the City of Goldsboro and sought to discontinue service to the Country Acres Subdivision in Wayne County. In Docket Nos. W-274, Subs 71 and 72, Heater asked the Commission to permit it to retain 100% of the gain on sale. An Order Determining Regulatory Treatment of Gain on Sale and Loss on Abandonment of Facilities was issued May 21, 1993. The Commission affirmed the rationale it had relied upon in the 1990 CWS NC cases and ruled that the gain should be shared 50/50 between shareholders and ratepayers. While the Commission ruled that the evidence was not sufficiently different to warrant a different result, four members of the Commission filed concurring or dissenting opinions wherein they expressed concerns that past decisions may have discouraged or certainly not encouraged the sale of systems to municipal operators, to the detriment of the public interest.

In 1993 and 1994, CWS NC again faced requests that it sell systems in Mecklenburg County to CMU. In light of the differences of opinion expressed in the Heater Docket Nos. W-274, Subs 71 and 72, CWS NC again requested that the Commission address the gain on sale issue as a result of transfer applications filed in Docket Nos. W-354, Subs 133 and 134. In that proceeding, CWS NC argued that regulatory treatment denying the utility's shareholder the opportunity to retain the gain, including gain-splitting, discouraged sales of systems to municipal or governmental operators. The Public Staff argued that the Commission should adhere to the ruling from the earlier cases and split the gain equally between the Company's shareholders and its remaining ratepayers.

In Docket Nos. W-354, Subs 133 and 134, the Commission held, in the September 7, 1994 Order Determining Regulatory Treatment, that in future cases, where a question was raised about the treatment of a gain resulting from the sale of water or sewer utility assets, the Commission would allocate 100% of the gain on the sale to shareholders unless there was overwhelming and compelling evidence that the total amount of the gain should not be allocated to the shareholders.

In that Order the Commission stated the following:

> The gain splitting policy [that was in effect prior to the Commission's decision in this docket] must also be examined within the context of the impact of the policy on the process through which the ownership of private water and sewer systems customarily change hands. Under the most common pattern, the private system is installed by a developer with no interest or ability to operate and maintain the system over the long term. Companies like CWS, with capital and operational expertise and with the long-term desire to operate the systems, acquire them from developers or small operators. Over time, as municipal development and expansion take place, opportunities often arise through which a municipality or governmental system takes over from the private utility operator. At each step,

> the customer benefits from the transfer of ownership. Water quality may improve, and the potential exists for lower rates. That being the case, the Commission should not impose economic barriers to the orderly transfer of water systems to municipal entities, as was inadvertently done in the Riverbend situation.
>
> If economic incentives are removed so that this succession of ownership becomes inadvisable, customers are denied those benefits. If companies like CWS are prevented from retaining the gain on sale in North Carolina, a substantial incentive is removed for those companies to buy systems from developers or small, undercapitalized operators in the first instance. Likewise, a substantial incentive is removed to negotiate to sell systems to municipal or governmental entities. At a minimum, the sale price is artificially increased above the fair market based price to adjust for the payment of part of the gain to customers. The result is harm to consumers because the natural progression of transfer of ownership to the most efficient provider is disrupted. These harmful consequences are clearly not in the public interest.
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> . . .
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> [T]he Commission rejects the Public Staff's reliance upon the prior [Carolina Water Service] and Heater [Utilities] decisions for purposes of these consolidated dockets and hereby **announces that in future proceedings, the Commission will follow a policy, absent overwhelming and compelling evidence to the contrary, of assigning 100 percent of the gain or loss of the sale of water and/or sewer utility systems to utility company shareholders.** In so deciding, the Commission intends to encourage, to the maximum extent possible, the sale of water and sewer systems to municipalities and other government-owned entities. It is, and shall continue to be, the policy of this Commission to take such actions as will encourage the larger water and sewer utilities with greater operational and capital resources, including governmental entities, to acquire the smaller, undercapitalized, less efficient systems. Such policy serves the public interest by promoting efficiencies through economies of scale and generally results in more favorable rates and an enhanced quality of service.

(1994 Order Determining Regulatory Treatment, Pages 4, 5, and 7) (Emphasis added.)

Further, the Commission specifically noted therein that "[w]ith the benefit of hindsight, the Commission can now see that the policy to split the gains or losses on sales of water and/or sewer systems has had a negative impact on the public good." In that Order the Commission cited the harmful consequences of its decision with respect to prior cases where proposed sales to municipal/governmental owners either were not consummated, or where the utility demanded a higher price from the municipal purchaser in order to sell the systems.

The Public Staff moved for reconsideration of the 1994 Order Determining Regulatory Treatment in Docket Nos. W-354, Subs 133 and 134. In its November 14, 1994 Order on Reconsideration, the Commission denied the Public Staff's motion for reconsideration, reaffirmed its findings and conclusions in the Order Determining Regulatory Treatment previously issued therein, and provided the following further insight regarding its decision to assign 100% of gain or loss on sale to the utility's shareholders:

> The Commission [in its September 7, 1994 Order] further concluded that, with the benefit of hindsight, the previous policy to equally share or split the gains or losses on sales of water and/or sewer systems has had a negative impact on the public good and is contrary to the public interest. That being the case, the Commission announced that it would henceforth **'follow a policy, absent overwhelming and compelling evidence to the contrary, of assigning 100% of the gain or loss on the sale of water and/or sewer utility systems to utility company shareholders.** In so deciding, the Commission intends to encourage, to the maximum extent possible, the sale of water and sewer systems to municipalities and other government-owned entities. It is, and shall continue to be, the policy of this Commission to take such actions as will encourage the larger water and sewer utilities with greater operational and capital resources, including governmental entities, to acquire the smaller, under-capitalized, less efficient systems. Such policy serves the public interest by promoting efficiencies through economies of scale and generally results in more favorable rates and an enhanced quality of service.'

(Order on Reconsideration, issued November 14, 1994, Pages 1 and 2) (Emphasis added.)

The Public Staff appealed the Commission's rulings in those dockets. *State ex rel Utilities Commission v. Public Staff-North Carolina Utilities Commission, supra.* The North Carolina Court of Appeals (Court) affirmed the Commission's decisions, ruling that the findings and conclusions set forth by the Commission supported the decision to allow CWS NC to retain 100% of the gain on sale and that the record before the Commission contained substantial, material, and competent evidence to support the Commission's findings. The Court concluded that

> a reasonable mind would regard the testimony of Daniel and Fernald, along with other materials contained in the record, to adequately support a conclusion that the best interests of the public would be served by allowing CWS to keep 100 percent of the gain on sale of the Farmwood B and Chesney Glen systems. The evidence showed a policy of equally splitting gains on sale would result in a higher purchase price for the Farmwood B system, causing a greater burden for Charlotte-Mecklenburg taxpayers. Also, the contract stated that if CWS was required to share more than 50 percent of the gain with the ratepayers, then the sale could be called off. The evidence also showed the beneficial transfers of privately held utilities to municipal systems had been hampered by a policy of splitting gain on sale. In this case, if CWS had refused to sell the facilities, CMUD would have been forced to duplicate the existing facilities at a high cost. Further, a policy of assigning 100 percent of the gain to the shareholder encourages CWS to make further investments in other smaller water systems, some of which may be undercapitalized or poorly run.

The Court also disagreed with the Public Staff's contention that the Commission's Order was arbitrary and capricious. The Court held that "the Commission gave fair and careful consideration to the issues before it, and that the Commission's final decision was the product of reasoning and the exercise of its judgment." The Court found that "the evidence that is contained in the record to be sufficient to support the Commission's order that CWS retain all of the gain on sale of the Farmwood B and Chesney Glen systems." Lastly, the Court stated that

> Public Staff assigns as error the Commission's statement that '[I]n future proceedings, the Commission will follow a policy, absent overwhelming and compelling evidence to the contrary, of assigning 100% of the gain or loss on the sale of water and/or sewer utility systems to utility company shareholders.' However, this issue is not properly before this Court and we need not decide it.

App 123 N.C. App. at 50.

CWS NC subsequently requested a determination from the Commission as to the regulatory treatment the Commission would authorize in connection with CWS NC's proposed transfer of additional systems to CMU. The Public Staff again advocated that the gain on sale should be shared to mitigate any adverse impact on CWS NC's remaining customers. Again in 1995,[1] and twice in 1996, the Commission reaffirmed its policy of assigning 100% of the gain or loss on the sale of water and/or sewer utility systems to utility company shareholders unless overwhelming and compelling evidence was presented that would support a different distribution.[2]

In the first such ruling in 1996, Order Determining Regulatory Treatment, Docket Nos. W-354, Subs 143 and 145 (March 29, 1996), the Commission stated that it had "long been concerned over the '"troubled water system problem"' and sought to "facilitate the orderly transfer from developers to investor-owned utilities and from investor-owned utilities to municipalities and governmental entities." The Commission concluded that splitting the gain on sale created an economic barrier to achieving these public interests. Additionally, the Commission explicitly rejected the assertion that the Commission's position does not influence the selling price of a utility system as "illogical." The Commission concluded its order by finding that "no evidence, much less overwhelming and compelling evidence, has been presented in this proceeding to warrant the departure from the Commission's current gain on sale position and therefore concludes that the Company should retain 100 percent of the gain on sale."

[1] *See* Docket No. W-354, Sub 140, Order Approving Transfer and Determining Regulatory Treatment of Gain on Sale, February 3, 1995. The Public Staff appealed that ruling, arguing that the Commission's stated intent to apply its policy on treatment of gain on sale exceeded its statutory authority. *State ex rel Utilities Commission v. Public Staff-North Carolina Utilities Commission*, 123 N.C. App. 623, 473 S.E. 2d 661 (1996). The North Carolina Court of Appeals affirmed the Commission's decision adopting the policy of allocating 100% of the gain on sale to the utility company shareholders.

[2] On March 29, 1996, in Docket Nos. W-354, Subs 143 and 145, the Commission reaffirmed that policy in its Order Determining Regulatory Treatment of Gain on Sale. The Public Staff appealed that ruling to the North Carolina Court of Appeals, but later withdrew its appeal. The Commission again reaffirmed its gain on sale policy on August 5, 1996, in Docket Nos. W-354, Subs 148-151 and 155-157, in its Order Determining Regulatory Treatment of Gain on Sale.

In the second such ruling in 1996, Order Determining Regulatory Treatment, Docket Nos. W-354, Subs 148-151 and 155-157 (August 5, 1996), the Commission rejected the Public Staff's arguments that (1) the Commission's gain on sale policy did not influence the transfer of the utility systems because CMUD was obligated to extend its lines anyway; (2) CWS NC's contracts were not contingent on treatment of gain on sale; and (3) the loss of customers would reduce economies of scale, but sharing the gain on sale would mitigate the impact. The Commission once again concluded "that the Public Staff has failed to present any new evidence of sufficient probative value to persuade the Commission to alter its current position on the gain on sale issue." The Commission reaffirmed its position of encouraging the "orderly transfer of water systems from developers and small owners to reputable water utilities like CWS and from reputable water utilities to municipalities and other governmental owners." It further stated that "[t]he Commission has endeavored to establish a generic policy that could be relied upon by affected parties in the State of North Carolina so that they could plan their business accordingly." The Commission also concluded that the loss of customers and allocation of costs across a reduced customer base did not constitute sufficient evidence to alter its policy of allocating 100% of the gain on sale to utility shareholders. Furthermore, the Commission stated

> The Commission finds that no new evidence, **much less overwhelming and compelling evidence**, has been presented in this proceeding to warrant the departure from the Commission's current gain on sale position and therefore concludes that the Company should retain 100 percent of the gain on sale. In so concluding, the Commission believes that the current position better serves and promotes the public interest and should be followed in these dockets. (Emphasis added.)

In its subsequent Motion for Reconsideration of the Commission's Order in Docket Nos. W-354, Subs 148, *et al*, the Public Staff argued that the Commission had ignored its argument regarding the impact of the sale of utility systems on the rates of the remaining customers as a grounds for assigning a portion of the gain to ratepayers. By its Order on Motion for Reconsideration (November 27, 1996), the Commission denied the Public Staff's Motion.

In summary, the Commission's analysis of this issue has evolved over the years. The Commission's current policy, as established in the 1994 Order Determining Regulatory Treatment, in Docket Nos. W-354, Subs 133 and 134, is that "the Commission will follow a policy, absent overwhelming and compelling evidence to the contrary, of assigning 100% of the gain or loss on the sale of water and/or sewer utility systems to utility company shareholders." Furthermore, the Commission "has endeavored to establish a generic policy that could be relied upon by affected parties in the State of North Carolina so that they could plan their business accordingly." Since 1994, the Commission has applied this policy.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence regarding this finding of fact is contained in the Company's application for transfer, the Commission's files, and in the testimony and exhibits of Public Staff witness Fernald, Company witnesses Roberts and Becker, and CMU witnesses Shearin and Hibbard.

WATER AND SEWER – SALE/TRANSFER

The Public Staff believes that gains and losses should continue to be assigned 100% to stockholders except in cases where there is an adverse impact to the remaining ratepayers. The Public Staff contended that it is appropriate to address that adverse impact in each case. The Public Staff is of the opinion that the portion of the gain necessary to offset the negative impact should be assigned to ratepayers. Public Staff witness Fernald testified that a material negative impact is a change of one cent or more.

Witness Fernald observed that the ratepayers on the transferred systems will benefit from a reduction in their rates, so the transfer is in the interest of those customers. However, she also pointed out that removing those systems from uniform rates in Aqua NC's pending rate case will have a negative impact on the remaining ratepayers.

Witness Fernald contended that circumstances have changed since the Commission decided to assign stockholders 100% of the gain on sale of water and sewer systems. The Public Staff opined that in the past the large regulated water and sewer companies who were selling systems, such as CWS NC and Heater, were growing in customer base at such a rate that the addition of new customers in other areas would quickly offset the loss of the customers being transferred. Furthermore, witness Fernald observed that in recent years the rate of customer growth for water and sewer companies, including Aqua NC has declined. As a result, witness Fernald maintained that the increase in the cost of service for the remaining ratepayers due to the loss of the systems sold to the City of Charlotte will not be so quickly offset by customer growth. The Public Staff also argued that the detrimental impact on the remaining ratepayers will be especially acute for sewer service since 7.06% (910 customers) of the customer base under uniform sewer rates will be lost through the sale of the systems.

Witness Fernald recommended that the gain on sale assigned to the remaining ratepayers should be flowed through rates by amortizing the gain on sale over a five-year period with the unamortized balance deducted from rate base. Thus, witness Fernald calculated that the amount of gain to be assigned to the remaining sewer service ratepayers should be $1,128,751.

The Public Staff maintained that there is "overwhelming and compelling" evidence in the present case that justifies an exception to the general policy of assigning 100% of the gain to shareholders. Specifically, witness Fernald concluded that the following three circumstances distinguish this case from prior decisions where 100% of the gain on sale was awarded to shareholders:

(1) This is the first time that the adverse impact on rates of remaining customers has been quantified. It was understandable for the Commission to dismiss concern over the adverse impact on remaining customers in Docket Nos. W-354, Subs 148-151 and 155-157, when there was no evidence to indicate if the impact was negligible or substantial.[1] In the present case, the impact in the pending rate case of removing the

[1] While the number of customers on the systems sold by CWS NC in the 1996 transfers considered in Docket Nos. W-354, Subs 148-151 and 155-157 of 900 is similar to the 910 customers on the systems sold in this proceeding, the removal of the systems in the pending rate case for Aqua NC will have an immediate adverse impact on the rates for the remaining sewer customers. In comparison, CWS NC did not have an increase in rates until nine years after the Docket Nos. W-354, Subs 148 et al. proceeding.

systems sold to CMU is significant (an increase in the average sewer bill of $1.96 per month).

(2) The evidence shows that the amount of time it would take for future growth in the Aqua NC customer base to offset the loss of customers to CMU is greater in this case than in prior cases. The number of franchises and contiguous extensions approved by the Commission for Aqua NC, Hydraulics, Ltd., and Heater Utilities, Inc. (Heater) combined has decreased dramatically in recent years in comparison to the late 1990's through mid-2000's, and the level of growth experienced by Aqua NC in recent years has been much slower.[1] The fact that the Company's customer base is now increasing at a slow rate stands in sharp contrast to the high growth period from the late 1990's through mid-2000's.[2] Assigning 100% of the gain on sale to shareholders makes more sense when a high customer growth rate will quickly replace the customers lost in a transfer, thereby bringing back economies of scale to the utility and likely erasing the adverse rate impact in a short period of time. This is the first case where the Commission has been presented evidence that the adverse impact on remaining ratepayers is likely to persist, due to the decline in Aqua NC's customer growth rate. Furthermore, this is the first case where the loss of the systems occurred during a rate case proceeding, and removal of those systems in the rate case has an immediate significant negative impact on the remaining ratepayers.

(3) A large number of customers are subject to being transferred. Approximately 7.06% (910 customers) of the Aqua NC sewer customers would be lost from the uniform rate structure as a result of the transfer. This large reduction in customers factors into the adverse rate impact on remaining customers because the loss of so many customers means a proportionally greater loss of economies of scale. It also increases the amount of time it will take for future growth in the Aqua NC customer base to offset the loss of customers to CMU.

Aqua NC opposed the Public Staff's proposal. Aqua NC is of the opinion that the Commission should continue to allocate 100% of any gain or loss to the shareholders when such systems are transferred. Aqua NC witness Roberts observed that in support of facilitating the "orderly transfer" of systems, in 1994 the Commission established a clear, rational, generic policy of assigning 100% of the gain on sale of systems to those utility shareholders. Aqua NC relied on this clearly articulated policy – as has the regulated industry since at least 1994 – in its business calculations concerning its transfer of assets to CMU.

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[1] On cross-examination, witness Fernald noted that she did not include the number of franchises and contiguous extensions for the years predating the 1994 and 1996 decisions since the filing requirement for contiguous extensions did not start until 1995. (The filing requirement for contiguous extensions was established on February 28, 1995, in Docket No. W-100, Sub 17.)

[2] On cross-examination, witness Fernald explained that the number of customers for Heater on Page 15 of her prefiled direct testimony cannot be compared to the number of customers for Aqua NC on Page 16 of her prefiled direct testimony, since the number of Aqua NC customers on Page 16 includes other companies that are part of Aqua NC, such as Hydraulics, Rayco, Fairways, Brookwood, and LaGrange. Witness Fernald also observed that since Aqua NC acquired Heater in 2004, it has filed for rate cases more frequently.

Witness Roberts asserted that sharing the gain on sale, as proposed by the Public Staff, is inconsistent with the regulatory framework which underlies cost-based ratemaking; is not in the best interests of customers or investors; is particularly unfair to Aqua NC; is not warranted by any facts brought forward here; and should be rejected outright.

Aqua NC argued that the Public Staff has not established any "overwhelming and compelling"[1] evidence for making an exception to the Commission's well-settled policy as to treatment of gain on sale in this proceeding. Aqua NC asserted that the Public Staff has failed to make a convincing case that the policy should be changed and that only assured "future growth" as an offset to the loss of the customers should warrant continuation of the current policy. Aqua NC contends that the Commission's past decisions make it clear that it has recognized that the loss of economies of scale is an inevitable consequence of facilitating the orderly transfer of systems to governmental entities, and that such losses do not justify awarding a portion of the gain on sale to remaining ratepayers.

Witness Roberts explained that Aqua NC sold these systems to CMU for three reasons: (1) the City approached the Company; (2) the City has the ability to parallel and thus strand Aqua NC's investment; and (3) the settled policy of assigning 100% of the gain on sale to shareholders has provided a predictable, settled mechanism for effectuating the Commission's goal of facilitating orderly transfers in exactly this kind of situation.

Witness Roberts testified that if the City of Charlotte had not made this purchase, the City would have been required to spend significant funds to parallel the transferred systems. He observed that the costs to the City and to customers would be high, customers' premises would be disrupted, and Aqua NC's investment would ultimately be stranded. It would be a lose-lose-lose situation. Faced with this circumstance, Aqua NC negotiated in good faith, relying on Commission policy, believing that it was acting completely consistent with well-settled Commission practice.

In addition, Aqua NC maintained that it is not in the business of selling systems. Quite the contrary, Aqua NC's business model is one of purchase, improvement, and long-term ownership and operation. Furthermore, Aqua NC does not believe that the Public Staff's discussion of growth is relevant to this proceeding. Witness Roberts asserted that Aqua America is clearly established throughout its national footprint as a growth company. Aqua NC is interested in acquisitions – not in sales.

Witness Roberts also commented that he understands the Public Staff seeks to find every opportunity to secure an advantage for customers. However, he argued that adopting the Public Staff's position in this case would result in fundamental unfairness to Aqua NC in multiple ways. First, it would breach the regulatory compact; changing a well-established policy after Aqua NC relied on it to its detriment in the negotiations with CMU. Second, it would penalize Aqua NC for effectuating the Commission's clear policy of facilitating an orderly transfer of systems to municipalities. Third, it would reward customers when growth is robust, while singularly

[1] The Commission's stated standard for any change in the generic policy of assigning 100% of any gain on sale to shareholders, enunciated in 1994 in Docket Nos. W-354, Subs 133 and 134, Order of September 7, 1994 at Page 7. See also Docket Nos. W-354, Subs 148-151 and 155-157, Order of August 5, 1996 at Page 12.

penalizing providers when growth slows. Last, it would cause a stark and inequitable imbalance by allocating gain from the CMU sale to ratepayers, yet allocating none of the loss resulting from the Windsor Oaks abandonment to ratepayers.

CMU is of the opinion that the Commission's current policy of allocating 100% of the gain on sale has been quite effective in facilitating the sale of private systems to municipalities like the City of Charlotte. One of the things of interest really is the overall effect of the policy going forward. CMU believes that in matters of annexations certainty in that process is needed. In this age of limited resources to construct needed infrastructure, it is not in the public interest for a city to have to expend limited public funds to construct duplicated facilities, if adequate facilities are already in place. Funds that would be unnecessarily spent duplicating facilities could be otherwise saved, resulting in lower rates to all CMU customers, or spent where needed elsewhere to improve the system or expand service to other customers. Furthermore, witness Shearin maintained that constructing additional lines when lines are already present would harm the associated neighborhoods and the environment as the roads, yards, and driveways would be torn up unnecessarily to lay pipe in constructing the duplicate system(s).

CMU witness Shearin explained that in an annexation situation, the City has two years from the date of the effective date of annexation to get those services in place. Consequently, questions arise and must be answered, such as, can we deliver the service; how much is it going to cost; and can the service be delivered in the required timeframe? With respect to this present acquisition, witness Shearin stated that decisions were made to try to acquire these systems over two and a half years ago; discussions started in early 2009. Apparently, there was not as much certainty as CMU had thought; witness Shearin acknowledged that CMU negotiated with the reliance that this would be no different than the other 22 acquisitions CMU had done. CMU witness Shearin testified, in hindsight, that was obviously a mistake because CMU is now in violation of its annexation statutes at the current time with regard to the CWS NC systems, but not with regard to Aqua NC – the Willows Creek and McCarron Systems have already been transferred to CMU, as Aqua NC did not have an escape clause in its contract. Witness Shearin requested that the Commission also keep the municipal perspective in mind as it looks at the gain on sale policy in this and other similar proceedings.

Witness Shearin stated that it is his understanding that the Commission's long-standing policy is that transfers of water and sewer services to municipalities and sanitary districts should be encouraged. He asserted that there are many good reasons supporting this policy. First, larger public municipal systems provide economies of scale and, consequently, typically lower rates. Second, municipal systems generally have better system reliability, better production facilities, more water storage, a water source from surface water, and can provide better fire protection. Third, municipal systems usually have greater financial stability and strength and access to tax-exempt capital and other advantageous financing arrangements.

Witness Shearin opined that the concern raised by the Public Staff about the effect of the sale of these systems on the remaining ratepayers is largely a function of the imposition of a single uniform rate structure across multiple systems, in which some systems' rates are artificially high and other systems' rates are artificially low. This fact should not be used to discourage the transfer to municipalities of the lower-cost systems that have rates that are higher than they would otherwise be. The higher cost systems with artificially low rates should not have the ability to block the transfer of systems with artificially high rates in the name of helping to maintain artificially low rates for the high-cost customers.

Further, witness Shearin testified that a policy change in which the Commission does not allocate 100% of the gain to the utility would make purchases of private systems by municipalities more expensive. As a long-term broader implication, CMU expects that an increase in the price of privately-owned systems would discourage purchases by municipalities. Moreover, if municipalities were not willing (or able) to pay higher purchase prices, a change in the gain on sale policy would, in effect, prevent the sale of private utilities to municipalities.

CMU advocated that the Commission retain its current policy on the gain on sale treatment, as it believes that a change in this policy will primarily serve to increase the purchase price of these systems as the private utilities look to recover the allocated portion of the gain on sale and will provide a complex negotiation such that some municipalities will no longer consider purchase as a good option and will be forced to construct new, redundant systems.

Furthermore, it is CMU's position that if the Commission were inclined to make any change to what CMU perceives as a long-standing Commission policy, it should be done on a prospective basis only, so as to apply only to future transactions and not to this present proceeding; and that the Commission should provide a "bright line" rule that municipalities could anticipate when going into negotiations to acquire utility infrastructure in the future.

CMU witness Hibbard is of the opinion that the Commission should maintain a policy that will encourage the sale of utility assets to municipalities at a reasonable price; consequently, witness Hibbard stated that the Commission should continue to allocate 100% of the gain on sale of utilities to the utility company's shareholders. Witness Hibbard stated that, for all the reasons set forth in witness Shearin's testimony that the Commission should continue with policy objectives that encourage the transfer of private water and sewer systems to municipalities. Witness Hibbard expressed that it is almost always more efficient and cost-effective for municipalities to acquire existing facilities when adequate rather than to duplicate facilities because (1) municipalities are spared the unnecessary expense of constructing redundant, duplicative systems; (2) utilities are able to sell systems that might otherwise become underutilized; and (3) the private utility's customers can receive the benefits of service from a municipal system (usually at lower rates).

Witness Hibbard testified that during the 2011 session, the General Assembly enacted annexation reform legislation that made substantial changes to the provisions governing the extension of water and sewer services to annexed areas. Such changes became effective on July 1, 2011. Witness Hibbard opined that the statutory amendments increase municipal obligation and cost in providing water and sewer infrastructure and will likely result in a greater need to purchase existing private systems in annexed areas.

Witness Hibbard asserted that the public interest will best be served by retaining a Commission policy that allows for transfers of existing systems to municipalities at a reasonable price so that critical services for water, health and sanitation, and fire protection can be provided to annexed areas in the most efficient and cost-effective manner. Witness Hibbard observed that a policy change to one in which the Commission did not allocate 100% of the gain to the utility would make purchases of private systems by municipalities more expensive and would discourage transfers of systems to municipalities. Further, a change in the Commission's policy, as advocated by the Public Staff, would have the effect of making annexations more difficult and expensive for municipalities, which could result in the undesirable effects of few citizens being able to receive the benefits of municipal services and of cities being unable to annex and serve increasingly urbanized areas along their fringes.

As previously indicated, in prior pertinent and relevant dockets, since September 1994, the Commission has followed a policy, absent overwhelming and compelling evidence to the contrary, of assigning 100% of the gain or loss on the sale of water and/or sewer utility systems to utility company shareholders. In so deciding, it appears that the Commission intended to encourage, to the maximum extent possible, the sale of water and sewer systems to municipalities and other government-owned entities. The Commission found that it should continue to be the policy of the Commission to take such actions as would encourage the larger water and sewer utilities with greater operational and capital resources, including governmental entities, to acquire the smaller, undercapitalized, less efficient systems. The Commission was of the opinion that such a policy served the public interest by promoting efficiencies through economies of scale and generally resulted in more favorable rates and an enhanced quality of service.

The central issue before the Commission in this present proceeding is whether the evidence presented in this proceeding by the Public Staff is "overwhelming and compelling" to the extent that it warrants a partial sharing of the gain on sale with the Company's remaining ratepayers. The instant docket and the currently pending Docket No. W-354, Sub 331, involving CWS NC, present the first efforts by the Public Staff to secure an exception to this long-standing policy since 1996. Based on the facts and circumstances in this immediate proceeding, the Commission is not persuaded that any portion of the gain on sale should be shared with Aqua NC's remaining customers.

While this present Commission is not bound by the Commission's prior determinations, and can revisit this gain on sale policy and determine whether a different approach is warranted in the future in any particular case, they do reflect the considered judgment of the prior Commissions over a number of years. The Commission has carefully reviewed and considered the specific circumstances in this proceeding and cannot find that the record before the Commission warrants abandonment of or an exception to the gain on sale policy adopted by the Commission in 1994 and reaffirmed at least three more times thereafter. The Commission is of the opinion that the Commission's objectives (1) to encourage the larger water and sewer utilities with greater operational and capital resources, including municipalities and other governmental entities, to acquire the smaller, undercapitalized, less efficient systems, (2) to promote the orderly transfer of water and sewer systems from developers and small owners to reputable water and sewer utilities like Aqua NC, municipalities, and other governmental owners, and (3) to encourage to the maximum extent possible such sales, are still very worthy, beneficial, and good public policy goals.

The Public Staff argues that the following three circumstances distinguish this case from prior cases where 100% of the gain on sale was awarded to shareholders. First, this is the first time that the adverse impact on the rates of the remaining Aqua NC customers has been quantified; the impact is significant as it increases the average sewer bill by $1.96 per month. Second, the amount of time it would take for future growth in the Aqua NC customer base to offset the loss of customers to CMU is greater in this case than in prior cases; the level of growth experienced by Aqua NC in recent years has been much slower than during the late 1990's through mid-2000's. Third and last, a large number of customers have been transferred; approximately 7.06% (910 customers) of Aqua NC's sewer customers have been lost from the uniform rate structure as a result of the transfer. In conclusion, the Public Staff asserts that these circumstances are "overwhelming and compelling" evidence in the present case that justifies an exception to the general policy of assigning 100% of the gain to shareholders.

After careful and thorough consideration of the facts and circumstances in this particular proceeding, the Commission finds and concludes that the Public Staff has failed to present "overwhelming and compelling" evidence that sufficiently warrants a ruling by this Commission that an exception to the gain on sale policy is required and necessary. That is, the sharing of the gain on sale proposed by the Public Staff is simply not warranted by the record before us. The Public Staff has not established by "overwhelming and compelling" evidence here that the Commission should revise its policy as to treatment of gain on sale in this particular case.

The Commission's past decisions recognize that the loss of economies of scale is an inevitable consequence of facilitating the orderly transfer of systems to governmental entities, and that such losses do not necessarily justify awarding a portion of the gain on sale to remaining ratepayers. The pertinent facts before us with respect to Aqua NC's transfer of its Willows Creek and McCarron Systems to CMU are not materially different from those with respect to the sales which were the subject of the Commission's prior rulings on treatment of gain on sale in connection with water and sewer transfer applications decided in 1994 and thereafter. It is certainly noteworthy that the matters in Docket Nos. W-354, Subs 148-151 and 155-157 which were the subject of the August 5, 1996 Order Determining Regulatory Treatment[1] discussed hereinabove involved the transfer of approximately 900 customers to CMU by CWS NC; this instant docket involves the transfer of 910 sewer customers to CMU by Aqua NC (as well as 263 water customers).

Although the Commission recognizes that the increase to the monthly sewer bill of approximately 3.00% or $1.96, is not insignificant, the Commission does not believe that such monthly impact constitutes overwhelming and compelling evidence to deviate from the Commission's gain on sale policy under the specific circumstances in this proceeding, as the larger public interest is best served by continuing such policy. The Commission does not consider that any evidence has been presented in this proceeding that meets such a high standard.

Based upon the foregoing, the Commission is of the opinion that Aqua NC should retain for shareholders 100% of the gain on sale of the Willows Creek and McCarron Systems transferred to CMU and 100% of the loss on disposition of Windsor Oaks due to paralleling by the Town of

[1] This Order was admitted into the record in the present proceeding and marked as Aqua Fernald Cross-Examination Exhibit 1.

Cary. In so concluding, the Commission believes that the current policy continues to better serve and promote the public interest and should be followed in this docket, as the evidence and arguments presented by the Public Staff in this case do not represent overwhelming and compelling evidence to warrant an exception in this proceeding. In future cases concerning gain on sale of water and/or sewer systems, the Commission intends to continue with a policy, absent overwhelming and compelling evidence to the contrary, of assigning 100% of the gain on such sale to utility company shareholders as a financial incentive to promote the orderly transfer of water and sewer systems from developers and small owners to reputable water and sewer utilities like Aqua NC, municipalities, and other governmental owners.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The evidence regarding this finding of fact is contained in the Commission's files and in the testimony and exhibits of Public Staff witness Fernald and Company witness Becker. Company witness Becker testified that if the Commission required the Company to share any amount of the gain in this proceeding with ratepayers, it would only be appropriate to allow the Company to share the Windsor Oaks losses with ratepayers as well. He claimed that equity requires a parity of treatment between ratepayers and the shareholder with regard to sharing gains and losses.

Public Staff witness Fernald testified that in general, in cases where a company incurs a loss on the sale or paralleling of a system, and the removal of the system from uniform rates has a material positive impact on the remaining uniform rate ratepayers (e.g., a high cost system that when removed causes a downward impact on uniform rates), it would be reasonable to assign a portion of the loss to ratepayers under uniform rates, but only to the extent that the portion of the loss assigned to those ratepayers is offset by the positive impact of the removal of the system and does not cause a rate increase. Witness Fernald explained that this would depend on a review of the reasons for the loss, including whether the loss was reasonable and prudently incurred. Witness Fernald testified that this is not the case for Windsor Oaks, since the loss of the Windsor Oaks system will not have a positive impact on the remaining ratepayers. Witness Fernald observed that the Windsor Oaks sewer system is not in uniform rates, so there is no basis for sharing a gain or loss with remaining ratepayers. Further, witness Fernald maintained that for the water system, since there is a negative impact on the remaining ratepayers, they should not also have to bear a portion of the loss. (The loss in terms of net book value of the Windsor Oaks water and sewer systems is $225,486, which consists of $67,468 for the water operations and $158,018 for the sewer operations.)

Based on the positions advocated by the Public Staff and the Company, respectively, and although their recommendations were based upon differing opinions and analysis, neither recommended that the remaining ratepayers bear any portion of the loss in this situation. Based upon the foregoing, the Commission finds and concludes that the loss on abandonment of the Windsor Oaks systems should be assigned 100% to Aqua NC's shareholders.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The evidence regarding this finding of fact is contained in the June 30, 2011 Stipulation, the testimony and exhibits of Public Staff witness Fernald and Company witness Becker, and the September 13, 2011 Notice of Decision and Order, in Docket No. W-218, Sub 319. In that Notice of Decision and Order, the Commission approved rates on a provisional basis subject to adjustment to reflect the Commission's rulings in this proceeding concerning (a) the treatment of any gain on sale, (b) the treatment of the loss on disposition of Windsor Oaks, (c) the revenues, expenses, and rate base associated with the Windsor Oaks system and the systems being sold to the City of Charlotte, and (d) any other rulings by the Commission in this proceeding. The Commission's Order also noted that Aqua NC will be required to adjust its rates accordingly and refund overcollections, if any, with interest, as determined by the Commission in this instant proceeding.

Based upon the testimony and exhibits of Public Staff witness Fernald and Company witness Becker and the conclusions reached by the Commission elsewhere in this Order, the rate base, revenues, and expenses set forth in the Commission's Docket No. W-218, Sub 319, Order should be adjusted as follows:

(1) The net book value removed from rate base for the Willows Creek and McCarron Systems sold to CMU should be revised to reflect the amounts agreed to by Aqua NC and the Public Staff in this proceeding, as shown on Fernald Exhibit I, Schedules 2(a) and 2(b) and Becker Exhibit I, Schedules 2(a) and 2(b). The final amounts for the net book value of the water and sewer systems sold to CMU are as follows:

	Aqua NC Water	Aqua NC Sewer
Plant in service	$ 821,951	$ 3,101,845
Accumulated depreciation	(282,791)	(950,939)
Contributions in aid of construction	(399,450)	(2,618,477)
Accum. amort. of CIAC	181,396	986,467
Purchase acquisition adjustment	84,991	41,167
Accum. amort. of PAA	(19,180)	(14,557)
Total to be removed	$ 386,917	$ 545,506

(2) The net book value removed from rate base for the Windsor Oaks system should be revised to reflect the amounts agreed to by Aqua NC and the Public Staff in this proceeding, as shown on Becker Exhibit II, Schedules 2(a) and 2(b). Public Staff witness Fernald testified that she agreed with the amounts presented by Aqua NC. The final amounts for the net book value of the Windsor Oaks system are as follows:

	Aqua NC Water	Aqua NC Sewer
Plant in service	$ 270,731	$ 498,410
Accumulated depreciation	(195,880)	(229,527)
Contributions in aid of construction	(89,488)	0
Accum. amort. of CIAC	82,105	0
Purchase acquisition adjustment	0	(233,400)
Accum. amort. of PAA	0	122,535
Total to be removed	$ 67,468	$ 158,018

(3) Rate base should be increased by $37,408 for water operations and $129,441 for sewer operations to remove the credit balance of accumulated deferred income taxes associated with the Willows Creek and McCarron Systems sold to CMU. These amounts were agreed to by Aqua NC and the Public Staff in this proceeding, as shown on Fernald Exhibit I, Schedules 2(a) and 2(b) and Becker Exhibit I, Schedules 2(a) and 2(b).

(4) Rate base should be increased by $12,942 for water operations and $12,942 for sewer operations to remove the credit balance of accumulated deferred income taxes associated with the Windsor Oaks systems. These amounts are shown on Becker Exhibit II, Schedules 2(a) and 2(b), and were agreed to by Public Staff witness Fernald in her rebuttal testimony.

As suggested by the Public Staff in its Proposed Order, it will benefit the Commission if the Public Staff and the Company prepare and file, jointly if possible, revised schedules and rates reflecting the Commission's rulings in this proceeding and a proposal of how rate changes should be implemented, if any. The Commission would like this information to be filed in Docket No. W-218, Sub 319, within 30 days of the effective date of this Order. The filing should reflect the amounts determined to be reasonable by this Commission in its September 13, 2011, Notice of Decision and Order, adjusted for the revisions detailed above.

IT IS, THEREFORE, ORDERED as follows:

1. That 100% of the gain on sale of the Willows Creek and McCarron water and sewer public utility systems owned by Aqua NC, which serve the Timberlands, Satterwythe Place/Alderwood, Brantley Oaks, Willows Creek, Stone Mountain, Reedy Creek Plantation, and McCarron subdivisions, shall be assigned to Aqua NC's shareholders.

2. That 100% of the loss on the abandonment of Aqua NC's Windsor Oaks water and sewer systems shall be assigned to Aqua NC's shareholders.

3. That the Public Staff and Aqua NC shall prepare and file, jointly if possible, revised schedules and rates reflecting the Commission's rulings in this proceeding and a proposal of how rate changes should be implemented, if any. These schedules and rates should be filed in Docket No. W-218, Sub 319, within 30 days of the effective date of this Order, and should reflect the amounts determined to be reasonable by this Commission in its September 13, 2011, Notice of Decision and Order, adjusted for the revisions detailed above.

4. That Aqua NC shall file reports with the Commission and the Public Staff concerning the calculations of the gain and loss including the detailed work papers supporting those calculations.

5. That Aqua NC shall file journal entries related to the sale of these systems, including the removal of the plant and associated accounts from Aqua NC's books and records in a manner consistent with the provisions of this Order.

ISSUED BY ORDER OF THE COMMISSION
This the 23rd day of December, 2011.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Commissioner ToNola D. Brown-Bland concurs.

Chairman Edward S. Finley, Jr. and Commissioner William T. Culpepper, III did not participate in this decision.

bk122311.01

DOCKET NOS. W-218, SUBS 325, 327, and 319

COMMISSIONER TONOLA D. BROWN-BLAND CONCURRING: I concur in the result reached by the majority because assigning 100% of the gain on sale to the shareholders of Aqua NC promotes the Commission's stated policy of encouraging, to the maximum extent possible, the sale of water and sewer systems to municipalities and other government-owned entities in support of the public interest. I also believe the result of today's decision is in the public interest because it supports promotion of the acquisition of smaller, troubled systems by larger privately owned water and sewer utilities.

\s\ ToNola D. Brown-Bland
Commissioner ToNola D. Brown-Bland

APPENDIX A

Overview of Selected Numerical Data
(Docket No. W-218, Sub 325)

Line No.	Aqua North Carolina, Inc.	Water	Sewer	Total
1	Purchase Price – Sale to CMU			$4,167,500
2	Less: Net Book Value	$386,917	$545,506	932,423
3	CWIP			22,276
4	Selling Costs and Legal Fees			50,354
5	Gain on Sale (W/S allocation per Public Staff)	$632,489	$2,529,958	$3,162,447
6	Number of Customers Transferred	263	910	1,173
7	Total Customers (excludes Fairways & Brookwood)	54,090	12,887	66,977
8	Percentage of Customers Transferred	0.49%	7.06%	1.75%
9	Annual Revenue Requirement Impact (per Public Staff)	$6,204	$281,059	
10	Impact per Month per Bill (per Public Staff) Approximate Percentage Increase	$0.01 NA	$1.96 3.00%	
11	Average Monthly Bill Under Provisional Rates (water: 4,925 gallons; sewer: flat)	$41.89	$64.95	
12	Public Staff Recommended Sharing of Gain:			
13	Amount of Gain to Ratepayers	$0	$1,128,751	$1,128,751
14	Percentage of Gain to Ratepayers	0%	44.6%	35.7%
15	Amount of Gain to Company	$632,489	$1,401,207	$2,033,696
16	Percentage of Gain to Company	100%	55.4%	64.3%
17	Public Staff Recommended Amortiz. Period		5 years	

Notes:

1. Primary source of information is the Public Staff's Proposed Order filed on October 11, 2011, which includes Fernald Exhibit I Final consisting of Schedules 1-4.
2. Aqua NC's present water rates are $17.12 base charge and $5.03 per 1,000 gallons usage. Per September 13, 2011 Notice of Decision and Order in Sub 319 proceeding.

DOCKET NO. W-354, SUB 331

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Carolina Water Service, Inc. of North Carolina, 2335 Sanders Road, Northbrook, Illinois 60062, for Authority to Transfer the Water and Sewer Utility Systems Serving Cabarrus Woods, Victoria Park, Bradford Park, Brookstead/Cambridge, Brookstead Meadows, Canford Commons, Reedy Creek Run/Brookstead, Turtle Rock, Avensong, Stewart's Crossing, Brawley Farms, Preserve at Kinsley Lake, Lamplighter Village East, Brookdale, Steeplechase, Britley, Windsor Chase, Williams Crossing, Williams Station, Julian Meadows, South Windsor, Southwoods, Brandywine, and Forest Ridge in Cabarrus and Mecklenburg Counties, North Carolina to the City of Charlotte, which is exempt from Commission Regulation	)	ORDER DETERMINING REGULATORY TREATMENT OF GAIN ON SALE

HEARD: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina on Tuesday, August 23, 2011, at 9:00 a.m.

BEFORE: Commissioner Bryan E. Beatty, Presiding; Commissioner Lorinzo L. Joyner; Commissioner William T. Culpepper, III; Commissioner Susan W. Rabon; Commissioner ToNola D. Brown-Bland; and Commissioner Lucy T. Allen

APPEARANCES:

For Carolina Water Service, Inc. of North Carolina:

Christopher J. Ayers, Poyner Spruill LLP, Post Office Box 1801, Raleigh, North Carolina 27602

For Charlotte-Mecklenburg Utilities:

M. Gray Styers, Jr. and Karen Kemerait, Styers & Kemerait, PLLC, 1101 Haynes Street, Suite 101, Raleigh, North Carolina 27604

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

WATER AND SEWER – SALE/TRANSFER

BY THE COMMISSION: On March 3, 2011, Carolina Water Service, Inc. of North Carolina (CWS NC or Company) filed an application with the Commission for authority to transfer its franchise for providing water and sewer utility service in the following subdivisions: Cabarrus Woods, Victoria Park, Bradford Park, Brookstead/Cambridge, Brookstead Meadows, Canford Commons, Reedy Creek Run/Brookstead, Turtle Rock, Avensong, Stewart's Crossing, Brawley Farms, Preserve at Kinsley Lake, Lamplighter Village East, Brookdale, Steeplechase, Britley, Windsor Chase, Williams Crossing, Williams Station, Julian Meadows, South Windsor, Southwoods, Brandywine, and Forest Ridge (collectively referred to as the Cabarrus Woods Systems) in Mecklenburg and Cabarrus Counties, North Carolina, to Charlotte-Mecklenburg Utilities (CMU), a department of the City of Charlotte (City), North Carolina, which is exempt from Commission regulation.

On April 7, 2011, CWS NC filed a revised Attachment 1 to its application in order to correctly state the number of customers in the "Cabarrus Woods/Steeplechase Subdivision."

On April 8, 2011, the Commission issued an Order Requiring Customer Notice, specifying that the matter may be determined without public hearing if no significant protests were received subsequent to customer notice.

On April 21, 2011, CWS NC filed a motion to revise customer notice and requested an extension of time within which to provide such revised notice. In support of its motion CWS NC stated that the sale agreement between CWS NC and CMU provides that CWS NC will transfer all utility property, equipment, and customers to CMU on the date of transfer. Upon completion of the transfer of customers from CWS NC to CMU, CMU intends to immediately transfer customers located in Cabarrus County to the Town of Harrisburg. Customers in the following subdivisions will be transferred by CMU to the Town of Harrisburg: Bradford Park, Victoria Park, Cabarrus Woods, Brookdale, Britley, and a portion of Steeplechase. CWS NC proposed to revise the customer notice included in the Commission's April 8, 2011 Order to include the applicable utility rates for the Town of Harrisburg.

On May 3, 2011, the Commission issued an Order Revising Customer Notice and Granting Extension of Time. Such notice reflected that CMU's and the Town of Harrisburg's rates would decrease the average monthly water and sewer bill from $80.70 to $41.82 and from $80.70 to $60.42, respectively, based upon 4,750 gallons for water and sewer. In addition, existing CWS NC customers that are transferred would not be required to pay a connection fee.

On May 17, 2011, CMU filed a petition to intervene. On May 31, 2011, the Commission issued an Order Granting Intervention.

On June 1, 2011, CWS NC filed its Certificate of Service indicating that notice was provided as required by the Commission's May 3, 2011 Order. No customer protests were received.

On June 27, 2011, the Public Staff - North Carolina Utilities Commission (the Public Staff) presented this matter at the Regular Commission Staff Conference. The Public Staff stated that it was not opposed to transfer of the Cabarrus Woods Systems to CMU, but wanted to introduce evidence to the Commission of an adverse cost impact on the customers remaining with CWS NC. The Public Staff recommended that the Commission set for hearing the matter of how, if at all, the remaining ratepayers should be protected from any adverse cost impact. Christopher J. Ayers, attorney for CWS NC, appeared on behalf of the Company. CWS NC indicated that it preferred that approval of the transfer be postponed until the issue raised by the Public Staff was resolved.

On June 29, 2011, the Commission issued an Order Postponing Transfer and Scheduling Hearing which set the matter for hearing on August 23, 2011, in Raleigh, North Carolina; established filing dates for testimony and rebuttal testimony; and postponed the transfer until such time as CWS NC withdrew its transfer application or files a motion for approval of the application.

On July 22, 2011, the Public Staff filed the testimony and exhibit of Katherine A. Fernald, Supervisor, Water Section, Accounting Division. On August 3, 2011, CMU filed the testimony and exhibits of Barry D. Shearin, Chief Engineer for CMU, and Kimberly S. Hibbard, General Counsel of the North Carolina League of Municipalities. Also on August 3, 2011, CWS NC filed the testimony and exhibit of Steven M. Lubertozzi, Executive Director of Regulatory Accounting and Affairs at Utilities, Inc., and the testimony of Hugh A. Gower, a consultant.

On August 11, 2011, the Public Staff filed a motion requesting that the Commission compel CWS NC to respond to its Fifth and Eighth Data Requests. On August 12, 2011, CWS NC filed its response to the Public Staff's motion to compel.

On August 15, 2011, the Public Staff filed the rebuttal testimony and exhibit of witness Fernald. On August 16, 2011, the Commission granted the Public Staff's motion to compel with regard to the Public Staff's Fifth and Eighth Data Requests to CWS NC.

The matter was heard as scheduled on August 23, 2011. There were no public witnesses. The expert witnesses who had filed testimony presented their testimonies and exhibits to the Commission.

On August 30, 2011, the Public Staff filed Fernald Exhibit I – Revised 8/30/11 which reflected the correction noted in witness Fernald's testimony at the hearing; namely, the removal of the Company's Nags Head sewer customers who are not in the uniform rates from the Company's count of its customers under uniform rates.

On September 22, 2011, CWS NC and CMU filed a joint motion for extension of time to file proposed orders and/or briefs. The movants stated that the Public Staff did not object to such request. On September 23, 2011, the Commission issued an Order Granting Extension of Time to File Briefs and/or Proposed Orders.

On October 11, 2011, CWS NC filed its Brief and Proposed Order; the Public Staff filed its Proposed Order; and CMU filed its Brief, a Proposed Order, and an Alternative Proposed Order.

Based upon the foregoing, the evidence presented at the hearing, and the entire record in this matter, the Commission makes the following

FINDINGS OF FACT

1. CWS NC is a corporation duly organized under the law of and is authorized to do business in the State of North Carolina. CWS NC is a franchised public utility providing water and/or sewer utility service to customers in North Carolina.

2. Effective June 30, 2009, the City of Charlotte, a municipal corporation, annexed certain areas in the eastern part of Mecklenburg County described as the Hood Road North and Hood Road South areas. At that time, CWS NC was providing water and sewer public utility service in some parts of the Hood Road South annexed area through its Brookstead/Cambridge, Brookstead Meadows, Canford Commons, Reedy Creek Run/Brookstead, Turtle Rock, Avensong, Stewart's Crossing, Brawley Farms, and the Preserve at Kinsley Lake subdivisions.[1]

3. The City of Charlotte's CMU Department approached CWS NC in early 2009, prior to the Hood Road North and Hood Road South annexations, to discuss the possible sale by CWS NC to CMU of certain of the Company's water and sewer systems in order for CMU to serve existing CWS NC customers in the annexed areas. CMU sought to acquire these systems from CWS NC in order to avoid the expense and disruption of constructing new, redundant lines and duplicating the existing facilities in the annexed areas. The negotiations between CWS NC and CMU resulted in an agreement whereby CMU would purchase many CWS NC subdivisions that were not necessarily needed to comply with the annexation or extension policies in order to accommodate CWS NC's business plan.

4. Pursuant to North Carolina law and the City of Charlotte's utilities facilities extension policy, the City is required to extend water and sewer facilities into the annexed areas to allow annexed property owners to obtain water and sewer services from the City within two years of the effective date of an annexation.

5. CMU and CWS NC have reached a tentative agreement whereby CMU will pay $25.7 million for the water and sewer systems of CWS NC in the subdivisions collectively referred to as the Cabarrus Woods Systems. Such agreement contains an "escape clause" that allows CWS NC to terminate the agreement if the Commission does not approve the assignment of the entire gain on sale of the systems to CWS NC's shareholders.[2] CWS NC's estimated net investment in the Cabarrus Woods Systems is $6.5 million, resulting in an estimated gain on sale of $19.2 million.

[1] Based upon a review of the maps included in the Company's application, the testimony of CWS NC witness Lubertozzi, and Exhibit E attached to the direct testimony of CMU witness Shearin, the Commission has identified that these nine CWS NC subdivisions are included in the Hood Road South annexed area.

[2] CWS NC is wholly owned by Utilities, Inc., which is a company headquartered in Northbrook, Illinois. Utilities, Inc., owns water and sewer businesses in 15 states. References to CWS NC's shareholders mean Utilities, Inc.

6. The transfer of the Cabarrus Woods Systems from CWS NC to CMU would be in the best interest of the customers on those systems and the City. There are approximately 2,849 water customers and 3,359 sewer customers on the Cabarrus Woods Systems representing a total of approximately 6,208 customers to be transferred. Such water and sewer customers represent 13.2% and 24.7%, respectively, of CWS NC's total number of uniform rate customers.

7. The issue of treatment of gain on sale for water and sewer utility companies is a matter that has been previously addressed by the Commission in a number of prior dockets. In particular, in Docket Nos. W-354, Subs 133 and 134, in the September 7, 1994 Order Determining Regulatory Treatment Of Gain On Sale Of Facilities, the Commission concluded that "in future proceedings, the Commission will follow a policy, absent overwhelming and compelling evidence to the contrary, of assigning 100% of the gain or loss on the sale of water and/or sewer utility systems to utility company shareholders." Since 1994, the Commission has applied this policy of awarding 100% of the gain or loss on sale of water and sewer systems to the utility company's shareholders. Although this allocation has been challenged in only a few cases during this 17-year period, the Commission has not found sufficient evidence in the past proceedings to merit a deviation from the presumptive allocation until this present proceeding involving CWS NC.

8. The transfer of the Cabarrus Woods Systems will have a significant adverse impact on the rates of the remaining customers in the CWS NC uniform rate structure after the transfer if no regulatory action is taken to protect those customers. The estimated adverse impact on such remaining CWS NC customers is an increase in the average water bill of $2.37 per month and in the average sewer bill of $2.41 per month. Such estimated increases reflect a monthly increase of 5.8% and 6.0% in the average water and sewer bill, respectively.

9. Due to the significant adverse effects that will be caused by the transfer of a large number of customers from CWS NC's uniform rate structure, that is 6,208 customers, there is overwhelming and compelling evidence to justify an exception to the Commission's current policy of assigning 100% of the gain on sale of water and/or sewer utility systems to utility company shareholders in this proceeding.

10. It is reasonable and appropriate to assign an estimated $3.36 million or 17.5% of the gain on sale to the remaining ratepayers in the CWS NC uniform rate structure after the transfer and $15.83 million or 82.5% to shareholders under the proposed transfer application. The apportionment of 17.5% of the gain on sale to the remaining CWS NC ratepayers is necessary in order to offset the extraordinary and exceptional negative impact to such customers.

11. It is inappropriate to characterize a sharing of the gain on sale with remaining ratepayers as forcing CWS NC's shareholders or CMU to perpetuate a subsidy to the remaining ratepayers.

12. Assigning a portion of the gain on sale to the remaining ratepayers in the CWS NC uniform rate structure is not inconsistent with cost-based ratemaking principles or the National Association of Regulatory Utility Commissioners' Uniform System of

Accounts (USOA). The Commission has both the responsibility and the authority to prescribe the regulatory accounting treatment it considers appropriate for gain on sale.

13. The uncertain possibility of an increase in sales price for the Cabarrus Woods Systems is not sufficient reason to leave the remaining CWS NC ratepayers in the CWS NC uniform rate structure with an adverse cost impact.

14. Under the circumstances of this case, CWS NC has a considerable incentive, the possibility of an estimated $15.83 million gain for shareholders, to close the transfer agreement with CMU even after sharing with the remaining CWS NC ratepayers in the CWS NC uniform rate structure a portion of the gain sufficient to prevent such ratepayers from being subject to increased rates as a result of the transfer.

15. It is just and reasonable under the circumstances of this case for an estimated $3.36 million of the gain on sale to be amortized to ratepayers over a five-year period beginning with the date CWS NC receives payment from CMU. The unamortized balance should be included in rate base as a deduction.

16. The Commission's decision herein is strictly based upon the facts and circumstances presented in this proceeding and does not represent a change in the Commission's long-standing policy of assigning 100% of the gain or loss on the sale of water and/or sewer utility systems to utility company shareholders, absent overwhelming and compelling evidence to the contrary.

17. CWS NC has not maintained system-specific data adequately on its books. Such data is needed to determine the actual amount of the gain on sale to be assigned to ratepayers and the amount of plant investment to be transferred which should be removed from rate base. CWS NC should file with the Commission: (a) system-specific data, including a corrected list of plant, contributions in aid of construction (CIAC) and purchase acquisition adjustment (PAA) additions and retirements by year for each of the systems sold to CMU; (b) a final calculation of the net book value and the annual level of depreciation and amortization expense for each of the systems sold to CMU; and (c) an updated calculation of the gain on sale assigned to the remaining ratepayers.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

The evidence supporting this finding of fact is contained in the Company's filings in this docket and in the Commission's records. This finding is primarily jurisdictional and informational and is uncontested.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 2 THROUGH 4

The evidence supporting these findings of fact is found in the Company's application and in the testimony of CWS NC witness Lubertozzi and CMU witness Shearin. These are principally factual matters that are generally uncontested and noncontroversial.

Witness Lubertozzi testified that the following subdivisions in Mecklenburg and Cabarrus Counties, North Carolina are the subject of the CMU transfer: Cabarrus Woods, Victoria Park, Bradford Park, Brookstead/Cambridge, Brookstead Meadows, Canford Commons, Reedy Creek Run/Brookstead, Turtle Rock, Avensong, Stewart's Crossing, Brawley Farms, Preserve at Kinsley Lake, Lamplighter Village East, Brookdale, Steeplechase, Britley, Windsor Chase, Williams Crossing, Williams Station, Julian Meadows, South Windsor, Southwoods, Brandywine, and Forest Ridge, which are collectively referred to as the Cabarrus Woods Systems. Witness Lubertozzi stated that once the transfer is completed, it is planned that the following systems in Cabarrus County would be further transferred to the Town of Harrisburg: Bradford Park, Victoria Park, Cabarrus Woods, Brookdale, Britley, and a portion of Steeplechase. Further, witness Lubertozzi testified that CWS NC decided to sell its Cabarrus Woods Systems to CMU following the City of Charlotte's annexation of much of the service area into Charlotte's city limits. Witness Lubertozzi stated that some of the service area affected by the sale was included because of Mecklenburg County's main extension policy. CWS NC's agreement with the City's request to transfer these systems to CMU, allowed CWS NC to avoid the risk that CMU would parallel the subdivisions in the annexed areas.

CMU witness Shearin testified that effective June 30, 2009, the City of Charlotte annexed certain areas in the eastern part of Mecklenburg County, described as the Hood Road North and Hood Road South areas, and sought to purchase certain of CWS NC's water and sewer utility systems in order to serve the existing CWS NC customers in the Hood Road South annexed area so that CMU could avoid the expense and disruption of constructing new, redundant lines and duplicating the existing facilities in these annexed areas. However, witness Shearin testified that CMU had initially approached CWS NC about purchasing only those subdivisions that were included in the Hood Road South annexed area. Witness Shearin explained that of the 24 subdivisions that are subject to being transferred, that either "10 or 11" of those subdivisions are in the annexed area and the remaining "13 or 14" subdivisions were included in the purchase agreement to satisfy CWS NC's business plan and were not necessary to comply with the annexation or line extension policies. Witness Shearin stated that CMU is obligated to provide water and sewer services to residents in the annexed areas in accordance with North Carolina law; and that this must be done within two years of the effective date of the annexation.

Witness Shearin did not specifically name the "10 or 11" subdivisions that are included in the Hood Road South annexed area. However, the Commission has endeavored to identify the names of such "10 or 11" systems to better understand the proposed transaction. Based upon a review of the maps included in the Company's application, the testimony of CWS NC witness Lubertozzi, and Exhibit E attached to the direct testimony of CMU witness Shearin, the Commission has identified the following nine subdivisions included in the Hood Road South annexed area: Brookstead/Cambridge, Brookstead Meadows, Canford Commons, Reedy Creek Run/Brookstead, Turtle Rock, Avensong, Stewart's Crossing, Brawley Farms, and the Preserve at Kinsley Lake subdivisions.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence regarding this finding of fact is contained in the Company's application; the testimony and exhibits of Public Staff witness Fernald, Company witness Lubertozzi, and CMU witnesses Shearin and Hibbard, and is uncontested.

The agreement for sale of the Cabarrus Woods Systems, with an effective date of March 1, 2011, was attached to the application for transfer. Such agreement is tentative because of an "escape clause" whereby CWS NC may terminate the agreement if the Commission does not allow CWS NC to retain 100% of the gain on sale for its shareholders. The agreement provides for the City to purchase the Cabarrus Woods Systems for $25,700,000.

Public Staff witness Fernald testified that the total purchase price under the contract is $25,700,000, and, based on information provided by the Company, CWS NC's net investment in the systems is $6,512,691, resulting in an estimated gain on sale of $19,187,309. Witness Fernald explained that this was an estimated amount as she could not determine the accuracy of the system-specific net investment amounts provided by the Company until CWS NC provides more complete system-specific data. Witness Fernald maintained that while the exact amount of the net investment for the systems being sold and the resulting gain on sale are not known, at this time, the Public Staff believes that the impact of the transfer on the remaining ratepayers and the appropriate regulatory treatment can still be resolved by the Commission based on the preliminary amounts provided by the Company, provided the Company is required to file a final calculation of the system-specific net book value, annual level of depreciation, and annual level of CIAC and PAA amortization expense for the Cabarrus Woods Systems. Company witness Lubertozzi did not contest the Public Staff's estimated amount of $19.2 million for the gain on sale.

Accordingly, the Commission finds that the estimated gain on sale for the Cabarrus Woods Systems is $19.2 million under the current contract between CWS NC and CMU. The Commission is of the opinion that it is reasonable to use the $19.2 million estimate for purposes of preliminarily determining the regulatory treatment of the gain on sale, subject to review based upon the subsequent filing of system-specific data and an updated calculation of the gain on sale assigned to the remaining ratepayers as addressed below.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence regarding this finding of fact is contained in the testimony and exhibits of Public Staff witness Fernald, Company witness Lubertozzi, and CMU witnesses Shearin and Hibbard, and is uncontested. There are four groups who will be affected by the transfer of these systems: (1) the City; (2) CWS NC's shareholders; (3) the ratepayers (customers) on the Cabarrus Woods Systems; and (4) the remaining ratepayers in the CWS NC uniform rate structure after the transfer.

Public Staff witness Fernald testified that the customers on the Cabarrus Woods Systems will benefit from a reduction in their rates due to the transfer; consequently, the Public Staff believes that the transfer of the systems is in the interest of those customers. According to information contained in the customer notice included in the Commission's May 3, 2011 Order, CMU's and the Town of Harrisburg's rates would decrease the average monthly water and sewer bill from $80.70 to $41.82 and from $80.70 to $60.42, respectively, based upon 4,750 gallons for water and sewer. In addition, existing CWS NC customers that are transferred would not be required to pay a connection fee.

The Company and CMU generally agreed that the proposed transfer was in the best interest of the customers served by the Cabarrus Woods Systems due to inherent advantages that municipal systems normally have over privately owned systems. Such advantages include, but are not limited to, (1) typically municipal systems have lower rates due to the economies of scale provided by such larger systems; (2) municipal systems generally have better system reliability, better production facilities, more water storage, a water source from surface water, and better fire protection; and (3) municipal systems usually have greater financial stability and strength and access to tax-exempt capital and other advantageous financing arrangements.

Consistent with the position of all parties, the Commission finds and concludes that the transfer of the Cabarrus Woods Systems to CMU would be in the best interest of the customers on those systems. In addition, the testimony of CMU witnesses supports the finding that the proposed transfer will be in the best interest of the City in terms of avoiding inefficient duplication of facilities and avoiding disruption due to construction. The interests of the remaining customers in the CWS NC uniform rate structure after the transfer and the interests of CWS NC's shareholders are discussed below.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence regarding this finding of fact is contained in the Commission's files and decisions in the dockets referenced hereinafter, which are pertinent and relevant to the issue presented in this present proceeding, and in the testimony of Public Staff witness Fernald and CWS NC witness Lubertozzi. The Commission is of the opinion that a review of the history of the evolution of the Commission's policy analyses and decisions as to treatment of gain on sale of water or sewer utility systems is beneficial and insightful to the instant analysis and the rulings being determined in the present proceeding. Accordingly, the following overview is provided.

In 1990, CWS NC was confronted by efforts of three municipal or governmental entities to acquire three of its systems. The City of Charlotte, through CMU, sought to acquire CWS NC's Beatties Ford system in Mecklenburg County. The Eastern Wayne Sanitary District sought to acquire CWS NC's Genoa system in Wayne County, and the Town of New Bern sought to acquire CWS NC's Riverbend system in Craven County. (Order Determining Regulatory Treatment of Gain on Sale of Facilities, October 16, 1990, Docket Nos. W-354, Subs 82, 86, 87, and 88.) CWS NC entered into tentative contracts to sell the three systems and requested that the Commission rule on the issue of whether the Company's stockholder should be permitted to retain 100% of the gain on sale.

In Docket Nos. W-354, Subs 82, 86, 87, and 88, which involved CWS NC's sale of systems to CMU, the Public Staff and the Attorney General advocated giving 100% of the gain on sale to the Company's ratepayers. After an evidentiary hearing, the Commission held that the gain should be split 50/50 between the Company's ratepayers and its shareholders. The Commission reasoned that both the shareholders and the ratepayers bore part of the risk in maintaining the systems and both should share equally in the profits upon disposition through sale.

As CWS NC's contracts for the sale of those three systems were conditioned on the Commission's ruling, each of the three contracts was renegotiated in light of the Commission's ruling. CWS NC sought to obtain a higher price for the systems since the Commission's ruling denied the Company half of the profit for which it had initially bargained. CMU paid an increased price for the Beatties Ford system. While the Eastern Wayne Sanitary District determined that it would rather parallel the Genoa system than pay more than what it had initially bargained to pay, it ultimately paid less than the tentative contract price. New Bern was unwilling to pay an increased price, and the sale of the Riverbend system to New Bern did not take place.

In 1992, in the aftermath of the CWS NC gain on sale cases, Heater Utilities, Inc. (Heater) sold the system in the Pinewood Subdivision to the City of Goldsboro and sought to discontinue service to the Country Acres Subdivision in Wayne County. In Docket Nos. W-274, Subs 71 and 72, Heater asked the Commission to permit it to retain 100% of the gain on sale. An Order Determining Regulatory Treatment of Gain on Sale and Loss on Abandonment of Facilities was issued May 21, 1993. The Commission affirmed the rationale it had relied upon in the 1990 CWS NC cases and ruled that the gain should be shared 50/50 between shareholders and ratepayers. While the Commission ruled that the evidence was not sufficiently different to warrant a different result, four members of the Commission filed concurring or dissenting opinions wherein they expressed concerns that past decisions may have discouraged or certainly not encouraged the sale of systems to municipal operators, to the detriment of the public interest.

In 1993 and 1994, CWS NC again faced requests that it sell systems in Mecklenburg County to CMU. In light of the differences of opinion expressed in the Heater Docket Nos. W-274, Subs 71 and 72, CWS NC again requested that the Commission address the gain on sale issue as a result of transfer applications filed in Docket Nos. W-354, Subs 133 and 134. In that proceeding, CWS NC argued that regulatory treatment denying the utility's shareholders the opportunity to retain the gain, including gain-splitting, discouraged sales of systems to municipal or governmental operators. The Public Staff argued that the Commission should adhere to the ruling from the earlier cases and split the gain equally between the Company's shareholders and its remaining ratepayers.

In Docket Nos. W-354, Subs 133 and 134, the Commission held, in the September 7, 1994 Order Determining Regulatory Treatment, that in future cases, where a question was raised about the treatment of a gain resulting from the sale of water or sewer utility assets, the Commission would allocate 100% of the gain on the sale to shareholders unless there was overwhelming and compelling evidence that the total amount of the gain should not be allocated to the shareholders.

In that Order the Commission stated the following:

> The gain splitting policy [that was in effect prior to the Commission's decision in this docket] must also be examined within the context of the impact of the policy on the process through which the ownership of private water and sewer systems customarily change hands. Under the most common pattern, the private system is installed by a developer with no interest or ability to operate and maintain the system over the long term. Companies like CWS, with capital and operational expertise and with the long-term desire to operate the systems, acquire them from developers or small operators. Over time, as municipal development and expansion take place, opportunities often arise through which a municipality or

governmental system takes over from the private utility operator. At each step, the customer benefits from the transfer of ownership. Water quality may improve, and the potential exists for lower rates. That being the case, the Commission should not impose economic barriers to the orderly transfer of water systems to municipal entities, as was inadvertently done in the Riverbend situation.

If economic incentives are removed so that this succession of ownership becomes inadvisable, customers are denied those benefits. If companies like CWS are prevented from retaining the gain on sale in North Carolina, a substantial incentive is removed for those companies to buy systems from developers or small, undercapitalized operators in the first instance. Likewise, a substantial incentive is removed to negotiate to sell systems to municipal or governmental entities. At a minimum, the sale price is artificially increased above the fair market based price to adjust for the payment of part of the gain to customers. The result is harm to consumers because the natural progression of transfer of ownership to the most efficient provider is disrupted. These harmful consequences are clearly not in the public interest.

. . .

[T]he Commission rejects the Public Staff's reliance upon the prior [Carolina Water Service] and Heater [Utilities] decisions for purposes of these consolidated dockets and hereby **announces that in future proceedings, the Commission will follow a policy, absent overwhelming and compelling evidence to the contrary, of assigning 100 percent of the gain or loss of the sale of water and/or sewer utility systems to utility company shareholders.** In so deciding, the Commission intends to encourage, to the maximum extent possible, the sale of water and sewer systems to municipalities and other government-owned entities. It is, and shall continue to be, the policy of this Commission to take such actions as will encourage the larger water and sewer utilities with greater operational and capital resources, including governmental entities, to acquire the smaller, under-capitalized, less efficient systems. Such policy serves the public interest by promoting efficiencies through economies of scale and generally results in more favorable rates and an enhanced quality of service.

(1994 Order Determining Regulatory Treatment, Pages 4, 5, and 7) (Emphasis added.)

Further, the Commission specifically noted therein that "[w]ith the benefit of hindsight, the Commission can now see that the policy to split the gains or losses on sales of water and/or sewer systems has had a negative impact on the public good." In that Order the Commission cited the harmful consequences of its decision with respect to prior cases where proposed sales to municipal/governmental owners either were not consummated, or where the utility demanded a higher price from the municipal purchaser in order to sell the systems.

The Public Staff moved for reconsideration of the 1994 Order Determining Regulatory Treatment in Docket Nos. W-354, Subs 133 and 134. In its November 14, 1994 Order on

Reconsideration, the Commission denied the Public Staff's motion for reconsideration, reaffirmed its findings and conclusions in the Order Determining Regulatory Treatment previously issued therein, and provided the following further insight regarding its decision to assign 100% of gain or loss on sale to the utility's shareholders:

> The Commission [in its September 7, 1994 Order] further concluded that, with the benefit of hindsight, the previous policy to equally share or split the gains or losses on sales of water and/or sewer systems has had a negative impact on the public good and is contrary to the public interest. That being the case, the Commission announced that it would henceforth '**follow a policy, absent overwhelming and compelling evidence to the contrary, of assigning 100% of the gain or loss on the sale of water and/or sewer utility systems to utility company shareholders.** In so deciding, the Commission intends to encourage, to the maximum extent possible, the sale of water and sewer systems to municipalities and other government-owned entities. It is, and shall continue to be, the policy of this Commission to take such actions as will encourage the larger water and sewer utilities with greater operational and capital resources, including governmental entities, to acquire the smaller, under-capitalized, less efficient systems. Such policy serves the public interest by promoting efficiencies through economies of scale and generally results in more favorable rates and an enhanced quality of service.'.

(Order on Reconsideration, issued November 14, 1994, Pages 1 and 2) (Emphasis added.)

The Public Staff appealed the Commission's rulings in those dockets. *State ex rel Utilities Commission v. Public Staff-North Carolina Utilities Commission, supra.* The North Carolina Court of Appeals (Court) affirmed the Commission's decisions, ruling that the findings and conclusions set forth by the Commission supported the decision to allow CWS NC to retain 100% of the gain on sale and that the record before the Commission contained substantial, material, and competent evidence to support the Commission's findings. The Court concluded that

> a reasonable mind would regard the testimony of Daniel and Fernald, along with other materials contained in the record, to adequately support a conclusion that the best interests of the public would be served by allowing CWS to keep 100 percent of the gain on sale of the Farmwood B and Chesney Glen systems. The evidence showed a policy of equally splitting gains on sale would result in a higher purchase price for the Farmwood B system, causing a greater burden for Charlotte-Mecklenburg taxpayers. Also, the contract stated that if CWS was required to share more than 50 percent of the gain with the ratepayers, then the sale could be called off. The evidence also showed the beneficial transfers of privately held utilities to municipal systems had been hampered by a policy of splitting gain on sale. In this case, if CWS had refused to sell the facilities, CMUD would have been forced to duplicate the existing facilities at a high cost. Further, a policy of assigning 100 percent of the gain to the shareholder encourages CWS to make further investments in other smaller water systems, some of which may be undercapitalized or poorly run.

The Court also disagreed with the Public Staff's contention that the Commission's Order was arbitrary and capricious. The Court held that "the Commission gave fair and careful consideration to the issues before it, and that the Commission's final decision was the product of reasoning and the exercise of its judgment." The Court found that "the evidence that is contained in the record to be sufficient to support the Commission's order that CWS retain all of the gain on sale of the Farmwood B and Chesney Glen systems." Lastly, the Court stated that

> Public Staff assigns as error the Commission's statement that '[I]n future proceedings, the Commission will follow a policy, absent overwhelming and compelling evidence to the contrary, of assigning 100% of the gain or loss on the sale of water and/or sewer utility systems to utility company shareholders.' However, this issue is not properly before this Court and we need not decide it.

App 123 N.C. App. at 50.

CWS NC subsequently requested a determination from the Commission as to the regulatory treatment the Commission would authorize in connection with CWS NC's proposed transfer of additional systems to CMU. The Public Staff again advocated that the gain on sale should be shared to mitigate any adverse impact on CWS NC's remaining customers. Again in 1995,[1] and twice in 1996, the Commission reaffirmed its policy of assigning 100% of the gain or loss on the sale of water and/or sewer utility systems to utility company shareholders unless overwhelming and compelling evidence was presented that would support a different distribution.[2]

In the first such ruling in 1996, Order Determining Regulatory Treatment, Docket Nos. W-354, Subs 143 and 145 (March 29, 1996), the Commission stated that it had "long been concerned over the "'troubled water system problem'" and sought to "facilitate the orderly transfer from developers to investor-owned utilities and from investor-owned utilities to municipalities and governmental entities." The Commission concluded that splitting the gain on sale created an economic barrier to achieving these public interests. Additionally, the Commission explicitly rejected the assertion that the Commission's position does not influence the selling price of a utility system as "illogical." The Commission concluded its order by finding that "no evidence, much less overwhelming and compelling evidence, has been presented in this proceeding to warrant the departure from the Commission's current gain on sale position and therefore concludes that the Company should retain 100 percent of the gain on sale."

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1 *See* Docket No. W-354, Sub 140, Order Approving Transfer and Determining Regulatory Treatment of Gain on Sale, February 3, 1995. The Public Staff appealed that ruling, arguing that the Commission's stated intent to apply its policy on treatment of gain on sale exceeded its statutory authority. *State ex rel Utilities Commission v. Public Staff-North Carolina Utilities Commission*, 123 N.C. App. 623, 473 S.E. 2d 661 (1996). The North Carolina Court of Appeals affirmed the Commission's decision adopting the policy of allocating 100% of the gain on sale to the utility company shareholders.

2 On March 29, 1996, in Docket Nos. W-354, Subs 143 and 145, the Commission reaffirmed that policy in its Order Determining Regulatory Treatment of Gain on Sale. The Public Staff appealed that ruling to the North Carolina Court of Appeals, but later withdrew its appeal. The Commission again reaffirmed its gain on sale policy on August 5, 1996, in Docket Nos. W-354, Subs 148-151 and 155-157, in its Order Determining Regulatory Treatment of Gain on Sale.

In the second such ruling in 1996, Order Determining Regulatory Treatment, Docket Nos. W-354, Subs 148-151 and 155-157 (August 5, 1996), the Commission rejected the Public Staff's arguments that (1) the Commission's gain on sale policy did not influence the transfer of the utility systems because CMUD was obligated to extend its lines anyway; (2) CWS NC's contracts were not contingent on treatment of gain on sale; and (3) the loss of customers would reduce economies of scale, but sharing the gain on sale would mitigate the impact. The Commission once again concluded "that the Public Staff has failed to present any new evidence of sufficient probative value to persuade the Commission to alter its current position on the gain on sale issue." The Commission reaffirmed its position of encouraging the "orderly transfer of water systems from developers and small owners to reputable water utilities like CWS and from reputable water utilities to municipalities and other governmental owners." It further stated that "[t]he Commission has endeavored to establish a generic policy that could be relied upon by affected parties in the State of North Carolina so that they could plan their business accordingly." The Commission also concluded that the loss of customers and allocation of costs across a reduced customer base did not constitute sufficient evidence to alter its policy of allocating 100% of the gain on sale to utility shareholders. Furthermore, the Commission stated

> The Commission finds that no new evidence, **much less overwhelming and compelling evidence**, has been presented in this proceeding to warrant the departure from the Commission's current gain on sale position and therefore concludes that the Company should retain 100 percent of the gain on sale. In so concluding, the Commission believes that the current position better serves and promotes the public interest and should be followed in these dockets. (Emphasis added.)

In its subsequent Motion for Reconsideration of the Commission's Order in Docket Nos. W-354, Subs 148, *et al*, the Public Staff argued that the Commission had ignored its argument regarding the impact of the sale of utility systems on the rates of the remaining customers as a grounds for assigning a portion of the gain to ratepayers. By its Order on Motion for Reconsideration (November 27, 1996), the Commission denied the Public Staff's Motion.

In summary, the Commission's analysis of this issue has evolved over the years. The Commission's current policy, as established in the 1994 Order Determining Regulatory Treatment, in Docket Nos. W-354, Subs 133 and 134, is that "the Commission will follow a policy, absent overwhelming and compelling evidence to the contrary, of assigning 100% of the gain or loss on the sale of water and/or sewer utility systems to utility company shareholders." Furthermore, the Commission "has endeavored to establish a generic policy that could be relied upon by affected parties in the State of North Carolina so that they could plan their business accordingly." Since 1994, the Commission has applied this policy.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 8 THROUGH 10

The evidence regarding these findings of fact is contained in the testimony and exhibits of Public Staff witness Fernald, Company witnesses Lubertozzi and Gower, and CMU witness Shearin. Witness Fernald testified that the impact on all affected ratepayers, not just the customers on the systems being transferred, should be reviewed in this proceeding. Witness Fernald further asserted that removing the Cabarrus Woods Systems from uniform rates will have a negative impact on the rates for ratepayers remaining with CWS NC unless the loss of these systems is offset through a sharing of the gain on sale with the remaining ratepayers. The negative impact results from (1) lost economies of scale due to the transfer reducing the number of CWS NC customers, and (2) removal of water and sewer systems with a lower than average cost of service.

Witness Fernald contended that circumstances have changed since prior Commission decisions were adopted that assigned shareholders 100% of the gain on sale of water and sewer systems. The Public Staff opined that in the past the large regulated water and sewer companies who were selling systems, such as CWS NC, were growing in customer base at such a rate that the addition of new customers in other areas would quickly offset the loss of the customers being transferred. Furthermore, witness Fernald observed that in recent years the rate of customer growth for water and sewer companies has declined, and for CWS NC, the number of customers has actually decreased in 2008 and 2009.[1] Due to this circumstance, it is likely that the increase in the cost of service for the remaining ratepayers due to the loss of the Cabarrus Woods Systems will not be offset by customer growth anytime soon. Witness Fernald testified that the detrimental impact on the remaining ratepayers will be especially acute since 13.2% of the customer base under uniform water rates and 24.7% of the customer base under uniform sewer rates will be lost through the sale of the Cabarrus Woods Systems. Further, witness Fernald opined that the lack of customer growth since 2008 indicates that CWS NC will not be able to offset the adverse cost impact experienced when it loses 6,208 water and sewer customers upon transfer of the Cabarrus Woods Systems. The change in circumstance regarding CWS NC customer growth was illustrated by witness Fernald, on Pages 19 and 20 of her prefiled testimony as follows:

Month/Year	Number of CWS NC customers[2]
June 1992	26,077
June 2003	36,587
June 2006	38,031
2008	38,134
2009	37,948
2010	37,946
June 2011	38,046

[1] Although witness Fernald testified that the number of customers for CWS NC has actually decreased during 2008 and 2009, the Commission is unable to determine whether a decline in customers occurred in 2008 because 2007 information was not presented in the chart contained in witness Fernald's prefiled direct testimony. It appears from witness Fernald's chart, which has been included above, that the number of customers decreased in 2009 and 2010.

[2] These numbers show total CWS NC customers, including the Outer Banks systems that are not in uniform rates. Since the June 2011 customer count, CWS NC has lost more customers through the sale of the Corolla Light/Monteray Shores water system. For customers in the CWS NC uniform rate schedule, witness Fernald initially indicated that there are 21,650 water and 14,188 sewer customers, for a total of 35,858. At the hearing, she noted that Nags Head sewer customers should have been removed from those numbers, resulting in a corrected number of 13,585 sewer customers. Therefore, the total number of uniform rate customers is 35,235. The proposed transfer would remove 2,849 water and 3,359 sewer customers, resulting in a total of loss of 6,208, and a total remaining customer count in uniform rates of 29,027.

Company witness Lubertozzi testified that he did not agree with witness Fernald's calculation of the adverse impact on remaining ratepayers because she only included direct expenses and did not include allocated expenses. Witness Lubertozzi calculated the impact on remaining ratepayers to reflect the change in the Water Service Corporation[1] (WSC) expenses allocated to the remaining ratepayers. Witness Lubertozzi reflected in Lubertozzi Exhibit A, Schedules 1(a) and 1(b) attached to his prefiled testimony, that the removal of the Cabarrus Woods Systems would increase the average bill for the remaining ratepayers by approximately $2.17 per month for water operations and $2.05 for sewer operations.

Further, witness Lubertozzi observed that the proposed transaction will remove approximately 2,850 water customers and 3,360 sewer customers from CWS NC's customer base, and will also remove numerous assets from rate base and reduce associated expenses. Witness Lubertozzi explained that CWS NC will experience a reduction in operating, maintenance, and personnel expenses as a result of the transfer, and will also avoid certain capital expenditures that would have been required in upcoming years. Witness Lubertozzi admitted that the anticipated expense reductions would not correlate with the revenue reductions resulting from the transfer.

In rebuttal testimony, witness Fernald implicitly accepted the position of witness Lubertozzi that the impact on remaining ratepayers should include expenses allocated from WSC as well as direct CWS NC expenses. However, she made corrections to witness Lubertozzi's calculation of the allocated expenses. First, witness Fernald pointed out that the total amount of allocated WSC costs was overstated, so she adjusted it according to data from the most recent rate case of a Utilities, Inc. subsidiary in North Carolina.[2] Second, she assigned the allocated WSC costs between water and sewer operations according to the number of remaining water and sewer customers, respectively. Based upon such corrections, in rebuttal testimony, witness Fernald revised her calculated increase to the average water bill for the remaining ratepayers from $3.06 to $2.36 and to the average sewer bill from $3.90 to $2.29.[3] The Company did not challenge witness Fernald's corrections to witness Lubertozzi's calculation of the WSC allocated expenses.

[1] Water Service Corporation is a subsidiary of Utilities, Inc. WSC provides managerial, financing, construction, accounting, operational, and other services to the operating subsidiaries of Utilities, Inc., including CWS NC, and accordingly a portion of WSC expenses are allocated to each of the Utilities, Inc.'s operating subsidiaries.

[2] Witness Fernald noted that the total amount of benefits and payroll taxes provided by the Company for WSC included amounts associated with non-Northbrook employees, which caused the total WSC costs to be overstated. Since the Company was unable to provide the amount of benefits and payroll taxes associated with just the Northbrook employees, witness Fernald used the percentage of benefits and payroll taxes to salaries for the Northbrook employees from the recent CWS Systems, Inc. rate case (Docket No. W-778, Sub 88) to estimate the proper amount to be recognized in this case. The percentage of benefits and payroll taxes to total salaries for the Northbrook employees should be the same for CWS NC as it is for CWS Systems. "Northbrook" refers to the parent company (Utilities, Inc.) and its service subsidiary (WSC), whereas "non-Northbrook" refers to the operating subsidiaries in the various states.

[3] On August 30, 2011, the Public Staff filed Fernald Exhibit I – Revised 8/30/11 which updated witness Fernald's August 15, 2011 rebuttal testimony to revise the impact per month per bill to reflect the exclusion of the Nags Head customers that are not included in CWS NC's uniform rate structure.

Based upon Fernald Exhibit I – Revised 8/30/2011, removal of the Cabarrus Woods Systems from uniform rates would increase the revenue requirement for the remaining ratepayers by approximately $530,000 for water operations and $300,000 for sewer operations, for a total increase in the annual revenue requirement to be borne by the remaining ratepayers of approximately $830,000. Therefore, the removal of the Cabarrus Woods Systems would increase the average bill for the remaining ratepayers by approximately $2.37 per month for water operations and $2.41 for sewer operations. The removal of these systems from uniform rates would increase the average bill for the remaining ratepayers by 5.8% for water operations ($2.37 divided by $40.56) and 6% for sewer operations ($2.41 divided by $40.14).[1]

Witness Fernald testified that based upon the August 30, 2011 revised amounts, in order to offset an upward impact on the revenue requirement of approximately $830,000 per year for the remaining ratepayers, approximately $3.36 million[2] of the gain on sale should be assigned to the remaining ratepayers to protect them from the adverse effects of the sale for a five-year period. Witness Fernald stated that based upon this amount, the remaining ratepayers would receive 17.5% of the gain on sale, and CWS NC's shareholders would receive 82.5%.

Further, witness Fernald asserted that the adverse rate impact will likely persist for years, rather than be offset by new CWS NC customer growth. The transfer of the Cabarrus Woods Systems will result in decreases in the uniform rate customer base of 13.2% for water operations and 24.7% for sewer operations. According to witness Fernald, CWS NC has experienced a net increase in its customer base of only 15 customers in the last five years, from 38,031 as of June 30, 2006, to 38,046 as of June 30, 2011.

Witness Lubertozzi argued that the proposed transfer does not warrant an exception to the gain on sale policy. He stated that the deal arose in the same manner as numerous prior deals with CMU where CWS NC had been faced with either selling its system or losing it through paralleling,[3] and where 100% of the gain on sale was assigned to CWS NC's shareholders. Witness Lubertozzi testified that the mere fact that the selling price is larger relative to book value than in previous sales does not mean the underlying reasons for this sale are different, nor does it mean there are new or different factors in this transaction. CWS NC undertook the same decision-making calculus in this transaction as it does with all situations where it faces the potential paralleling of its system by a municipality. Witness Lubertozzi maintained that

[1] The average monthly bills for CWS NC under present rates of $40.56 for water and $40.14 for sewer are shown on Appendix A of the Order Revising Customer Notice and Granting Extension of Time issued on May 3, 2011, in this docket.

[2] Such calculation is reflected on Fernald Exhibit I – Revised 8/30/2011, Schedule 2.

[3] It appears to the Commission that Company witness Lubertozzi's statement that CWS NC was faced with selling the Cabarrus Woods Systems or losing them through paralleling is an overstatement of the situation. The record in this proceeding indicates that this transaction covers the sale of the assets serving 24 subdivisions; however, based upon a review of the maps included in the Company's application, the testimony of CWS NC witness Lubertozzi, and Exhibit E attached to the testimony of CMU witness Shearin, only nine subdivisions are within the area that was annexed by CMU. Consequently, only those nine subdivisions that are within the annexation area are subject to being paralleled. Since the Company did not provide a customer count by specific subdivision, there is no way to tell how many customers would be subject to paralleling.

Public Staff witness Fernald offered no new evidence or policy reasons in the current docket that were not considered in previous gain on sale cases.

. Furthermore, witness Lubertozzi disagreed with witness Fernald's statement that circumstances have changed since the Commission last addressed the gain on sale issue. He testified that CWS NC has continued to seek to grow its customer base when possible, and that CWS NC's contiguous extensions and requests for new franchises have remained fairly consistent.[1] However, witness Lubertozzi acknowledged that the housing market has suffered significant downturns over the past five years, so organic customer growth has not been as robust as CWS NC would have hoped. He stated that despite the impact of economic conditions on customer growth, cost-based ratemaking has not changed, nor should associated policies. On cross-examination witness Lubertozzi conceded that the proposed transfer would cause diseconomies of scale for CWS NC – diseconomies that will not be offset by cost reductions.

With respect to the Public Staff's assertion that the large number of customers which are subject to being transferred in this proceeding distinguish this case from prior Commission decisions, CWS NC pointed out that in 2005 CWS NC transferred over 2,000 of its customers to the Town of Pine Knoll Shores and experienced a gain on sale of over $2.4 million. On cross-examination, witness Fernald conceded that the Public Staff did not analyze the impact to customers and did not seek to hold remaining ratepayers harmless in that case. For comparison sake, the Company noted that CWS NC is losing approximately 2,900 water customers in the present case.[2] CWS NC asserted that the additional 900 water customers in the present case would hardly be sufficient to warrant a change in the Public Staff's position or a change in the gain on sale policy.

On cross-examination, witness Fernald was asked if there had been "some sort of history" to the Pine Knoll Shores transfer, such as a series of customer complaints involving such matters as water quality, water quantity, or capacity of the system, or similar issues. Witness Fernald responded that she did not recall the specific circumstances associated with the transfer of the Pine Knoll Shores system but stated that in the current proceeding there have been no complaints regarding CWS NC's water and/or sewer utility service and that the systems to be transferred are viable systems.

Company witness Gower testified that changes in circumstances, such as declining customer growth rates, may affect revenue requirements but should not alter the application of

[1] Witness Lubertozzi's statement that CWS NC's contiguous extensions and requests for new franchises have remained fairly consistent is not supported by the record in this docket. First, as noted by witness Fernald, the number of contiguous extensions and franchises filed each year as listed by witness Lubertozzi in his testimony are different from the number of filings each year based on the Commission's docket system. Second, witness Fernald testified that in the past, CWS NC was not filing complete contiguous extensions and franchise applications in a timely manner, and in some cases, the Company was serving customers before a filing was made with the Commission. On cross-examination, witness Lubertozzi acknowledged that for several contiguous extensions, the Company was serving customers years before the Company filed the notification of contiguous extension with the Commission.

[2] Pine Knoll Shores did not provide sewer service, thus only the water figures are used for this comparison. (See Docket No. W-354, Sub 290.)

the principles upon which the rights and responsibilities of the parties rest. He asserted that the public policy reasons enumerated by the Commission in its decisions are not affected by changed circumstances.

The Commission is cognizant of the policy trade-off this transfer creates – while the Cabarrus Woods Systems customers would benefit from the greater economies of scale with CMU, there would also be a loss of economies of scale for the remaining CWS NC customers. If there were sufficiently rapid growth in the CWS NC customer base, it would offset the loss of customers in a transfer and the remaining ratepayers would have some protection from diseconomies of scale. The Commission recognizes that the decline in CWS NC's growth rate in the past few years is due at least, in part, to slow growth in the economy in general. The Commission finds and concludes from the evidence that CWS NC is not likely to offset the loss of the Cabarrus Woods Systems customers through growth anytime in the near future. In this proceeding, the number of customers being transferred is exceptionally large,[1] thereby creating a more significant diseconomy of scale for the remaining customers, and because there is not a rapid growth rate occurring in the customer base of the utility, the adverse cost impact of a transfer of this magnitude will not be so quickly offset. In such situation, a review of the public convenience and necessity under G.S. 62-111(a) requires the Commission to consider the extent of the adverse cost impact on remaining customers and the options for mitigating that impact.

The Commission finds that the proposed transfer would increase the cost of service for the ratepayers who would remain with CWS NC after the transfer. Once this higher cost of service is incorporated into rates in the next CWS NC rate case, it would have an explicit significant adverse impact on the remaining ratepayers. The Public Staff's estimated amount of the adverse impact reflected on Fernald Exhibit I – Revised 8/30/2011 is reasonable given the estimated rate base, revenue, and expense information available in this proceeding. Accordingly, the Commission finds and concludes that the remaining ratepayers in the CWS NC uniform rate structure after the transfer should receive approximately 17.5% or $3.36 million of the gain on sale.

The issue of adverse impact on remaining ratepayers has been addressed by the Commission previously. The August 5, 1996 Order in Docket Nos. W-354, Subs 148-151 and 155-157, specifically noted that losses in economies of scale, which create an adverse impact on remaining ratepayers, are an inevitable consequence of transferring water and sewer systems to municipal owners, and do not justify sharing any gain on sale with remaining ratepayers. The Commission is not now reversing its prior decisions, for they reflect a considered policy judgment made on the basis of the facts and circumstances presented in those proceedings. The Commission concludes that the general policy of providing shareholders with an incentive to sell systems to municipalities, by assigning 100% of the gain on sale to the shareholders, continues to

[1] When the current gain on sale policy was adopted in September 1994 in Docket Nos. W-354, Subs 133 and 134, approximately 202 customers were transferred from CWS NC to CMU at a combined sales price of $380,000. In the 21 CWS NC/CMU transactions that have been brought before the Commission for approval since the current policy was adopted, the maximum number of customers that have been transferred at one time as a result of a sale has been approximately 1,000 customers in Docket Nos. W-354, Subs 178, 179, 180, 181, and 182. However, the Commission has also approved transfer applications involving large numbers of customers, specifically, approximately 2,050 customers in Docket No. W-354, Sub 154 (the Riverbend Community) and 1,807 customers in Docket No. W-354, Sub 290 (Pine Knoll Shores); but neither of these sales involved CMU.

be in the public interest.[1] The Commission also reiterates that a general policy is not to be applied indiscriminately and without consideration of the particular facts in each case. In the 1994 Order that established the general policy of assigning 100% of gain on sale to utility shareholders, the Commission noted that this policy was subject to "overwhelming and compelling evidence to the contrary."[2] While such statement sets a high bar, it has served as a reminder since 1994 that the circumstances in a particular case can justify a different regulatory treatment for gain on sale. The Commission has subsequently underscored the relevance of examining the circumstances in each case:

> In any event, the Commission believes that the propriety of including a gain or loss from the disposition of utility assets, or for that matter a gain or loss of any nature, in utility operations should be determined on the basis of the facts and circumstances of each instance, and not simply because it has been determined that one or the other has been so assigned.[3]

The central question in this case is whether circumstances warrant an exception to the general policy for assigning gain on sale for water and sewer utilities. The Public Staff cites the adverse rate impact on remaining customers as a circumstance in favor of sharing a portion of the gain on sale with the remaining customers. The Commission concludes that there is "overwhelming and compelling" evidence in the present case that justifies an exception to the general policy of assigning 100% of the gain to shareholders.

The following chart, which is included as a point of reference, provides an overview of selected numerical data collected from the evidence presented in this proceeding:

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[1] This "general policy" exists only with respect to the sale of water or sewer systems. The general policy for water and sewer sales is actually an exception to long-standing Commission policy that gain on sale of utility assets normally is assigned 100% to ratepayers. For example, the May 20, 1999 Order in Docket No. SP-122, Sub 0, concludes:

> It is the general policy of the Commission that it is appropriate for ratepayers to receive the benefit of gains realized on the sale or transfer (disposition) of property which has been obtained by the utility in the course of providing regulated public utility service, exclusive of gains realized from the sale of property within the water and/or sewer industry where certain public interest concerns have been determined to outweigh the benefits that would otherwise accrue to consumers.

Thus, the long-accepted ratemaking treatment in North Carolina is to assign 100% of the gains on sale to ratepayers, absent an exceptional circumstance.

[2] September 7, 1994 Order in Docket Nos. W-354, Subs 133 and 134.

[3] May 20, 1999 Order in Docket No. SP-122, Sub 0.

WATER AND SEWER – SALE/TRANSFER

Line No.	Carolina Water Service, Inc. of NC	Water	Sewer	Total
1	Purchase Price – Sale to CMU			$25,700,000
2	Net Book Value (estimated)	$2,495,457	$4,017,234	$6,512,691
3	Gain on Sale (estimated)			$19,187,309
4	Number of Customers to be Transferred	2,849	3,359	6,208
5	Total Number of Customers	21,650	13,585	35,235
6	Percentage of Customers to be Transferred	13.2%	24.7%	17.6%
7	Annual Revenue Requirement Impact (per Public Staff)	$535,108	$295,423	$830,531
8	Impact per Month per Bill (per Public Staff) Percentage Increase	$2.37 5.8%	$2.41 6.0%	$4.78 5.9%
9	Average Monthly Bill (water:4,750 gallons; sewer: flat)	$40.56	$40.14	$80.70
10	Public Staff Recommended Sharing of Gain:			
11	Amount of Gain to Ratepayers	$2,162,928	$1,194,110	$3,357,038
12	Percentage of Gain to Ratepayers			17.5%
13	Amount of Gain to Company			$15,830,271
14	Percentage of Gain to Company			82.5%
15	Public Staff Recommended Amortiz. Period			5 years

Notes: 1. Primary source of information is the Public Staff's August 30, 2011 filing which included Fernald Exhibit I – Revised that reflects the correction noted in witness Fernald's testimony at the hearing; namely, the removal of the Company's Nags Head sewer customers who are not in the uniform rates from the Company's count of its customers under uniform rates.

2. CWS NC's present water rates are $16.81 base charge and $5.00 per 1,000 gallons.

The Commission finds and concludes that there are four circumstances that distinguish this case from prior decisions where 100% of the gain on sale was awarded to shareholders:

(1) This is the first case[1] where the adverse impact on rates of remaining customers has been quantified. It was understandable for the Commission to dismiss concern over the adverse impact on remaining customers in Docket Nos. W-354, Subs 148-151 and 155-157, when there was no evidence to indicate if the impact was negligible or substantial. In the present case, the estimated impact of increases in the average water bill of $2.37 per month (5.8%) and in the average sewer bill of $2.41(6.0%) are significant.

(2) This is the first case where the Commission has been presented evidence that the adverse impact on remaining ratepayers is likely to persist, due to the decline in CWS NC's customer growth rate. The number of CWS NC customers in the uniform rate structure has been essentially flat since 2006. In fact, the number of customers declined in 2009 and 2010. This could be due to the economic downtown or other situations. However, the apparent circumstance that the Company may not be able to quickly replace the substantial number of customers lost in such proposed transfer is exceptional.

(3) An extraordinarily large number of customers, i.e., 6,208 customers, are subject to being transferred. Approximately 24.7% of the CWS NC sewer customers and 13.2% of the CWS NC water customers would be lost from the uniform rate structure as a result of the transfer. This exacerbates the adverse rate impact on remaining customers because the loss of so many customers means a proportionally greater loss of economies of scale. It also increases the amount of time it would take for future growth in the CWS NC customer base to offset the loss of customers to CMU.

(4) Since 1995, CWS NC has filed 21 applications[2] to transfer utility systems to CMU as a result of CMU's annexation practices and extension policies. These sales were sales of necessity due to the city's intent to extend utility service and the resulting parallel threat that CWS NC faced. This instant purchase of the Cabarrus Woods Systems involves the transfer of 24 subdivisions. Of these 24 subdivisions, CMU only approached CWS NC about purchasing the nine subdivisions in its Hood Road South annexation area. The remaining 15 subdivisions were included in the purchase to accommodate CWS NC's business plan.[3] In view of the fact that those subdivisions were outside of CMU's annexation area, CWS NC faced no threat of

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[1] Evidence that quantifies adverse impact on remaining ratepayers has been presented in this docket and in Docket No. W-218, Sub 325 concerning Aqua North Carolina, Inc. The Commission is reviewing these two dockets at essentially the same time.

[2] Does not include the present application.

[3] Based upon a review of the maps included in the Company's application, the testimony of CWS NC witness Lubertozzi, and Exhibit E attached to the testimony of CMU's witness Shearin, the Commission has identified the following nine CWS NC systems included in the Hood Road South annexed area: Brookstead/Cambridge, Brookstead Meadows, Canford Commons, Reedy Creek Run/Brookstead, Turtle Rock, Avensong, Stewart's Crossing, Brawley Farms, and the Preserve at Kinsley Lake. In addition, as previously indicated, six of the 24 subdivisions are located in Cabarrus County and have been proposed to be transferred by CMU to the Town of Harrisburg. Those Cabarrus County subdivisions are as follows: Bradford Park, Victoria Park, Cabarrus Woods, Brookdale, Britley, and a portion of Steeplechase.

being paralleled and losing those customers as a result. Since the adoption of the current gain on sale policy in 1994, CWS NC has brought 24 utility system transfers to the Commission for approval. Twenty-one of those transactions involved the sale and transfer of CWS NC utility assets and customers to CMU. Those prior 24 Commission-approved transfers, which are summarized in Appendix A, attached hereto, collectively, involved the transfer of approximately 7,500 customers for a total collective sales price of over $16.0 million. None of those prior transactions involved individual sales of utility systems for a price of more than $3.75 million or transferred more than 2,050 customers.[1] Indeed, when the current gain on sale policy was first adopted in 1994, in Docket Nos. W-354, Subs 133 and 134, only 202 customers were being transferred in that transaction. While the number of customers being transferred has varied over the years, none of the transfer transactions approved by the Commission have been anywhere near the size and scope of this immediate proposed transaction where a total of 24 subdivisions and the associated customer base of 6,208 customers are subject to being transferred in a single transaction.

The Commission is of the opinion that under G.S. 62-111(a) the interests of all affected parties to a transfer must be considered,[2] and in the circumstances of this case there is overwhelming and compelling evidence of an adverse impact on the Company's remaining ratepayers that is materially different from past cases. The amount of the adverse impact, which could be up to $4.78 per month for those customers who receive both water and sewer service from CWS NC, its likelihood of persisting well into the future, the exceptionally large number of customers being transferred, and the circumstance that over one half of the systems being transferred are not in the annexed area are collectively sufficient reasons for the Commission to adjust the sharing of gain on sale in this proceeding to be different from the usual 100% to shareholders. The Commission finds and concludes that it is reasonable and appropriate to assign an estimated $3.36 million or 17.5% of the gain on sale to the remaining ratepayers in the CWS NC uniform rate structure after the transfer and $15.83 million or 82.5% to shareholders under the proposed transfer application. The apportionment of 17.5% of the gain on sale to the remaining CWS NC ratepayers is necessary in order to offset the extraordinary and exceptional negative impact to such customers.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The evidence regarding this finding of fact is contained in the testimony of Public Staff witness Fernald, Company witness Lubertozzi, and CMU witness Shearin.

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[1] This data was compiled from Public Staff Cross-Examination Exhibit No. 1 and the Commission's orders entered in the dockets cited therein. See Appendix A, attached hereto.

[2] See *State ex rel. Utilities Comm. v. Village of Pinehurst*, 99 N.C. App. 224, 229 (1990):

> We further hold that when the Commission is adjudging public convenience and necessity in the context of proposed transfers of water and sewer franchises under G.S. 62-111(a), it must inquire into *all* aspects of anticipated service and rates occasioned and engendered by the proposed transfer, and then determine whether the transfer will serve the public convenience and necessity.

Company witness Lubertozzi testified that the customers on the Cabarrus Woods Systems have subsidized the other ratepayers because the Cabarrus Woods Systems are lower-cost systems when compared to other systems, and inclusion of the Cabarrus Woods Systems in uniform rates has helped to keep rates slightly lower for the rest of the CWS NC customers. Witness Lubertozzi observed that the Commission, the Public Staff, and CWS NC have consistently promoted a policy of uniform rates due to the associated benefits, since a larger customer base spreads out the cost of service and consolidates and reduces the risks that would otherwise be present in smaller customer groups. Witness Lubertozzi argued that this does not mean that the utility's shareholders should continue to subsidize the remaining ratepayers or that the City's taxpayers should subsidize them by paying a higher price.

CMU witness Shearin testified that the Commission should not place a condition on the transfer of the Cabarrus Woods Systems that could prevent CWS NC's Cabarrus Woods customers from being transferred to the CMU system simply because those customers helped to ensure lower rates for other CWS NC customers. He commented that the effect of the sale of these systems on the remaining ratepayers is largely a function of the imposition of a single rate structure across multiple systems, and the higher-cost systems with "artificially" low rates should not have the ability to block the transfer of systems with "artificially" high rates and prevent the realization of the benefits related to municipal service for those customers.

Public Staff witness Fernald testified that subsidies flow from one system to another in a uniform rate structure, and from one customer to another, and that the benefits of uniform rates justify the cross-subsidies. She pointed out that a "subsidy" from one system or group of systems to others within uniform rates is just a snapshot in time. At an earlier time, low-cost systems might have been higher-than-average cost.

Another example of the difficulty of unraveling cross-subsidies among customers was presented through discussion of storm damages. Hurricane Hugo caused damage that resulted in higher repair costs to CWS NC's Mecklenburg County systems than to CWS NC systems in the rest of the state. Amortization of those costs meant that CWS NC's uniform-rate customers across North Carolina paid for the damage that disproportionately impacted the systems in Mecklenburg County. While witness Lubertozzi was reluctant to call that "subsidization" it is clear that CWS NC's customers outside Mecklenburg County were helping pay for costs attributable to the Cabarrus Woods Systems.

The Commission finds and concludes that it is unfair and inappropriate to characterize a sharing of the gain on sale with remaining ratepayers as forcing CWS NC's shareholders or the City to perpetuate a subsidy to the remaining ratepayers. Nor is it appropriate to say that sharing an extraordinary gain on sale with ratepayers means those ratepayers are paying less than their cost of service. Such arguments ignore that (1) part of the adverse cost impact is the loss of economies of scale, unrelated to any subsidy across systems; (2) the purpose of uniform rates, which is to dampen cost impacts and risks on any one system by spreading them across all systems, may necessarily result in "subsidies" across systems for the greater public benefit; and (3) while the Cabarrus Woods Systems may provide a slight "subsidy" to other systems in the present, some or all of those systems may have been the recipients of subsidies in the past, so a ruling designed to prevent "subsidies" based on the present cost of service may not accurately reflect cost of service over time.

The Commission's prior decision to adopt uniform rates for CWS NC reflected a policy judgment that the public interest would best be served by averaging costs across systems. Accordingly, the Commission is of the opinion that it would now be inconsistent to accept the argument that this has created "artificially" low rates for CWS NC ratepayers outside the Cabarrus Woods Systems.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence regarding this finding of fact is contained in the testimony and exhibits of Public Staff witness Fernald and Company witness Gower.

Company witness Gower testified that sharing the gain on sale as proposed by Public Staff witness Fernald is inconsistent with the regulatory framework that underlies cost-based ratemaking. Witness Gower explained that regulators can limit the returns to be earned from providing utility service to customers, but not on capital transactions, such as the sale of securities held by investors. He asserted that transactions of this nature, whether complete or partial liquidation of an investor's holdings, are capital transactions, and investors should bear the risk of any losses and should be entitled to any gains. Witness Gower maintained that utilities providing service under the regulatory framework of cost-based regulation are entitled to legal protection of their privately-owned property. Among other things, he explained that this means that utilities are entitled to charge a fair and reasonable price which covers the costs they incur to provide service. Although entitled to safe, adequate, and reliable service, customers must pay the fair and reasonable prices set or approved by the applicable regulatory authorities. However, witness Gower opined that customers' rights end with the payment for the service they receive and such payments in no way entitle them to any interest in the property of the utility serving them. Witness Gower further explained that it is the investors - who supply the capital that finances the utility plant serving customers' needs, who own the property financed by their capital, and whose capital is exposed to the risks of ownership.

Public Staff witness Fernald contended that witness Gower is only partially correct in stating that investors supply the capital. She pointed out that a large percentage of the initial installation cost of water and sewer systems is contributed by developers, who in turn recover those costs from ratepayers through the sale of lots. Witness Fernald observed that 55.5% of the plant costs for the Cabarrus Woods Systems have been recovered through CIAC by CWS NC.

The Commission finds and concludes that the arguments advanced by witness Gower are not in accord with ratemaking principles established in North Carolina, and they should be rejected. His position that the gains and losses on capital transactions should flow solely to utility investors should not be adopted for several reasons: First, It is factually flawed. As witness Fernald testified, 55.5% of the plant costs for the Cabarrus Woods Systems have been recovered through CIAC, which represents capital invested in the systems directly or indirectly by customers, not by CWS NC's shareholders. The logical conclusion of witness Gower's theory – allocation of gain on sale to the party that supplied the capital – would be to allocate

55.5% of the gain to the Cabarrus Woods System ratepayers. No party to this proceeding has recommended that outcome and the Commission does not accept it. Second, regulatory authority over gains on sales, just as with expenses, revenues, and capital costs, exists with respect to activity associated with providing utility service to customers. Where a capital transaction is related to utility service, the Commission has the right and responsibility to apply appropriate regulatory judgment and treatment. Lastly, the regulatory framework in North Carolina has long recognized that there are circumstances where it is appropriate to allocate to ratepayers some or all of the gain resulting from sale or transfer of utility assets.

In addition, witness Gower also testified that the USOA, through its detailed instructions, limits amounts recorded in operating expenses to the cost of those resources consumed to conduct utility operations. Witness Gower asserted that capital transactions can be either "investments" or "disinvestments". He explained that construction or purchase of utility facilities would be an "investment" (of investors' capital), while a sale of utility facilities would be a "disinvestment" (of investors' capital). Witness Gower argued that transactions such as the pending sale to CMU, which could be either a complete or partial withdrawal of investors' capital from the utility business, are not related to utility operations, but rather are capital transactions, and that is the reason that the USOA directs accounting which distinguishes them from utility operations.

While the Commission would agree that the USOA distinguishes gains on sale from every day utility expenses, the Commission disagrees with witness Gower's assertion that the USOA requires that a gain on sale of utility property be assigned 100% to shareholders. That assertion simply is incorrect. Accounting Instruction No. 21-G – "Utility Plant Purchased and Sold" of the USOA for Class A water companies provides in pertinent part, that

> "when utility plant constituting an operating unit or system is sold, conveyed, or transferred to another by sale, merger, consolidation, or otherwise, the book cost of the property sold or transferred to another shall be credited to the appropriate utility plant accounts including amounts carried in account 114 – Utility Plant Acquisition Adjustments, and the amounts (estimated if not known) carried with respect thereto in the accounts for accumulated depreciation and amortization and in account 252 – Advances for Construction, and account 271 – Contributions in Aid of Construction, shall be charged to such accounts and the contra entries made to account 104 – Utility Plant Purchased or Sold. <u>Unless otherwise ordered by the Commission</u>, the difference, if any between (a) the net amount of debits and credits and (b) the consideration received for the property (less commissions and other expenses of making the sale) shall be included in account 414 – Gains (Losses) From Disposition of Utility Property." (Emphasis added.)

The USOA classifies Account 414 – "Gains (Losses) From Disposition of Utility Property" as a "Utility Operating Income" account, and states that "this account shall include, when authorized by the Commission, gains and losses from the sale, conveyance, exchange, or transfer of utility property to another." This Commission has the responsibility and authority to prescribe the regulatory accounting treatment it considers appropriate for gain on sale.

For many years the Commission has followed a general policy of assigning 100% of the gain on sale of utility assets to ratepayers. The Commission has also recognized that the sale of water and sewer systems deserve different regulatory treatment from the sale of other utility assets. The difference has nothing to do with the USOA. Instead, the difference is due to the Commission's conclusion that the public interest is generally best served by encouraging transfers of privately-owned water and sewer systems to municipal ownership. This, rather than the USOA, is what has driven the general policy of assigning 100% of the gain on sale to shareholders, absent overwhelming and compelling evidence to the contrary, with respect to disposition of water and sewer systems.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence regarding this finding of fact is contained in the testimony and exhibits of Public Staff witness Fernald, Company witness Lubertozzi, and CMU witnesses Shearin and Hibbard.

CWS NC and CMU witnesses testified that a portion of the gain should not be assigned to the remaining ratepayers because to do so would artificially inflate the sales price that the City may pay for the systems. Company witness Lubertozzi observed that if a utility is forced to share a portion of the gain on sale with ratepayers it will seek to increase the sales price to cover the portion of gain it does not receive. Witness Lubertozzi also explained that a higher sales price would harm city residents because of the higher taxes and/or utility rates to cover the additional costs. Witness Lubertozzi testified that CWS NC will terminate the contract and restart negotiations for the sale of the system if the Commission does not assign 100% of the gain on sale to CWS NC's shareholders.

CMU witness Shearin noted that an increase in the purchase price for the systems would occur during a time of scarce public money that must be used carefully and wisely. CMU witness Hibbard testified that the public interest will be best served by retaining a Commission policy that allows for transfers of existing systems to municipalities at a reasonable price so that critical services for water, health and sanitation, and fire protection can be provided to annexed areas in the most-efficient and cost-effective manner. Witness Hibbard maintained that the public good will best be achieved by a policy that encourages transfers and does not impose artificially high costs on the municipality's taxpayers.

There was conflicting testimony about whether and how much the sales price might increase if the utility could not keep 100% of the gain on sale for its shareholders. CMU witness Shearin stated that there was a chance the City might not be willing to pay a higher price for the Cabarrus Woods Systems if CWS NC terminated the existing contract.[1] Witness Lubertozzi

[1] The witness stated, "The City did feel like they were pushed to a cost level [in the existing contract] that we were seriously looking at whether we can go any higher. We were quizzed – questioned by our board of whether we should be paying this much for a used system." This appears to the Commission to be a serious question, not simply a negotiating tactic, given that the purchase agreement with CWS NC is already at $25.7 million, and witness Shearin testified that in the absence of a purchase agreement the City would expend an additional $10-12 million to serve the annexed areas. Paralleling the CWS NC systems would have other costs, such as disruption caused by digging in the streets and additional fees for residents who wanted to connect to CMU lines, but from the testimony it appears that the out-of-pocket costs to the City could be less than an increased purchase price to CWS NC.

noted that, "A willing buyer and a willing seller can only transact a deal if their respective ranges of a sales price intersect, which is what happened with the CWS NC/CMUD deal...." On cross-examination he indicated "I don't know if the buyer is going to be willing to go up dollar for dollar." Witness Lubertozzi also testified that it is CWS NC's practice to seek the highest price when it negotiates the sale of systems to a municipality on behalf of the shareholder. If this is true – and the Commission has no reason to doubt that CWS NC already negotiated with CMU for the highest price CWS NC could get – then it is questionable whether a higher sales price can be negotiated.

Based upon the specific facts and circumstances in this proceeding, the Commission concludes that the uncertain possibility of an increase in sales price for the Cabarrus Woods Systems is not sufficient reason to leave the remaining CWS NC ratepayers with an adverse cost impact. If a higher sales price is negotiated, it will ultimately be paid by CMU's ratepayers. The Commission does not agree that it should place the interests of CMU's customers before the interests of the remaining ratepayers served by the utility that this Commission regulates. In considering the benefits and costs of its gain on sale policy in this case, the Commission concludes that it is not more appropriate for the 29,000 remaining CWS NC ratepayers to bear this potential increased cost, instead of spreading it over CMU's 250,000 customers where the per customer impact would be much less.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

The evidence regarding this finding of fact is contained primarily in the testimony of Public Staff witness Fernald, Company witness Lubertozzi, and CMU witness Shearin.

Company witness Lubertozzi testified that CWS NC will terminate the contract pursuant to the "escape clause" and negotiate for a higher price if CWS NC does not receive 100% of the gain for its shareholders. No party offered assurance that such a renegotiation would be successful.

CMU witness Shearin testified that if CMU cannot buy the systems from CWS NC, then CMU would install its own facilities and lines for water and sewer service in parallel to those of CWS NC. All parties agree that if the City parallels the CWS NC utility infrastructure, the result would be an uneconomic and inefficient duplication of facilities. To the extent that CWS NC customers switched to CMU, CWS NC would be left with stranded investment in its facilities.

A critical element in determining reasonableness of the incentive for shareholders is evaluation of their alternative. Perhaps CWS NC will be able to negotiate a higher price with CMU, allowing CWS NC to retain as much as $19.2 million in gain even after allocation of a portion to ratepayers. However, if CWS NC terminates the existing contract and is unable to negotiate a higher price, many of its systems will likely be paralleled by CMU. In that event, the CWS NC alternative to accepting the original contract and $15.83 million of gain on sale for its shareholders would be to receive zero gain on sale, loss of customers, loss of revenue, and stranded investment. As witness Lubertozzi testified:

> If CWSNC does not sell the system [Cabarrus Woods Systems], CMUD will parallel the system in order to meet its statutory obligation to provide water and sewer service in the annexed area. CWSNC will lose customers and the resulting revenue stream while stranding the investment in its facilities."[1] [Emphasis added.]

Clearly, a gain on sale of more than $15.83 million is an extraordinary financial incentive for CWS NC compared to the potential costs of being paralleled. Given the stark financial difference between the gain on sale CWS NC would receive when sharing enough with the ratepayers to protect them, and the complete lack of any gain on sale along with potential revenue losses and stranded investment if CWS NC terminates the contract, termination of the contract would certainly be a risky gamble for CWS NC.

As explained by witness Fernald, the estimated $3.36 million portion of gain required to protect the remaining ratepayers from an adverse cost impact for five years would be 17.5% of the total gain on sale. Otherwise stated, the CWS NC shareholders would receive 82.5% of the gain on sale, or an estimated $15.83 million – a "considerable incentive" for CWS NC to go ahead with the sale. The Commission finds and concludes that this is an exceptional financial incentive for CWS NC in this case. While utility shareholders would always prefer 100% of the gain, there are important competing considerations here that must be balanced, including, most importantly, the need to protect the remaining ratepayers from the adverse cost impact of the transfer of 6,208 customers. However, it is also noteworthy that the estimated $15.83 million gain on sale that would accrue to CWS NC's shareholders under the Public Staff's proposal equates to eight times the annual dollar return on equity found reasonable in the most recent CWS NC rate case for the uniform rate structure. The $15.83 million portion of the gain for CWS NC's shareholders that is recommended by the Public Staff represents a 243% return on the net book value of the Cabarrus Woods Systems. It also represents a much higher dollar amount than the CWS NC shareholders received in prior transfers when it was allocated 100% of the gain. In this case, the sharing of gain on sale, as proposed by the Public Staff, would provide CWS NC with a strong and considerable incentive to complete the transfer.

Of course, it is clearly uncertain whether CWS NC would be able to negotiate a higher price for sale of the Cabarrus Woods Systems to CMU under the circumstance that the Commission does not assign 100% of the gain on sale to CWS NC. If CWS NC terminates the existing contract with CMU pursuant to the "escape clause," and is unable to negotiate a new contract for sale of the Cabarrus Woods Systems, it is highly likely that CMU will parallel many of the CWS NC facilities. The Commission recognizes that this would be a poor outcome in terms of the public interest, as discussed hereinabove. In past cases, the Commission sought to avoid the outcome of municipal paralleling of private utilities and to encourage the transfer of systems to municipalities even where there was not a threat of paralleling, by assigning 100% of

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[1] The extent of revenue losses and stranded investment is unknown. Witness Lubertozzi indicated CMU could force all the residents to take CMU water and sewer service, in which case CWS NC would lose all its customers. If CMU paralleled CWS NC and allowed residents to choose their water and sewer utility service, the number of customers who would switch off of CWS NC service would depend at least in part on the level of connection and capacity fees charged by CMU. CMU could waive connection and capacity fees for newly annexed residents if it wished, although there is no indication in the record that CMU would do so.

the gain on sale to the utility shareholders. However, the Commission is of the opinion that the extraordinary circumstances in this case warrant a different approach.

In particular, the Public Staff proposal in this case for a sharing of the gain is more appropriate and reasonable than assigning 100% of the gain to the shareholders, because (1) it would mitigate a significant adverse cost impact on remaining ratepayers, arising from the loss of 6,208 customers, that is otherwise likely to persist for years; (2) the shareholders would still receive a very significant gain (estimate of $15.83 million) and thus a large financial incentive to complete the sale under the terms of the existing contract with CMU; and (3) failure to sell the systems in the annexed area to CMU will expose CWS NC to serious risk of financial losses. The Commission concludes that its decision on whether a portion of the gain on sale should be assigned to the remaining ratepayers should not be controlled by the possibility that the utility might choose to abandon all possible gains from the sale in their entirety, an action that could be construed as imprudent by the Commission.

In addition, the Commission finds and concludes that if CWS NC does not transfer the Cabarrus Woods Systems to CMU, then every six months following termination of the purchase agreement CWS NC should file with the Commission by type of service (water, sewer): (1) a statement of how many customers it has in each subdivision on the Cabarrus Woods Systems; (2) how many CWS NC customers have switched to CMU as a provider; (3) a description of utility plant that has become stranded investment in those systems and the value of such stranded investment; and (4) a statement of the change in revenues and expenses associated with those systems resulting from transfer of customers to CMU.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

Based on the preceding findings and conclusions, the Commission has determined that in this case the gain on sale of the Cabarrus Woods Systems should be allocated between the ratepayers and the shareholders of CWS NC, for the twin purposes of (1) providing CWS NC's shareholders with a reasonable financial incentive to complete the transfer and (2) mitigating the exceptional adverse cost impact of the transfer on CWS NC's remaining ratepayers. Public Staff witness Fernald identified two methods for achieving this sharing. The first method involves amortizing a portion of the gain to the benefit of the remaining ratepayers. The second method would be to deduct the entire gain on sale from rate base, treating it as cost-free capital. Witness Fernald observed that the second method was unlikely to offset the annual amount of the adverse cost impact, so she recommended use of the first method. No other witness supported the second method.

Under the amortization method recommended by witness Fernald, the portion of the gain on sale assigned to ratepayers would be amortized over a specific period of time, with the unamortized balance, net of tax, being deducted from rate base. This would reduce the upward pressure on rates due to the transfer during the amortization period. Witness Fernald recommended a five-year amortization period because of the large dollar amount of the gain in this proceeding, the significant percentage of the uniform customer base being lost due to the sale, and the infrequency of gains and losses related to the sale of water and sewer systems. She testified that a five-year amortization period means every dollar of gain on sale assigned to ratepayers will result in a reduction in the revenue requirement of $0.2474 (Fernald Exhibit I, Schedule 2). Therefore, in order to offset an upward impact of the revenue requirement of approximately $830,000 per year for the remaining ratepayers, approximately $3.36 million of the gain on sale should be assigned to the remaining ratepayers ($830,531 divided by 0.2474) to protect them from the effects of the sale for a five-year period.

The Commission concludes that it is fair and reasonable under the circumstances of this case for an estimated $3.36 million of the gain on sale to be amortized to ratepayers over a five-year period beginning on the date CWS NC receives payment from CMU. The unamortized balance, net of tax, should be deducted from rate base. As discussed elsewhere in this Order, the $3.36 million is an estimated amount, and the actual amount of the gain on sale assigned to ratepayers will be determined once CWS NC provides accurate amounts for the system-specific net investment for the systems being sold.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

The evidence regarding this finding of fact is contained primarily in the testimony of Public Staff witness Fernald, Company witnesses Lubertozzi and Gower, and CMU witnesses Shearin and Hibbard.

As previously stated, since 1994, the Commission's gain on sale policy has been a policy of assigning 100% of the gain or loss of the sale of water and/or sewer utility systems to utility company shareholders, absent overwhelming and compelling evidence to the contrary. For the past 17 years, the Commission's gain on sale policy has been and remains a policy which involves a case-by-case determination of whether overwhelming and compelling evidence exists, based upon the circumstances of each particular proceeding, to warrant an exception to assigning 100% of the gain or loss of the sale of water and/or sewer utility systems to utility company shareholders. In this proceeding, the Commission has determined that based upon the facts and circumstances in this specific proceeding that there is overwhelming and compelling evidence that warrants an exception to the Commission's general policy.

With respect as to what effect finding an exception to the gain on sale policy in this proceeding will have on future transfers, Company witness Gower testified that, as the Commission recognized in past decisions regarding water and sewer utilities, failure to assign gains on sale of systems and operating units to investors would act as an impediment to acquisitions of systems by larger, better financed, and more reliable utilities. CMU witness Shearin testified that if the Commission did not allocate 100% of the gain to the utility, it would make purchases of private systems by municipalities more expensive, and if municipalities were not willing to pay higher prices, the effect would be to prevent the sale of private utility systems to municipalities. CMU witness Hibbard further testified that a change in the Commission's policy, as advocated by the Public Staff, would have the effect of making annexations more difficult and expensive for municipalities, which could result in the undesirable effects of fewer citizens being able to receive the benefits of municipal services and of cities being unable to annex and serve increasingly urbanized areas along their fringes.

The Commission reaffirms the importance of encouraging transfers of privately-owned water and sewer systems to municipal ownership. At the same time, the benefits and costs of each particular transfer to the shareholders, the customers being transferred, and the customers remaining on the system after the transfer has been completed must be carefully considered. In the circumstances of this particular case, even after sharing a portion of the gain with ratepayers sufficient to prevent the remaining ratepayers from being subject to increased rates as a result of the transfer, CWS NC's shareholders would still be expected to receive a substantial and significant incentive of approximately $15.83 million of the estimated $19.2 million gain based on the pending contract.

As to the impact of the Commission's decision in this case on future transfers to municipalities, the general policy continues to be that 100% of gains and losses on the sale of systems will be assigned to shareholders. The continuation of this general policy should continue to promote the orderly transfer to municipalities as in the past. The Commission understands that its recognition of an exception in the particular circumstances of this case will lead some utilities to reassess transfers in the future. However, as with this case, when the transfer of systems will generate a significant gain for shareholders and their alternative is to be paralleled with a resulting loss of revenues stream, stranded investment, and zero gain for shareholders, the Commission believes that it is likely that prudent private utilities will continue to sell their systems to municipalities who have annexed their service areas.

The Commission notes that there have been recent, substantial changes to the annexation statutes which all parties agree will significantly affect how municipalities evaluate areas for annexation. Based on the testimony of CMU witness Hibbard, under the new annexation rules, if property owners for a majority of the parcels in the annexed area "opt-in" to water and sewer services, (1) the municipality must provide water and sewer extensions at no cost to all properties that request it within a certain time frame and (2) the municipality must install individual water and sewer lines to structures on private property at no cost to the property owner. This is a significant change from the prior annexation statues, which allowed municipalities to charge customers connection fees, capacity fees, or similar charges for water or sewer service. The new statutory wording may well increase the cost to municipalities when they annex property.

With respect to the assertions by CWS NC and CMU that they relied on the Commission's current policy in their negotiations, Company witness Lubertozzi testified that if the Commission chooses to alter its gain on sale policy, it would not be fair to apply the change to the transaction contemplated in this docket. He testified that CWS NC and CMU negotiated the current agreement with the expectation that 100% of the gain would be assigned to shareholders, and they should be entitled to rely on established Commission policy and receive the benefit of their bargain. Yet he also testified that during discussions with the Public Staff, the Company came to believe that the Public Staff might challenge the Commission's established policy in this transaction, and thus, as a precaution, the Company included a provision in the contract which allowed it to terminate the contract if 100% of the gain on sale is not assigned to shareholders.

CMU witness Shearin indicated that the negotiations between CMU and CWS NC were based on CWS NC's understanding of Commission policy of allocating 100% of the gain to shareholders. He testified that CMU became aware of a possible Public Staff issue with gain on sale a few days before approval of the contract, when CWS NC notified them it was adding the escape clause. Prior to that notice of a possible Public Staff challenge to the treatment of gain on sale, the evidence is clear that CMU was not conducting its negotiations in reliance on some understanding of Commission policy: At the time of negotiation CMU was not even aware of the Commission's policy and did not know what the regulatory treatment of the purchase price would be.[1]

The Commission is of the opinion that the asserted reliance on policy does not justify leaving the remaining ratepayers without protection from adverse cost impacts in the circumstances of this case. First and foremost, G.S. 62-111(a) requires consideration of the impact of a transfer on all affected parties, and thus the interests of the remaining ratepayers cannot and should not be ignored. The Commission further concludes that any asserted reliance on policy is misplaced in the circumstances of this case. The policy of 100% gain for shareholders has been subject to the "overwhelming and compelling" exception since its inception. Where, as in this case, the evidence supports an overwhelming and compelling reason to share the gain, the Commission is not changing its policy and thus not altering any reasonable reliance by the parties. The Commission is recognizing an exceptional circumstance in accord with the original wording of the policy, for which the parties have had many years of notice. This is especially true in the present case where CWS NC had notice before it signed the contract with CMU that the Public Staff might take exception to assignment of 100% of the gain on sale to CWS NC's shareholders. The actions of CWS NC underscore its knowledge that 100% of the gain might not go to shareholders, as evidenced by the "escape clause" in the contract. The Commission recognizes that CWS NC may not have incorporated into the contract price the possibility of sharing gain with ratepayers, but CWS NC clearly knew the risk when it negotiated with CMU.

In regard to the CWS NC's and CMU's argument that a case-by-case exception would make it difficult for a utility to set a sales price, Company witness Lubertozzi testified that a change in policy would make it nearly impossible to transact in the future, since a utility would not know how to calculate its net proceeds in order to set a sales price. CMU witness Shearin testified that a case-by-case determination of the adverse impact on the remaining ratepayers would involve multiple steps of analysis, including (1) a determination of whether the sale will have a material negative effect on the remaining ratepayers; (2) a determination of the specific impact of the sale on the remaining ratepayers' rates; and (3) a determination of the amount of gain that should be allocated to ratepayers to compensate for the negative effect on the rates. Witness Shearin contended that the process of deciding whether a portion of the gain should be assigned to the remaining ratepayers would be complicated and administratively inefficient, and that such case-by-case determinations would necessarily require time-consuming review of the utility's net investment in the assets to be transferred, the utility's remaining assets, and the

[1] Moreover, CMU has spent $53 million on water and sewer infrastructure to serve new areas of eastern Mecklenburg County. This expenditure was necessary to serve the annexed areas, but will also allow service to other areas not part of the 2009 annexation. This large expenditure was made without regard to the potential purchase of the CWS NC systems; witness Shearin testified that if CWS NC was not involved then CMU would still have spent "virtually all" the $53 million on water and sewer expansion in any event. Almost none of this investment will be "stranded" if the contract with CWS NC is terminated.

utility's projected cost of service and revenue requirements after the transfer. He asserted that the addition of these issues in transfer dockets would result in disputed proceedings. Witness Shearin further maintained that a case-by-case determination of the specific gain amount needed to protect remaining ratepayers would discourage transfers of private water and sewer utilities to municipalities and sanitary districts.

Public Staff witness Fernald testified that the determination of impact on remaining customers would be an objective calculation based on the revenues, rate base, expenses, and number of customers in each case. She maintained that the information should be readily available to any utility that has kept adequate records. On cross-examination she was asked about the number of months that could elapse before CWS NC filed system-specific information, determined the exact amount of gain on sale, obtained review by the Public Staff, and resolved any disagreements whether in hearing or otherwise. The implication was that a sharing of the gain on sale would delay the transfer by months. Witness Fernald replied that CWS NC could negotiate the sale and transfer the systems prior to filing system-specific data and that CWS NC could expedite the calculations for the systems being sold.

The Commission concludes that the timing concern is not sufficient reason to allow CWS NC to retain 100% of the gain on sale for its shareholders. As witness Fernald observed, how fast the system-specific data is provided remains within the control of CWS NC. Indeed, the Commission required CWS NC to maintain system-specific data in its June 10, 1994 Order in Docket No. W-354, Sub 128. While no party can guarantee a regulatory outcome in advance, the utility certainly can calculate any adverse impact on remaining ratepayers in a potential transfer, and that calculation should allow the utility to negotiate with a sufficient understanding of how much gain it might be allowed to retain.

In regard to CWS NC's and CMU's request that any change to the Commission's gain on sale policy should be administered on only a prospective basis rather than in the current proceeding, the Commission reiterates that the decision reached in the present case does not represent a change in its long-standing gain on sale policy. Instead, our decision reflects that overwhelming and compelling evidence exists that requires the Commission to find and conclude that an exception to the general policy of assigning 100% of the gain to shareholders should be made in this immediate proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 17

The evidence regarding this finding of fact is contained in the testimony of Public Staff witness Fernald and Company witness Lubertozzi. Public Staff witness Fernald testified that during her review of the system-specific net investment information provided by the Company, she noted several potential problems with the system-specific data. First, she stated that there was a difference between the gross plant, net of CIAC, as of December 31, 1992, provided by the Company in this case and the amounts provided by the Company in Docket No. W-354, Sub 128. Second, the Company did not check the accuracy of the plant, CIAC, PAA, accumulated depreciation, and accumulated amortization amounts for each system during its computer system conversion in 2007. Third, witness Fernald explained that the Company did not include certain water and sewer system assets that are installed and in service on the systems being sold. Instead, those assets continue to appear on the Company's books as part of the Charlotte warehouse business unit, even though the assets have been moved from the warehouse and deployed on specific systems, including the systems that are being sold. Finally, witness Fernald maintained that the Company did not provide an accurate listing of plant, CIAC, and PAA, indicating additions and retirements by year, by plant account, and that without this information, she was unable to determine the accuracy of the plant, CIAC, PAA, accumulated depreciation, and accumulated amortization amounts for the systems being sold.

Further, witness Fernald noted several problems with the depreciation and amortization schedules provided by the Company, including (1) the recording of a credit to PAA in one year, when there were no additions to plant and CIAC for that year; (2) instances where the Company recorded a credit to CIAC prior to any additions being shown for plant; and (3) at least one instance where additions to a system were listed prior to the date the Company entered into a contract to acquire the system. Witness Fernald testified that in response to her data requests concerning these potential problems, the Company indicated that the years listed for each addition or retirement on its depreciation and amortization schedules for the systems being sold were not accurate.

In Docket No. W-354, Sub 128, the Commission ordered the Company to continue to maintain system-specific data for all of its systems. To remedy the failure of CWS NC to follow the Commission's Order from Docket No. W-354, Sub 128, witness Fernald recommended that the Company be required to compile accurate system-specific data for all of its systems, including the systems being sold. Furthermore, witness Fernald recommended that none of the costs related to compiling accurate system-specific data at this time be borne by ratepayers, as the Company was required to maintain system-specific data in the Sub 128 proceeding.

Company witness Lubertozzi observed that he reviewed the available financial data from the Sub 128 time period; and it does not appear that the Company recorded or adjusted its system-specific balances at that time to match the report prepared by Arthur Anderson in the Sub 128 proceeding. Witness Lubertozzi further testified that the Company had kept system-specific data since the Sub 128 proceeding. As to the difference due to the 2007 computer system conversion, witness Lubertozzi asserted that the Company reconciled the balances under the old and new systems, and the rate base variance between the balances at conversion was $42,915, which is immaterial to the Company and the proposed divestment. Witness Lubertozzi further stated that the Company does not believe a restatement of the rate base for the systems being sold is necessary. He also explained that after the Company provided the system-specific net investment information to the Public Staff, it came to the Company's attention that the dates on the report were inaccurate and irrelevant to the depreciation or accumulated depreciation schedules. Witness Lubertozzi acknowledged that the Company could probably file the system-specific data as recommended by the Public Staff for the systems being sold within two or three months.

The Commission understands that CWS NC has not maintained system-specific data adequately on its books. Although Company witness Lubertozzi testified that the misstatement in the system-specific data due to the 2007 computer conversion of $42,915 is immaterial, he acknowledged that (1) there is a difference between the system-specific data provided in this case and that provided in the Sub 128 proceeding and (2) the dates on the system-specific data provided to the Public Staff by the Company are inaccurate. However, he did not provide any information concerning the impact of correcting these problems on the rate base for the systems being sold. Finally, witness Lubertozzi did not address the Company's failure to include in system-specific net investment the assets installed and in service in those systems that are still recorded under the Charlotte warehouse business unit on the Company's books.

Accurate system-specific data, including the years for each addition and retirement, should have been maintained for all systems, as previously ordered by the Commission in Docket No. W-354, Sub 128. This data is needed, for the systems proposed to be sold, in order to determine the actual amount of the gain on sale to be assigned to ratepayers in this case. The Company should be required to file accurate system-specific data for all of its systems. Since there is a more immediate need for the system-specific data related to the systems being sold, the Commission concludes that it is reasonable and appropriate for CWS NC (1) to file, within two months of the date of this order, system-specific data as requested by the Public Staff, including a corrected list of plant, CIAC, and PAA additions and retirements by year for each of the systems proposed for sale to CMU; (2) to file a final calculation of the net book value and the annual level of depreciation and amortization expense for each of the systems sold to CMU within 45 days of the closing of the transfer or the filing of corrected system-specific data, whichever comes later; and (3) an updated calculation of the gain on sale assigned to the remaining ratepayers using the methodology set forth in Fernald Exhibit I – Revised 8/30/2011, within 45 days of the closing of the transfer or the filing of corrected system-specific data for the systems being sold, whichever comes later. The Commission finds and concludes that the Public Staff should review the Company's updated calculations and file comments within 30 days of the Company's filing of the updated gain on sale calculation.

As for the remaining systems, the Commission finds and concludes that it is reasonable and appropriate for CWS NC to file system-specific data, as recommended by the Public Staff, within six months of the date of this Order. Finally, CWS NC should accurately record the costs of preparing the system-specific data for all of its systems so those costs may be excluded from the cost of service charged to ratepayers.

IT IS, THEREFORE, ORDERED as follows:

1. That CWS NC shall file system-specific data, including a corrected list of plant, CIAC, and PAA additions and retirements by year, for each of the systems proposed for sale to CMU, within two months of the date of this Order.

2. That, if there is a closing, CWS NC shall file a final calculation of the net book value and the annual level of depreciation and amortization expense for the systems proposed for sale to CMU within 45 days of the closing of the transfer or the filing of corrected system-specific data for those systems, whichever comes later.

3. That CWS NC shall file an updated calculation of the gain on sale assigned to the remaining ratepayers using the methodology set forth in Fernald Exhibit I – Revised 8/30/2011, within 45 days of the closing of the transfer or the filing of corrected system-specific data for the

systems being sold, whichever comes later. Thereafter, the Public Staff shall review the Company's updated calculation and file comments within 30 days.

4. That based upon the circumstances of this proceeding, an estimated $3.36 million or 17.5% of the gain on sale shall be apportioned to the remaining ratepayers in the CWS NC uniform rate structure after the transfer and $15.83 million or 82.5% to shareholders under the proposed transaction in order to offset the extraordinary and exceptional negative impact to such customers.

5. That CWS NC shall amortize the gain on sale assigned to the remaining ratepayers over five years, beginning when and if the transfer closes.

6. That CWS NC shall file system-specific data, including a corrected list of plant, CIAC, and PAA additions and retirements by year, for each of its remaining systems, within six months of the date of this Order.

7. That CWS NC shall accurately record the costs of preparing the system-specific data for all of its systems so those costs may be excluded from the cost of service charged to ratepayers.

8. That if CWS NC does not transfer the Cabarrus Woods Systems to CMU, then every six months following termination of the purchase agreement, CWS NC shall file with the Commission by type of service (water, sewer): (a) a statement of how many customers it has in each subdivision on the Cabarrus Woods Systems; (b) a statement of how many CWS NC customers have switched to CMU as a provider; (c) a description of utility plant that has become stranded investment in those systems and the value of such stranded investment; and (d) a statement of the change in revenues and expenses associated with those systems resulting from the customers choosing to be served by CMU.

ISSUED BY ORDER OF THE COMMISSION
This the 23rd day of December, 2011.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

fh122311.01

Commissioner ToNola D. Brown-Bland concurs in part and dissents in part.

Chairman Edward S. Finley, Jr., did not participate.

DOCKET NO. W-354, SUB 331

COMMISSIONER TONOLA D. BROWN-BLAND CONCURRING IN PART AND DISSENTING IN PART: *In the Matter of Application by Carolina Water Service, Inc. of North Carolina*, Docket Nos. W-354, Subs 133 and 134, by Order dated September 7, 1994, the Commission held for the first time, in a 4-1 decision, that "absent overwhelming and compelling evidence to the contrary," 100% of the gain or loss on the sale of water and/or sewer utility systems would be assigned to utility company shareholders. On numerous occasions since that time, as noted in the majority opinion, the Commission has followed and affirmed that holding. In fact, today's majority yet again affirms the holding from the cited Order. I concur with the majority to the extent it affirms the holding from the 1994 Commission Order, but in all other respects, I respectfully dissent from the majority opinion.

I. Since 1994, the Commission has Assigned 100% of the Gain on Sale to Shareholders to Promote Its Policy of Encouraging the Orderly Transfer of Utility Systems

As noted in the majority opinion, in all dockets prior to today where the stated 1994 holding was applied, the Commission has determined that 100% of the gain on sale of water and sewer systems should be assigned to the shareholders of the utility company in furtherance of the stated policy goal of encouraging, to the maximum extent possible, the sale of water and sewer systems to municipalities and other government-owned entities. "Order Determining Regulatory Treatment of Gain on Sale of Facilities," Docket No. W-354, Subs 133 and 134, p. 7 (September 7, 1994). The Commission has explained in docket after docket that encouraging the orderly transfer of water and sewer systems from developers and small owners to reputable private service providers to municipalities and other governmental owners is in the public interest[1] and that assigning 100% of the gain on sale of such systems to utility shareholders will have the Commission's intended effect of encouraging the orderly transfer of systems through the stated progression of ownership.[2] I agree with such stated policy goal to promote this orderly transfer of systems.

II. The Majority's Decision Will Introduce Uncertainties That Will Not Promote the Commission's Policy of Encouraging the Orderly Transfer of Ownership of Water and Sewer Utility Systems.

[1] The reasons this progression of ownership transfer is in the public interest are explained in many of the dockets cited in the majority opinion and will not be repeated here.

[2] In this docket, as well as other past dockets, the Public Staff has suggested that the Commission should at least allow the ratepayers of water and sewer systems to receive a portion of any gain on sale since the Commission usually requires 100% of the gain from the sale of assets in other regulated industries, such as electric and natural gas, be assigned to the ratepayers. However, it should be noted that, in the other non-water/sewer industries, the Commission does not have a stated policy of encouraging the sale of system assets to other service providers; other providers are not free to offer service in the service territory assigned to the certificated public utility; and the customers generally are not in a position to become customers of another provider as long as they reside or do business in the service territory of the public utility.

In the instant docket, the majority proclaims that it remains Commission policy to encourage the orderly transfer of water and sewer systems from small private owners to larger well-established private utility companies to municipal and governmental providers. The majority further states that its holding in support of assigning 100% of the gain on sale to company shareholders, but making an exception in this proceeding due to overwhelming and compelling reasons or evidence to do so, "should continue to promote the orderly transfer to municipalities as in the past." It "*should*" except for the fact that the majority's determination that there is overwhelming and compelling reason and/or evidence to require sharing of the gain (17.5% to ratepayers and 82.5% to shareholders) reintroduces uncertainty into the transfer process, particularly during the negotiation stage between the buyer and the seller, resurrects many of the uncertainties that past Commission determinations sought to remove from the process, and will likely introduce new uncertainties as well.

A. Uncertainties pertinent to the CWS NC-CMU sale and acquisition –

Company witness Lubertozzi testified that the Company would terminate its current contract with CMU for the purchase and sale of system assets and restart negotiations, if the Commission decides not to assign 100% of the gain to the shareholders. Presumably, the Company would take this action to negotiate an increase in the sales price to cover the portion of gain it would be denied by having to share a portion of the gain with ratepayers. Clearly, the mere reopening of negotiations between CWS NC and CMU introduces uncertainty by placing the current sales transaction and bargained-for deal in jeopardy. It was exactly this type of uncertainty and jeopardy that led the Commission to move away from an equal sharing of gain between ratepayers and shareholders to assigning 100% of the gain to shareholders to encourage system sales to municipalities. In the above-cited September 1994 Order, the Commission noted that requiring sharing of the gain had the unintended consequence of creating a barrier to the orderly transfer of systems from private utility companies to municipalities. Therein, the Commission cited instances where transactions were terminated and never consummated or sales prices were artificially increased to cover the part of the bargain the seller would not receive following Commission determinations that gain on sale must be shared.

If negotiations are reopened in the present docket, CWS NC could lose the benefit or full value of the bargain it negotiated. There is no guarantee or certainty that CMU would consider paying additional money to CWS NC or that it would even have additional funds available nearly a year after initial negotiations ended with the agreed-upon deal.

Furthermore, if CMU is unable or unwilling to increase its purchase price, rather than lose the benefit of its bargain, CWS NC could attempt to restructure its proposed sale and transfer of assets, for example, by selling only those nine systems that actually serve the areas annexed by the City of Charlotte.[1] Such deal restructuring might allow CWS NC to receive what it considers the full and fair value of the nine systems, while CMU could conceivably agree to a total payment less than what it had agreed to for 24 systems. As will be discussed below, restructuring the transaction as described would likely cause further delay in closing the sale.

Restructuring the deal to sell only those systems serving annexed areas presumably would result in fewer customers leaving the uniform system and in less lower-cost systems being sold. That being the case, the restructured transaction would likely not impact the existing system economies of scale to the same degree as in the transaction which is the subject of the majority's analysis. It follows, therefore, that any negative impact to CWS NC's remaining customer base would be less than the impact resulting from the sale of the 24 systems. While (assuming all underlying numbers that would be used in the adverse impact calculation are known and agreed upon)[2] CWS NC may be able to calculate the dollars needed to offset the adverse impact to remaining customers, the Company would still have no way of knowing whether it would be required to assign a portion of the gain to ratepayers without the added delay of returning to the Commission for a determination of the treatment of gain. This is because the majority's conclusion in this proceeding that the gain must be shared is based on the specific facts that were before the Commission and the majority's opinion offers no standard by which to determine whether there is overwhelming and compelling reason to assign any part of the gain on sale to the ratepayers. In other words, only the Commission is in a position to know when such an overwhelming and compelling reason in favor of sharing gain exists and it will know overwhelming and compelling when it sees it. If the parties change the terms of the proposed transaction and/or there is a change in the adverse impact to customers, then the determination of whether the gain has to be shared may also change, but only the Commission will have the answer.

If this uncertainty is not apparent from the determination in this docket, it certainly becomes apparent when the majority opinion in the instant case is read in tandem with the majority opinion in a companion case—*In the Matter of Application by Aqua North Carolina, Inc.*, Docket Nos. W-218, Subs 325, 327, and 319—also decided today. In the instant docket and in the *Aqua NC* matter, the Public Staff made the same basic showing, *i.e.*, a quantified adverse impact, the loss of lower-cost systems and a significant number of customers that were part of

[1] The majority's determination turns in part on the fact that CWS proposes to sell 15 systems that did not serve annexed areas and that are not subject to be paralleled. The majority seems to suggest that the sale of these 15 systems is a reason not to assign 100% of the gain to the shareholders. While one might draw a negative inference from the Company's decision to sell these additional systems, there are many inferences that could be drawn, including some that are positive. While the evidence in the record does not explain, beyond accommodation of its business plan, why CWS agreed to sell the additional systems, it could have been for reasons related to operational efficiencies and cost containment just as easily as it could have been for the purpose of securing a good return on investment for its shareholders. The point is that the evidence in the record does not explain the reason for selling the additional systems and there is no more reason to draw a negative inference from such decision than there is to draw a positive inference.

[2] Witness Shearin testified that the process of deciding whether a portion of the gain should be assigned to the remaining ratepayers would be complicated and administratively inefficient, and such case-by-case determinations would necessarily require time-consuming review of the utility's net investment in the assets to be transferred, the utility's remaining assets, and the utility's projected cost of service and revenue requirements after the transfer. Witness Shearin contended that the addition of these issues in transfer dockets would result in disputed proceedings.

the uniform rate structure, low customer growth, and the loss or reduction of economies of scale. In both matters, the Public Staff also sought to apply a portion of the gain on sale to offset the adverse impact on rates resulting from a sale of utility systems that were part of a uniform rate structure. Despite the presence and establishment of the same factors in both cases, the majority reaches a different outcome in *Aqua NC*, concluding that the evidence in that matter presented no overwhelming or compelling reason not to assign 100% of the gain to Aqua NC shareholders. In my view, the main distinction that apparently justified the majority's treating the gain in the two proceedings differently is that in *Aqua NC*, the number of systems and customers leaving the uniform system are fewer, thus resulting in a slightly lower increase in the rates that will be charged to the remaining uniform rate structure customers.[1]

However, while it is conceivable, perhaps even probable, that if CWS NC restructures the proposed sale so that it results in a slightly lower rate increase to the customers remaining in the uniform rate structure, the Company's shareholders may be permitted to keep 100% of any gain on sale, CWS NC would simply still have no way to determine with any level of certainty how the Commission would treat the gain on sale issue. The two Commission opinions issued today leave this determination completely within the Commission's unguided, unrestricted discretion.

Therefore, if CWS NC and CMU renegotiate their proposed transfer of systems, CWS NC would almost certainly be required to return to the Commission in order to understand how any gain on sale would be treated. This added delay in the process of transfer could further interfere with any prospect of orderly transfer of private water systems to governmental ownership, against the public interest. CMU is already beyond the time by which it should be providing water and sewer service to its annexed area as required by law and therefore may determine that waiting for one more decision from the Commission imposes another delay it cannot afford. Accordingly, because today's decision brings uncertainty rather than clarity to the issue of treatment of gain on sale, transfer of the systems at issue could be in greater jeopardy regardless of whether the Company and CMU might be able to agree on new terms.

The foregoing discussion serves only to demonstrate a few of the foreseeable uncertainties that could result from today's decision. It appears the majority is unable to see the uncertainties because it is persuaded that the size of the gain it assigns to shareholders, 82.5% of the gain or $15.83 million, provides "an extraordinary financial incentive" for closing on the proposed sale. The majority concludes that "[$15.83 million] is an exceptional incentive for CWS NC in this case;" that this portion of the sales proceeds "equates to eight times the annual dollar return on equity found reasonable in the most recent CWS NC rate case for the uniform rate structure;" that this portion of gain "represents a 243% return on the net book value" of the systems being sold; and that with the 82.5% portion of gain assigned by the Commission, "the shareholders would still receive *a very significant gain* (estimate of $15.83 million) and thus *a large financial incentive* to complete the sale under the terms of the existing contract with CMU [emphasis added]." The majority sends a clear message that it believes CWS NC should not take issue with sharing $3.36 million with the ratepayers because it will still receive over $15 million, a superior alternative to receiving nothing which is what might happen if the existing contract for sale of the systems is terminated.

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[1] The adverse impact for the CWS NC remaining sewer customers is $2.41 per customer per month; for Aqua NC, the amount is $1.96 per sewer customer per month – a difference of only $0.45 per month.

However, CWS NC's right to cancel the contract for sale provides it with choices other than going forward with the proposed transaction or receiving no compensation for its systems. The choices may or may not be workable but they exist. Thus, it is clear from the Commission's history with the gain on sale issue, as well as from testimony of witness Lubertozzi, that we cannot know with any degree of certainty whether the Company and CMU will go forward with the proposed sales transaction for the sale and acquisition of the Cabarrus Wood Systems in light of the Commission's decision to require sharing of the gain on sale. In fact, if CWS NC viewed the receipt of $15.83 million as the extraordinary incentive the majority sees, it could have long ago in the course of this docket acquiesced to the Public Staff's position that $3.36 million of the gain be shared with ratepayers. CWS NC's continued opposition to sharing this amount of the gain would tend to suggest that the Company does not view $15.83 million to be quite the strong incentive the majority believes it is. In my view, today's decision by the Commission will serve to inject further uncertainty into circumstances surrounding the proposed sales transaction at issue because the record before us establishes that CWS NC is at least as likely to cancel the existing contract and attempt to renegotiate price and/or restructure of the sale as it is to go forward based on the current agreement.

B. Uncertainties pertaining to future opportunities for the transfer of water and sewer systems –

I believe the decision of the majority will also create uncertainties with respect to future opportunities to transfer private systems to municipal or governmental ownership. Because today's decision appears to rest in large part on the negative impact to CWS NC's remaining uniform rate customers caused by the transfer of several systems resulting in the loss of over 6,000 customers from the uniform rate structure, I believe that rather than risk the loss of bargained-for gain, regulated utilities will understandably spend considerable time structuring future sales to avoid loss of large numbers of customers in a single transaction. Instead of perhaps acting in the most efficient manner dictated by sound business practices, utilities will attempt to split or piecemeal sales, knowing that the Commission will make case-by-case determinations as to the treatment of gain on sale. Following the reasoning of today's opinion, the fewer customers and the fewer lower-cost systems removed from the uniform rate structure at one time, the less negative impact to the remaining uniform customers. Accordingly, in that situation, as demonstrated by the *Aqua NC* opinion, the Commission will be less likely to find the existence of any overwhelming and compelling reason to require sharing of any gain on sale. Thus, I believe today's decision could lead not only to inefficient business behavior, but also to the inefficient use of Commission time and resources as a result of needless increases in the number of transfer and gain on sale dockets brought to the Commission in an effort by utilities to protect their shareholders' interest in gains from the sale of company assets.

Moreover, I believe today's decision requiring sharing of the gain on sale could negatively impact the willingness of the larger water and sewer utilities with service territories in North Carolina to acquire high-cost, troubled systems and include them in a uniform rate structure. The higher-cost systems increase the average cost of service, thereby increasing all customers' monthly bills for service across the uniform rate structure. It is precisely this increase which results from the acquisition and inclusion of troubled systems in a uniform rate structure that contributes heavily to the negative adverse impact to the remaining uniform rate customers when lower-cost systems are sold. The higher-cost, troubled systems are as much responsible for driving the remaining customers' bills up as is the exit of the lower-cost systems. Realizing that the gain on sale may be allocated where the Commission finds it appropriate to offset the negative impact to remaining customers, i.e., the increased cost of service, companies may be discouraged from taking on troubled systems and encouraged to keep their uniform costs of operation as low as possible by refusing to purchase or acquire these high-cost systems. Therefore, I believe today's decision does not support the Commission's policy of encouraging larger private utilities to acquire troubled systems and keep service rates affordable for the customers of the troubled systems by taking advantage of the economies of scale that can be achieved from spreading all the costs across the customers of the uniform system.

Furthermore, because the majority opinion in effect finds it reasonable and appropriate to assign "a portion" of the gain on sale to ratepayers in order to offset a rate increase resulting from the sale of the Cabarrus Woods Systems, it signals to companies that they may not only be required to share future gains on sale but may, in some instances be required to assign all of the gain to the ratepayers. The negative impact or increase in rates to be offset by "a portion" of the gain on sale is calculable and does not change based on the amount of gain that is realized from a sale of assets. For example, in the instant case the $2.37 adverse impact on a water customer and the $2.41 adverse impact on a sewer customer would remain the same whether the gain on sale is $19.2 million, $3.36 million, or $1.0 million. Clearly, if the gain on sale were either of the latter two amounts, the portion of gain required to offset the adverse impact to the remaining uniform customers would leave the company shareholders receiving no part of the gain. While it could be the case that a sales transaction resulting in a cost impact that is higher than the gain is a bad or imprudent transaction, there could also be legitimate business reasons to complete such a sale. The parties may for whatever reason have negotiated the best possible price under circumstances unknown to us today. However, under the reasoning of today's decision, because such marginal sales could result in the shareholders receiving little or no portion of the gain, they may never go forward. In essence, the majority's opinion could have the unintended consequence of discouraging all such sales, thereby, creating an economic barrier to the orderly transfer and perhaps leading to higher costs of service to all uniform customers due to the inefficiencies of holding on to systems and customers that could best be served by other providers.

Because today's decision is based on assigning a portion of gain to offset adverse customer impact it opens the door to a whole range of gain-sharing possibilities, some of which could leave the shareholders receiving little or no portion of the gain received. Consequently, I believe today's decision creates uncertainty that could serve as a future barrier to the orderly transfer of systems to governmental entities and threatens the Commission's policy of encouraging larger utilities to acquire smaller troubled systems for the good of the public interest. In my opinion, in cases where sharing of gain is appropriate, it would be better to provide utilities with certainty by establishing set percentages of the gain that ratepayers and shareholders would receive rather than suggesting that ratepayers should receive any portion of the gain necessary to prevent their rates from increasing. In order to foster and encourage investment in the water and sewer industry in North Carolina, it is critical in my view that Commission decisions provide a level of predictability and certainty for sound business planning and operation and for the attraction of capital investment. Commission decisions should not introduce uncertainty that interferes with the ability of utilities to freely conduct their business. In my opinion, the majority's decision introduces just such unnecessary uncertainties.

III. The Majority's Decision Finding Overwhelming and Compelling Evidence to Assign Less Than 100% of the Gain on Sale to Shareholders Ignores Commission Precedent.

The majority finds four circumstances that distinguish the present case from prior decisions awarding 100% of gain on sale to shareholders and that establish overwhelming and compelling evidence to permit the Commission to adjust the sharing of gain on sale to protect ratepayers from the extraordinary and exceptional negative impact that would result from consummation of the proposed sale of the Cabarrus Wood Systems. I will address each of the four circumstances below.

First, the majority finds that this case is the first case in which the adverse impact on the rates of remaining customers has been quantified. The majority opinion states it was "understandable" that the Commission would "dismiss" concerns of adverse impact in the absence of quantification. I find these conclusions astonishing and incorrect to the extent they suggest that, in its previous decisions, the Commission did not consider adverse impact to remaining ratepayers, and that if the impact had been quantified, gain on sale in those cases may have received different treatment.

Past decisions of the Commission make it abundantly clear that the Commission has always been aware that, more often than not, sales of systems that are part of a uniform rate structure will result in loss of economies of scale and adverse impact to customers remaining in the uniform rate structure. In particular, in a prior Order, the Commission stated

> As its third reason in support of its position, the Public Staff indicates that the Company has common costs, such as rent and accounting fees, which it will incur regardless of the loss of customers in this case. Due to the loss of customers, argues the Public Staff, the remaining ratepayers will have to pay a higher amount per customer of these costs, all other things being equal.
>
> The Commission concluded that these factors relied upon by the Public Staff fail to support a change in the Commission's current position. The current Commission position applies **irrespective** of whether the system sold is relatively costly or inexpensive to operate. . . . .
>
> Furthermore, <u>to the extent there are losses of economies of scale</u>, **such losses are the inevitable consequence of the process whereby there is an orderly transfer of systems to a municipality *and do not justify awarding a portion of the gain on sale to ratepayers.***

In the Matter of Application by Carolina Water Service, Inc. of North Carolina, Docket No. W-354, Sub 148, p. 12 (August 5, 1996) (Emphasis added). To suggest that quantification is a new and material element that would have changed prior holdings is to disregard the clear meaning of express language in prior Commission opinions. As exemplified by the excerpt above, the Commission was aware that there was negative impact to remaining customers, realized that the impact could be significant, and made it obvious that quantification of the amount of the impact was not necessary or in any way determinative of its rulings. The Commission concluded that losses of economies of scale (unqualified/unquantified) did not justify awarding "a portion" of gain on sale to ratepayers in contravention of the Commission's policy to encourage municipal acquisition of private water and sewer systems. The Commission further noted that its position was not at all dependent on whether losses of economies of scale were due to transfers of high- or low-cost systems.

Moreover, if quantification of such losses or adverse impact had been in any way material to the Commission's prior reasoning and decisions, the Commission would not have let the matter drop due to the manner in which the Public Staff presented its case! I have every confidence given the numerous times the gain on sale issue was before the Commission, that on at least one of those occasions, at least one or more Commissioners participating in the cases would have asked for quantification and the Commission would have allowed it to be entered into the record by late-filed exhibit, if need be, if quantification would have had any bearing.

In short, past Commission decisions expressly held that negative impacts caused by the loss of economies scale did not justify assigning a portion of gain on sale to ratepayers. It necessarily followed from such holdings that losses caused by losing the advantages of scale, no matter the magnitude, did not present overwhelming and compelling evidence to stray from the position of awarding 100% of gain to shareholders. Accordingly, I cannot agree that the quantified amount of the adverse impact justifies a finding of overwhelming and compelling evidence to support sharing a portion of the gain with ratepayers in the instant proceeding.[1]

Second, the majority finds that for the first time there was evidence presented to the Commission suggesting that the quantified adverse impact to ratepayers was likely to persist due to the decline in the Company's customer growth rate. I am uncomfortable basing the Commission's ruling on forecasting the future economy. If this case had been heard in 2007, it is unlikely the Commission would have foreseen the downturn in the economy that reared its head in 2008, and I do not believe the Commission has expertise in predicting whether, when, or how quickly the economy will experience a boom. If boom times unexpectedly begin in a year or two, the adverse impact to customers may not persist for five years, but the remedy imposed by the majority does not allow for any adjustment to this sharing of gain.

However, the more important point with respect to *persistence* of adverse impact is that if quantification of adverse impact has been previously considered and ruled out as a reason for sharing gain on sale, then persistence of adverse impact should likewise have no bearing on the Commission's decision and should not serve as a basis for finding overwhelming and compelling

[1] While it is true that prior Commissions cannot bind the current Commission, inasmuch as the Commission functions as a court of original jurisdiction in the context of this proceeding, it would seem in accord with sound regulatory and judicial principles that when the Commission is presented with virtually the same arguments, the same evidence, and well-established precedent, one could expect to obtain a similar result or outcome unless the law or policy underpinning prior decisions had changed. In this proceeding, underlying law and policy have not changed.

evidence to support sharing gain in light of the 1994 holding on the gain on sale, which the majority affirms in this case.

The third circumstance the majority uses for support of its finding of overwhelming and compelling evidence is the "extraordinarily large number of customers" subject to being transferred. The majority concludes, "this exacerbates the adverse rate impact on remaining customers because . . . [of] a proportionally greater loss of economies of scale." While the large numbers may exacerbate the negative impact on customers, exacerbated or not, the quantified adverse impact accounts for and includes the high level of customer loss. In other words, the size of the customer loss only supports the quantification of the adverse impact and should not serve as a separate reason in support of overwhelming and compelling evidence. Moreover, as discussed above, quantification itself should not support reaching a different conclusion from those made in prior cases.

Finally, the majority's fourth reason in support of its finding of overwhelming and compelling evidence — the size and scope of the customer base to be transferred in this single transaction — appears to be merely a restatement or refinement of its third reason. Again, it is the number of customers leaving the system, whether the customers are inside or outside the annexed area, which the majority discusses as being harmful to the remaining uniform rate structure customer base. The number of systems transferred, the number of customers transferred, and the overall magnitude of what is proposed for transfer all support and are accounted for in the quantified numbers, which show the adverse impact to customers. These numbers do not provide a reason separate and apart from the quantified impact for finding overwhelming and compelling evidence to require sharing of the gain on sale. In addition, as discussed above, quantification itself should not support, and, in my view, does not support reaching a different conclusion on the treatment of gain on sale than the Commission has reached in its prior decisions.

In conclusion, for all the reasons discussed hereinabove, among others, I respectfully dissent from the majority opinion.

\s\ ToNola D. Brown-Bland
Commissioner ToNola D. Brown-Bland

APPENDIX A

Line No.	Docket Sub No.	Date of Filing	Date of Order	Name	Purchaser	Total No. of Customers	Sales Price	Original Cost Net Investment
1	143	1/30/1995	3/29/1996	Hidden Hills.	CMUD	90	$ 173,000	$ 46,912
2	145	5/18/1995	3/29/1996	Habersham	CMUD	133	266,000	62,531
3	148	8/25/1995	8/5/1996	Hampton Green/Courtney I and II	CMUD	227	405,000	45,925
4	149	8/25/1995	8/5/1996	Idlewood	CMUD	92	174,000	40,551
5	150	8/25/1995	8/5/1996	Wood Hollow/Brandywine	CMUD	197	445,000	137,831
6	151	8/25/1995	8/5/1996	Providence West	CMUD	99	184,000	48,695
7	154	1/16/1996	3/18/1996	Riverbend	Riverbend	2,050	3,036,100	915.877
8	155	1/16/1996	8/5/1996	Southwoods	CMUD	153	341,893	49,760
9	156	1/16/1996	8/5/1996	Saddlebrook	CMUD	55	106,000	35,601
10	157	1/16/1996	8/5/1996	Suburban Woods	CMUD	94	70,000	46,225
11	178	5/16/1997	6/11/1997	Farmwood A/Applecreek	CMUD	309	865,900	189,051 [1]
12	179	5/16/1997	6/11/1997	Lawyers Station	CMUD	270	239,300	145,879
13	180	5/16/1997	6/11/1997	Farmwood 15, 20, 21	CMUD	298	785,500	70,091
14	181	5/16/1997	6/11/1997	Brandonwood	CMUD	29	85,300	1,788
15	182	5/16/1997	6/11/1997	Tarawoods	CMUD	71	865,900	189,051 [1]
16	195	12/29/1997	2/10/1998	Parks Farm	CMUD	350*	1,937,800	180,765
17	201	6/17/1998	8/17/1998	Williams Station	CMUD	42	92,415	[2]
18	202	7/15/1998	8/17/1998	Bainbridge	CMUD	150	388,685	341,768
19	204	9/22/1998	11/24/1998	Providence Ridge Rox/Hearthstone	CMUD	189	396,320	78,096
20	217	4/15/1999	6/2/1999	Habersham, et al.	CMUD	275	1,200,000	(118,955)
21	242	8/4/2000	6/18/2001	Matthews Commons	CMUD	131	103,250	5,852
22	243	7/21/2000	9/21/2000	Farmington	CMUD	44	90,000	25,362
23	251	5/14/2001	5/22/2001	Sequoia Place	Winston-Salem	324	450,000	259,002
24	290	9/16/2005	9/26/2005	Pine Knoll Shores	Pine Knoll Shores	1,807	3,750,000	1,621,116
	Total					7,479	$16,451,363	

* Order states 350 customers; application states approximately 350 water and 350 sewer customers.

[1] Divestments were combined in report to Commission.

[2] Company did not provide information in data request response.

The data included in this appendix was compiled from Public Staff Cross-Examination Exhibit No. 1 and the Commission orders entered in the dockets cited therein. In addition to the 24 transactions listed above, on July 5, 2011, in Docket No. W-354, Sub 332, the Commission issued an Order Approving Transfer of Water Systems to Owner Exempt from Regulation. Such transaction transferred approximately 1,310 water customers at a negotiated sales price of $3.5 million; the original cost net investment was approximately $5.0 million.

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(11700 Painted Tree Rd., Charlotte, NC)	E-7, SUB 902	(03/10/2011)
(120 Vista Grande Cr., Charlotte, NC)	E-7, SUB 965	(03/10/2011)
(32 Smyth Ave., Hendersonville, NC)	E-7, SUB 971	(03/10/2011)
(390 Business Park Dr., Winston-Salem, NC)	E-7, SUB 972	(03/10/2011)
(8320 E. Highway 150, Terrell, NC)	E-7, SUB 973	(03/10/2011)
(1408 Courtesy Rd., High Point, NC)	E-7, SUB 974	(03/10/2011)
(11550 Statesville Blvd., Cleveland, NC)	E-7, SUB 975	(03/10/2011)
Progress Energy Carolinas, Inc.		
(Madison County, Marshall, NC)	E-2, SUB 993	(04/06/2011)

Dominion North Carolina Power - E-22, SUB 380A; Order Approving Code of Conduct Amendment (05/10/2011)

Duke Energy Carolinas, LLC - E-7,
SUB 795A; Order Accepting Financing Plan (03/07/2011)
SUB 953; Order Approving Program (03/31/2011)

Progress Energy Carolinas, Inc. - E-2, SUB 847; Order Approv. Revision to Progress Energy's Balanced Bill Payment Plan (10/24/2011)

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Dominion North Carolina Power - E-22, SUB 462; Order Approving 2009 REPS Report (09/30/2011)

Duke Energy Carolinas, LLC - E-7,
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North Carolina Municipal Power Agency Number 1 - E-43, SUB 6; Order on 2008 REPS Compliance Report (05/03/2011); Errata Order (05/18/2011)

Progress Energy Carolinas, Inc. - E-2,
SUB 991; Order Approving Waiver Request (02/09/2011)
SUB 995; E-7, SUB 980; Order Closing Advance Notice Dockets (04/27/2011)
SUB 1003; Order Approv. Reallocation of Decommissioning Fund Contributions (07/11/2011)

ELECTRIC – Rate Increase

Duke Energy Carolinas, LLC - E-7, SUB 909; Order Approving Rider (06/28/2011)

ELECTRIC – Rate Schedules/Riders/Service Rules and Regulations

Dominion North Carolina Power - E-22,
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Meadow Lake Wind Farm II LLC	EMP-53, SUB 0	(03/30/2011)
Meadow Lake Wind Farm IV LLC	EMP-54, SUB 0	(03/30/2011)
MinnDakota Wind, LLC	EMP-45, SUB 0	(01/03/2011)
Meadow Lake Wind Farm III LLC	EMP-56, SUB 0	(03/30/2011)
Moraine Wind LLC	EMP-44, SUB 0	(01/03/2011)
Moraine Wind II, LLC	EMP-43, SUB 0	(01/03/2011)
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Pyron Wind Farm, LLC	EMP-59, SUB 0	(07/12/2011)
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Exelon Wind 9, LLC – EMP 21, SUBS 0 & 1; Order Amending Registration of New Renewable Energy Facility (07/29/2011)

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BMA Eden Apartments, LLC		
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BMA Huntersville Apartments, LLC		
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BMA Lakewood, LLC		
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BMA Monroe III, LLC		
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(Bell Southpoint Apartments)	WR-185, SUB 7	(10/04/2011)
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