ONE-HUNDREDTH REPORT

OF THE

NORTH CAROLINA

UTILITIES COMMISSION

ORDERS AND DECISIONS

ISSUED FROM
JANUARY 1, 2010 THROUGH DECEMBER 31, 2010

ONE-HUNDREDTH REPORT
of the
NORTH CAROLINA UTILITIES COMMISSION

ORDERS AND DECISIONS

Issued from

January 1, 2010, through December 31, 2010

Edward S. Finley, Jr., Chairman

*Robert V. Owens, Jr., Commissioner

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.

*Retired effective February 28, 2010
**Sworn in on April 15, 2010, replacing Robert V. Owens, Jr.

LETTER OF TRANSMITTAL

December 31, 2010

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, 2010, we hereby present for your consideration the report of the Commission's significant decisions for the 12-month period beginning January 1, 2010, and ending December 31, 2010.

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

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Renné Vance, Chief Clerk

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DOCKET NO. E-100, SUB 113

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
Rulemaking Proceeding to Implement Session	)	ORDER ON MOTION FOR
Law 2007-397	)	CLARIFICATION

BY THE COMMISSION: On January 8, 2010, Green Energy Solutions NC, Inc. (GES), filed a motion for clarification in the above-referenced docket. The motion states that the company's process for producing methane gas, which is subsequently used for electricity generation, involves the anaerobic digestion of swine or poultry waste as well as "other biodegradable material." GES requests clarification as to whether all of the electrical output produced by the resulting methane is eligible to count toward the REPS swine or poultry waste set-aside obligations established for electric power suppliers by Session Law 2007-397.

GES cites the Commission's May 7, 2009 Order on Duke Energy Carolinas, LLC (Duke), Motion for Clarification, in which the Commission stated that:

> for any facility that uses swine or poultry waste to produce energy, the facility shall earn RECs that may be credited toward meeting the set-aside requirements based only upon the energy derived from the swine or poultry waste in proportion to the relative energy content of the swine or poultry waste and the other fuels used. To the extent that a portion of the other fuels used are also renewable energy resources, the facility may earn RECs associated with the other renewable fuel sources.

GES argues that the Commission's approach is not readily applicable to GES's anaerobic digestion process, wherein swine or poultry waste is mixed with other organic, biodegradable materials and together digested to produce methane. GES asserts that, since the resulting methane is the only product combusted to produce electricity, there is no other "fuel" mixed with the swine or poultry waste, as envisioned in the Commission's May 7, 2009 Order. Green Energy argues that all the methane produced by the anaerobic digestion process should collectively count toward the respective poultry waste or swine waste carve-out and, thus, 100% of the generator's electric output should qualify.

GES also states that, "while it is possible to process swine, poultry waste, or the co-substrates individually through the anaerobic digestion process the net output of biogas will be significantly less than from a combined mixture of the same mass input."

The Commission is not persuaded that all of the methane gas produced in the manner GES describes should qualify toward the REPS poultry or swine waste set-asides. The "other organic, biodegradable material" that GES mixes with the poultry or swine waste is responsible for some percentage of the resulting methane gas. All of the methane gas is not produced from the digestion of the poultry or swine waste, and, therefore, all of the generated electricity (and associated renewable energy certificates, or RECs) cannot count toward the poultry or swine waste set-asides. Consistent with its decision in the May 7, 2009 Order, only RECs associated with the percentage of electric generation that results from methane gas that was actually produced by poultry or swine waste may be credited toward meeting the set-aside requirements. Where other biomass materials contribute to some portion of methane gas production, that portion of RECs shall not count toward meeting the poultry or swine waste set-asides.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 20th day of January, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

kh012010.01

DOCKET NO. E-100, SUB 113

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Rulemaking Proceeding to Implement	)	ORDER ON WITHDRAWAL OF
Session Law 2007-397	)	JOINT MOTION, ISSUANCE
	)	OF JOINT REQUEST FOR
	)	PROPOSALS, AND ALLOCATION
	)	OF AGGREGATE SET-ASIDE
	)	REQUIREMENTS

BY THE COMMISSION: On August 14, 2009, Progress Energy Carolinas, Inc. (PEC); Duke Energy Carolinas LLC (Duke); Dominion North Carolina Power (Dominion); North Carolina Electric Membership Corporation (NCEMC); North Carolina Eastern Municipal Power Agency (NCEMPA); and North Carolina Municipal Power Agency Number 1 (NCMPA) (jointly, the Electric Suppliers) filed a Joint Motion requesting that the Commission modify the swine and poultry waste resource set-aside requirements of the North Carolina Renewable Energy and Energy Efficiency Portfolio Standard (REPS), G.S. 62-133.8(e) and (f), and clarify the obligations thereunder. Specifically, the six Electric Suppliers requested that the Commission (1) delay the poultry waste set-aside requirement by one year and reduce the requirement by two-thirds; (2) delay the swine waste set-aside requirement by one year; and (3) declare that it is not in the public interest for an electric power supplier to buy electricity from a renewable generating facility unless the contract terms include fixed prices or other price risk mitigation provisions. Four of the Electric Suppliers – Dominion, Duke, NCEMC and PEC – also requested that the Commission modify the poultry waste set-aside requirement to require an electric power supplier to meet only a pro rata share of the total obligation.

On August 31, 2009, the Commission issued an Order requesting that the Public Staff and other interested parties file responses to the Electric Suppliers' Joint Motion.

On September 2, 2009, the Citizens for a Safe Environment; the Citizens Alliance for a Clean, Healthy Economy; the Sampson County Citizens for a Safe Environment; and the Blue Ridge Environmental Defense League, Inc. (the Community Groups), filed a petition to intervene, which petition was allowed by Order dated September 18, 2009. On September 18, 2009, the North Carolina Poultry Federation, Inc. (Federation), filed a petition to intervene, which intervention was allowed by Order dated September 25, 2009.

Comments were filed by the Community Groups; the Federation; Montgomery, Sampson and Surry Counties; Environmental Defense Fund, Southern Alliance for Clean Energy, and Southern Environmental Law Center (Environmental Intervenors); Fibrowatt LLC (Fibrowatt); North Carolina Farm Bureau Federation, Inc. (NCFB); North Carolina Pork Council (NCPC); North Carolina Sustainable Energy Association (NCSEA); Orbit Renewable Energy Systems (Orbit); and the Public Staff.

On October 6, 2009, the Commission issued an Order scheduling an expedited evidentiary hearing for December 8, 2009, to consider the issues raised in the Joint Motion and establishing deadlines for the filing of testimony and proposed orders and briefs. The Order was mailed to all electric power suppliers in North Carolina.

On October 13, 2009, the Public Works Commission of Fayetteville filed a petition to intervene, which petition was granted October 16, 2009. On November 9, 2009, Sampson County filed a petition to intervene, which petition was granted on November 13, 2009. Petitions to intervene were filed on November 18, 2009, by Surry County, on November 20, 2009, by Montgomery County, and on November 23, 2009, by Green Energy Solutions NV, Inc. (GES), all three of which were granted by Order dated December 1, 2009.

The direct testimony of J. Michael Surface was filed on behalf of Dominion; Owen A. Smith on behalf of Duke; Carl Strickler on behalf of Fibrowatt; Julian Cothran on behalf of GES; David Beam on behalf of NCEMC; Matthew E. Schull of behalf of NCMPA; Walter Pelletier on behalf of the Federation; David Kent Fonvielle on behalf of PEC; Deborah M. Johnson on behalf of the NCPC; Judy Stevens on behalf of Montgomery County; Jackie Morris on behalf of Montgomery County; and David Mickey on behalf of the Blue Ridge Environmental Defense League and the Community Groups. Rebuttal testimony was filed by R. Craig Hunter on behalf of Surry County.

On December 4, 2009, a Joint Motion was filed by the Electric Suppliers, Fibrowatt, and GES requesting that the Commission reschedule the filing of rebuttal testimony and the evidentiary hearing in this matter. On that same day, the Commission issued an Order continuing the evidentiary hearing pending further order of the Commission and extending the deadline for rebuttal testimony up to and including December 18, 2009.

On December 16, 2009, the Electric Suppliers filed to withdraw the Joint Motion with regard to their requests that the Commission: (1) delay the poultry waste set-aside requirement of GS 62-133.8(f); (2) reduce the poultry waste set-aside requirement; and (3) declare that it is not in the public interest for the Electric Suppliers to purchase electricity from a renewable generation facility unless the proposed prices are fixed or contain reasonable price risk mitigation. The Electric Suppliers further requested that the Commission delay ruling on the pro rata allocation issue until they had submitted a settlement agreement for Commission approval.

On January 20, 2010, NCPC filed a petition to intervene, which petition was granted February 4, 2010.

On January 22, 2010, PEC filed a letter on behalf of the Electric Suppliers stating that they had met with swine waste generation parties and agreed that they would submit for Commission approval (1) an agreement for the pro rata allocation of the aggregate statewide swine waste resource set-aside obligation among the State's electric power suppliers and (2) a generic request for proposals (RFP) from swine waste generators. The letter stated that the RFP would contain a date by which all bids would be submitted and that the Electric Suppliers and swine waste generation parties, after reviewing the bids, would determine the number of megawatt-hours and/or renewable energy certificates (RECs) that can realistically be produced by 2012. If the number of megawatt-hours and/or RECs is less than the 2012 requirement, the parties will jointly petition the Commission to reduce the 2012 requirement in GS 62-133.8(e) to a level that can realistically be achieved.

On January 29, 2010, PEC filed the joint swine waste resource RFP on behalf of itself, Dominion, Duke, NCEMPA, NCMPA, and GreenCo Solutions, Inc. (GreenCo), for approval by the Commission. PEC stated that approval of the RFP is supported by Dominion, Duke, GreenCo, NCEMPA, NCMPA, PEC, Fibrowatt, GES, NCPC, NCSEA, the Attorney General and the Public Staff. NCEMC has also indicated its support of the RFP. In support of approval of the RFP, the parties stated:

> A jointly issued RFP for swine waste generated electricity will assist all parties in coordinating swine waste proposals and in determining the amount of swine waste generation that can realistically be expected to be available in 2012 to meet the set-aside requirement. The parties need to issue the RFP on February 15, 2010 in order to process the bids, execute contracts and have plants under construction by the end of 2010. Thus, we ask for expedited approval of the RFP.

On February 5, 2010, PEC filed a proposed mechanism to allocate between and among the State's electric power suppliers the statewide aggregate poultry waste and swine waste set-aside requirements established by G.S. 62-133.8(e) and (f). PEC stated that the mechanism was supported by Dominion, Duke, PEC, GreenCo, NCEMC, NCSEA, NCPC, Fibrowatt, GES, the Attorney General and the Public Staff. PEC stated that Carolina Industrial Group for Fair Utility Rates I, II, and III (CIGFUR) did not have sufficient time to take a position prior to the filing of the proposed mechanism. PEC stated that ElectriCities of North Carolina, Inc. (ElectriCities), does not support the proposed mechanism as written.

DISCUSSION AND CONCLUSIONS

In its May 7, 2009 Order on Motion for Clarification, the Commission addressed several issues regarding the statewide aggregate set-aside requirements for swine and poultry waste resources. With regard to the determination of each electric power supplier's obligation, the Commission stated that "the electric power suppliers are charged with collectively meeting the aggregate requirement" and agreed with the Public Staff's comments "that the language of the swine and poultry waste set-aside provisions contemplate that the electric power suppliers may agree among themselves how to collectively satisfy the requirements of those subsections." In response to Duke's further request that the Commission "clarify that joint procurement or other collaborative efforts among electric power suppliers to obtain resources to meet the state-wide poultry waste and swine waste carve-out requirements is clearly articulated and affirmatively expressed as a State policy, and that the Commission believes that its oversight of REPS compliance constitutes active supervision by the State of this policy" pursuant to Parker v. Brown, 371 U.S. 341 (1943), the Commission stated:

> The Commission concludes that the REPS statute and the Commission's rules implementing Senate Bill 3 constitute active supervision of the electric power suppliers' activities. Under the procedures established by statute and by rule, the electric power suppliers are required to file annual REPS compliance plans and reports with the Commission, the Commission is required to review and approve the annual REPS compliance reports, and the Commission is required to annually report to the legislature and the Governor on the efforts undertaken by the electric power suppliers to comply with the REPS requirement. To alleviate any remaining concerns whether such collaborative efforts would be lawful under the "state action" doctrine, the Commission shall require that the electric power suppliers specifically file for approval any joint procurement agreements entered into or other collaborative efforts undertaken to obtain renewable energy or RECs to satisfy the aggregate swine or poultry waste set-aside requirements.

The Commission is encouraged by the progress evidently achieved by the parties with regard to the poultry waste resource set-aside requirement and finds good cause to allow the Electric Suppliers to withdraw their requests in the Joint Motion that the Commission: (1) delay the poultry waste set-aside requirement of GS 62-133.8(f); (2) reduce the poultry waste set-aside requirement; and (3) declare that it is not in the public interest for the Electric Suppliers to purchase electricity from a renewable generation facility unless the proposed prices are fixed or contain reasonable price risk mitigation. The Commission continues to urge all electric power suppliers to work together to collectively meet the statewide aggregate poultry waste resource set-aside obligation and comply with G.S. 62-133.8(f).

The Commission further concludes that issuance of the joint RFP is reasonable as a means for the electric power suppliers to work together collectively to meet the swine waste resource set-aside requirement and approves its issuance for purposes of the state action immunity doctrine. The Commission reserves the right, however, to resolve any issues or differences that may arise among bidders or potential bidders and the electric power suppliers with regard to the RFP. In addition, the Commission states that approval of issuance of the RFP does not constitute approval of the final costs associated therewith for ratemaking purposes, and this order is without prejudice of any party to take issue with the ratemaking treatment of the final costs in a future proceeding. The Commission notes that, pursuant to G.S. 62-133.8(a)(6), RECs purchased for REPS compliance are not required to include all environmental attributes.

Lastly, the Commission notes that the proposed pro rata allocation of the aggregate swine and poultry waste resource set-aside obligations has wide, but not unanimous support among the electric power suppliers. As stated before, the Commission encourages the electric power suppliers to agree among themselves how to collectively satisfy the aggregate requirements of those subsections. Nevertheless, as evidenced by the parties' filings in this docket, the aggregate requirement has continued to be a barrier to significant progress toward meeting the swine and poultry waste resource set-aside requirements. In support of approval of the proposed pro rata allocation mechanism, the moving parties state that such approval "will provide clarity and certainty" regarding each electric power supplier's obligation to purchase swine and poultry waste generation. Although the Commission is inclined to agree with the movants that the proposed pro rata allocation is reasonable and should be approved, it will allow ElectriCities, NCEMPA, NCMPA and any other interested party to file comments on or before February 26, 2010 on this issue.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 12th day of February, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Kc021210.01

DOCKET NO. E-100, SUB 113

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Rulemaking Proceeding to Implement Session Law 2007-397	) ORDER ON PRO RATA) ALLOCATION OF AGGREGATE) SWINE AND POULTRY WASTE) SET-ASIDE REQUIREMENTS AND) MOTION FOR CLARIFICATION

BY THE COMMISSION: On August 14, 2009, Progress Energy Carolinas, Inc. (PEC); Duke Energy Carolinas LLC (Duke); Dominion North Carolina Power (Dominion); North Carolina Electric Membership Corporation (NCEMC); North Carolina Eastern Municipal Power Agency (NCEMPA); and North Carolina Municipal Power Agency Number 1 (NCMPA) (jointly, the Electric Suppliers) filed a Joint Motion requesting that the Commission modify the swine and poultry waste resource set-aside requirements of the North Carolina Renewable Energy and Energy Efficiency Portfolio Standard (REPS), G.S. 62-133.8(e) and (f), and clarify the obligations thereunder. Specifically, the six Electric Suppliers requested that the Commission (1) delay the poultry waste set-aside requirement by one year and reduce the requirement by two-thirds; (2) delay the swine waste set-aside requirement by one year; and (3) declare that it is not in the public interest for an electric power supplier to buy electricity from a renewable generating facility unless the contract terms include fixed prices or other price risk mitigation provisions. Four of the Electric Suppliers – Dominion, Duke, NCEMC and PEC – also requested that the Commission modify the poultry waste set-aside requirement to require an electric power supplier to meet only a pro rata share of the total obligation.

On December 16, 2009, the Electric Suppliers filed to withdraw the Joint Motion with regard to their requests that the Commission: (1) delay the poultry waste set-aside requirement of GS 62-133.8(f); (2) reduce the poultry waste set-aside requirement; and (3) declare that it is not in the public interest for the Electric Suppliers to purchase electricity from a renewable generation facility unless the proposed prices are fixed or contain reasonable price risk mitigation. The Electric Suppliers further requested that the Commission delay ruling on the pro rata allocation issue until they had submitted a settlement agreement for Commission approval.

On January 22, 2010, PEC filed a letter on behalf of the Electric Suppliers stating that they had met with swine waste generation parties and agreed that they would submit for Commission approval (1) an agreement for the pro rata allocation of the aggregate statewide swine waste resource set-aside obligation among the State's electric power suppliers and (2) a generic request for proposals (RFP) from swine waste generators. The letter stated that the RFP would contain a date by which all bids would be submitted and that the Electric Suppliers and swine waste generation parties, after reviewing the bids, would determine the number of megawatt-hours and/or renewable energy certificates (RECs) that can realistically be produced by 2012. If the number of megawatt-hours and/or RECs is less than the 2012 requirement, the parties will jointly petition the Commission to reduce the 2012 requirement in GS 62-133.8(e) to a level that can realistically be achieved.

On January 29, 2010, PEC filed the joint swine waste resource RFP on behalf of itself, Dominion, Duke, NCEMPA, NCMPA, and GreenCo Solutions, Inc. (GreenCo), for approval by the Commission.

On February 5, 2010, PEC filed a proposed mechanism to allocate between and among the State's electric power suppliers the statewide aggregate poultry waste and swine waste set-aside requirements established by G.S. 62-133.8(e) and (f) (Proposed Pro Rata Mechanism). In summary, the Propose Pro Rata Mechanism provides (1) that the statewide aggregate swine and poultry waste set-aside requirements shall be allocated among all of the electric power suppliers based upon the ratio of each electric power supplier's prior year's retail sales to the total retail sales; (2) that an electric power supplier shall be deemed to be in compliance with the swine or poultry waste set-aside requirement once it has satisfied its allocated share of the statewide aggregate requirement or has reached its incremental cost cap pursuant to G.S. 62-133.8(h); (3) that no electric power supplier shall be obligated to satisfy more than its allocated share of the statewide aggregate swine or poultry waste set-aside requirement; and (4) that, upon approval of the Commission, the electric power suppliers may jointly procure renewable energy resources in order to satisfy their individual allocated shares of the statewide aggregate swine or poultry waste set-aside requirements.

PEC stated that the Proposed Pro Rata Mechanism was supported by Dominion, Duke, PEC, GreenCo, NCEMC, NCSEA, North Carolina Pork Council (NCPC), Fibrowatt LLC (Fibrowatt), Green Energy Solutions NV, Inc. (GES), the Attorney General and the Public Staff. PEC stated that Carolina Industrial Group for Fair Utility Rates I, II, and III (CIGFUR) did not have sufficient time to take a position prior to the filing of the Proposed Pro Rata Mechanism. PEC stated that ElectriCities of North Carolina, Inc. (ElectriCities), does not support the Proposed Pro Rata Mechanism as written.

On February 12, 2010, the Commission issued an Order allowing the Electric Suppliers to withdraw their requests in the Joint Motion that the Commission: (1) delay the poultry waste set-aside requirement of GS 62-133.8(f); (2) reduce the poultry waste set-aside requirement; and (3) declare that it is not in the public interest for the Electric Suppliers to purchase electricity from a renewable generation facility unless the proposed prices are fixed or contain reasonable price risk mitigation. The Commission further concluded that issuance of the joint RFP is reasonable as a means for the electric power suppliers to work together collectively to meet the swine waste resource set-aside requirement and approved its issuance for purposes of the state action immunity doctrine. Lastly, the Commission noted that the proposed pro rata allocation of the aggregate swine and poultry waste resource set-aside obligations has wide, but not unanimous support among the electric power suppliers, and allowed parties to file comments on this issue.

Comments were filed on February 26, 2010, by NCEMPA, NCMPA, the North Carolina Sustainable Energy Association (NCSEA), and the Public Works Commission of Fayetteville (FPWC). On March 5, 2010, NCSEA filed a Motion for Leave to File Supplemental Comments and Supplemental Comments.

COMMENTS BY THE PARTIES

In their joint comments, NCEMPA and NCMPA (jointly, the Power Agencies) state that they do not disagree that the Proposed Pro Rata Mechanism provides clarity not otherwise provided by the REPS legislation. However, the Power Agencies object to any amendment or rewriting of the swine and poultry waste set-aside requirements by the Commission. The Power Agencies note that, had the legislature intended for the swine and poultry waste set-aside requirements to apply individually to each electric power supplier, it could have omitted the phrase "in the aggregate" from these provisions as it did with the solar set-aside requirement. Moreover, argue the Power Agencies, G.S. 62-133.8(i)(2) cannot be read to authorize the Commission to rewrite or amend these provisions; such action is beyond the statutory authority granted to the Commission because it is an unconstitutional delegation of power by the legislature.

Notwithstanding these objections, the Power Agencies state that they will join in, and waive any objections to, the Proposed Pro Rata Mechanism if the Commission clarifies its holding in the May 7, 2009 Order on Duke Energy Carolinas, LLC, Motion for Clarification. In that Order, the Commission determined that the set-aside requirements have priority over the general REPS requirement where both cannot be met without exceeding the per-account cost cap established in G.S. 62-133.8(h) (Priority Holding). The Power Agencies seek clarification, as stated at page 3 of their filing, that this holding

> only applies when an electric power supplier is meeting its REPS obligations by complying with the general REPS percentage obligation, and that satisfaction of its general REPS percentage obligation is subject to the electric power supplier's satisfaction of the set-asides.

The Power Agencies further state:

> The Power Agencies, however, cannot join in the Proposed Pro Rata Mechanism if the Priority Holding is clarified to mean that an electric power supplier planning on satisfying its REPS obligations by meeting its cost cap must spend all of its cost cap dollars on the set-asides until the set-asides are satisfied before spending any of its cost cap dollars on those compliance methods listed under G.S. §§ 62-133.8(b)(2) and (c)(2), as applicable.

In their motion for clarification, the Power Agencies note that statutes should be construed <u>in pari materia</u> to harmonize and give effect to all provisions. <u>State ex rel Hunt v. North Carolina Reinsurance Facility</u>, 302 N.C. 274, 288, 275 S.E.2d 399, 405 (1981). In applying this rule of statutory construction, the Power Agencies argue, at page 12, as follows:

> Of course, as stated above by the North Carolina Supreme Court, in applying such a statutory construction mechanism, statutes <u>in pari materia</u> must be construed and harmonized to give effect to each. The application of the construction mechanism in this context leaves intact the clear intention of the REPS Legislation that the electric power suppliers have two separate means of complying with its REPS obligations: i) by meeting the general REPS percentage requirement (except that now in order to do so, the electric power supplier must fulfill its set-aside obligations first); or ii) by reaching the per-account cost cap. If the foregoing is the sole meaning of the Priority Holding, the Power Agencies agree that the Proposed Pro Rata Mechanism is necessary to quantify the obligations of the electric power suppliers under the swine and poultry waste set-asides, which quantification is necessary to read and interpret the general requirements of G.S. [62-]133.8(c)(2) and the specific set-aside obligations set forth in G.S. [62-]133.8(e) and (f) in harmony.
>
> The Power Agencies, however, are concerned that the Priority Holding in the Duke Order is susceptible to another interpretation, one that, if followed, would violate the above-discussed principles of statutory construction, by preventing all sections of the REPs Legislation from being read in harmony, and vitiating other compliance provisions in the REPS Legislation. It is this potential interpretation of the Priority Holding, when coupled with the Pro Rata Mechanism, that prevents the Power Agencies from joining in the Proposed Pro Rata Mechanism.

The Power Agencies further state, at pages 12 through 14, that they are concerned that the Priority Holding is susceptible to an overly broad interpretation (although such interpretation is not specifically stated in the Duke Order)

> that would require an electric power supplier, whose compliance plan indicates that compliance will result from reaching its cost cap (as opposed to meeting the percentage renewable energy generation requirements set forth in the statute, including the set-asides), to spend all of its cost cap dollars first on the solar, swine and poultry waste set-asides. Such a result would be contrary to a fundamental element of the principle of statutory construction discussed above that the statutes being construed must be <u>in pari materia</u> or deal with the same

> subject matter. ... The Priority Order cannot be interpreted as applying to the cost cap because the statutory provisions that establish it need not be reconciled with, or read or interpreted in the context of, meeting the percentage requirements, including the set-asides. The statutory provisions dealing with the percentage requirements and the statutory provisions establishing the cost cap are not in pari materia (and already can be read in harmony) because they relate to separate and distinct subject matters; it is not necessary to apply the Priority Holding to both, as no statutory construction is necessary. In addition, reading the Priority Order to apply to the cost cap would impose a condition on the cost cap that simply is not present in the statute and one that does not have to be implied to give the cost cap meaning.

The Power Agencies' fundamental concern is noted in their motion for clarification, at pages 14 through 15, as follows:

> Reading the Priority Holding in a manner that applies it to the cost cap also would vitiate certain compliance methods available to electric power suppliers by the REPS Legislation. G.S 62-133.8(c)(2) sets forth various ways in which a municipality or electric membership cooperative can meet the requirements of the REPs Legislation, including, but not limited to, reducing energy consumption by the use of demand-side management or energy efficiency measures. The current projections of one of the Power Agencies indicate that, through at least 2015, it will reach its cost cap by implementing compliance activities specifically permitted by G.S § 62-133.8(c)(2), none of which would include the set-asides. If the Priority Holding were interpreted to require that the cost cap be met first with dollars spent on the set-asides, municipalities and electric membership cooperatives would be prevented from utilizing the compliance methods set forth in G.S § 62-133.8(c)(2). Such a construction would not only vitiate those compliance methods by ignoring their presence in the statute, but also prevent all provisions of the statute from being construed and harmonized to give effect to each.
>
> In addition, such a reading of the Priority Holding makes absolutely no practical sense, and clearly is not a proper application of the statutory construction mechanism allowing specific statutes to act as exceptions to general statutes concerning similar situations. After the Commission determined, in the Priority Holding, that the set-asides were a prerequisite to fulfilling the general REPS percentage requirement, there was no ambiguity in the REPS Legislation created by any apparent conflict between the general REPS percentage requirement, the set-asides, or the cost cap. The plain language of the REPS Legislation had, at that point, been read by the Commission to establish a compliance scheme in which an electric power supplier's satisfaction of the general REPS percentage requirement and the set-aside requirements were one method of compliance, and an electric power supplier's meeting the cost cap was another method of compliance. The provisions were in harmony and made sense when read together.

> At that point, any use of the statutory construction mechanism was flawed because all three sets of provisions stood on their own and had meaning in the REPS Legislation without ambiguity. In sum, the Commission had no cause to use a statutory construction mechanism in such instance, and certainly could not use a statutory construction mechanism as a basis to place new conditions on one statute – the cost cap – that, in effect, render meaningless another set of statutory provisions – the general REPS requirements in G.S. §§ 62-133.8(b)(2) and (c)(2).

In its comments, FPWC does not take a position on the pro rata proposal, but requests that the Commission affirm the following principles in any order it issues regarding either the pro rata proposal or any other swine and poultry waste allocation methodology presented in this proceeding:

> (i) the allocation methodology for aggregate swine and poultry waste resource set-aside obligations that is approved or adopted by the Commission will not require an electric power supplier to exceed the annual cost caps set forth in N.C.G.S. §§ 62-133.8(h)(3) and (4); and (ii) the allocation methodology for aggregate swine and poultry waste resource set-aside obligations that is approved or adopted by the Commission will not grant the aggregate swine and poultry waste resource set-aside obligations a higher priority than the solar set-aside obligation set forth in N.C.G.S. § 62-133.8(d).

FPWC states that the parties supporting the pro rata proposal support these principles.

In its comments, NCSEA supports the proposed pro rata allocation, noting that it equitably allocates the burden of advancing the public benefit embodied in the set-aside requirements among the electric power suppliers. In its supplemental comments, at pages 2 through 3, NCSEA disagrees with the Power Agencies' interpretation of the REPS statute, stating:

> In its comments, the Power Agencies argue that one method for achieving compliance with the REPS law is to intentionally exceed the cost cap in G.S. § 62-133.8(h)(4). According to the Power Agencies, an electric power supplier may have a "compliance plan" that sets out to reach "its cost cap (as opposed to meeting the percentage renewable energy generation requirements set forth in the statute, including the set asides)." ... Clearly this interpretation of the law cannot be correct. While an electric power supplier may be deemed to be in compliance by reaching a cost cap, G.S. § 62-133.8(h)(3), it cannot set "exceeding the cost cap" as its REPS objective. Exceeding the cost cap without meeting the REPS requirements has to be viewed as a practical failure. A plan contemplating that result is inconsistent with the law and potentially will lead to reckless spending.
>
> The REPS Law makes clear what constitutes compliance and how compliance can be achieved. ... While Section 62-133.8(h)(3) provides that an electric power supplier will be "deemed" in compliance with the REPS law if total incremental costs for a year exceed the respective cost cap, exceeding the

cost cap without achieving the REPS requirements is nevertheless a failure to achieve compliance. The objective of the REPS Law is to achieve the REPS requirements in Sections 62-133.8(b) & (c). The goal is not to simply spend a certain amount of money on renewable energy or energy efficiency measures. Rather, the goal is to spend money in a way that will result in the REPS requirements being met. Compliance is meeting the requirements and a plan that focuses on how to exceed the cost cap, is no compliance plan at all.

DISCUSSION AND CONCLUSIONS

The Commission agrees with the Power Agencies that the General Assembly established an aggregate obligation for the swine and poultry waste set-aside requirements, different from the solar set-aside requirement. As the Commission stated in its May 7, 2009 Order, at page 7,

> by establishing an aggregate requirement for the swine and poultry waste resources, the General Assembly did not impose a specific requirement, pro rata or otherwise, on any individual electric power supplier. Rather, the electric power suppliers are charged with collectively meeting the aggregate requirement. ... The Commission, therefore, agrees with the Public Staff that the language of the swine and poultry waste set-aside provisions contemplate that the electric power suppliers may agree among themselves how to collectively satisfy the requirements of those subsections.

Such an arrangement, however, prior to February 5, 2010, has proven to be unworkable as no agreement had been reached among the electric power suppliers to allow these set-aside requirements to be met. The February 5, 2010 pro rata mechanism is one selected by most of the State's electric power suppliers and, therefore, represents their collective determination of how to meet the aggregate requirements. By approving this electric power supplier selected mechanism, the Commission agrees with this method of meeting the aggregate requirements. While the Commission would have preferred unanimous agreement among all electric power suppliers, Commission authorization over the objections of the Power Agencies does not constitute alteration of the legislatively enunciated aggregate requirements. The Commission, therefore, concludes that the Proposed Pro Rata Mechanism is a reasonable and appropriate means for the electric power suppliers to meet the aggregate swine and poultry waste set-aside obligations of G.S. 62-133.8(e) and (f).

In approving the proposed mechanism, the Commission is not amending the statute pursuant to G.S. 62-133.8(i)(2), but approving an electric power supplier selected means of determining compliance with the statute. Therefore, the Power Agencies' argument that the authority granted to the Commission by the legislature in G.S. 62-133.8(i)(2) is unconstitutional is moot. In any event, as the Commission stated in its May 7, 2009 Order, at page 8:

> First, an act of the General Assembly is presumed to be constitutional. State ex rel. Martin v. Preston, 325 N.C. 438, 448, 382 S.E.2d 473, 478 (1989). Second, it is not within the Commission's jurisdiction, as a quasi-judicial administrative agency, to rule on the constitutionality of a statute. Great Am. Ins. Co. v. Gold, 254 N.C. 168, 173, 118 S.E.2d 792 (1961).

With regard to the motion for clarification, the Commission cannot agree with the Power Agencies' interpretation of Senate Bill 3 and the Priority Holding in the May 7, 2009 Order. The Power Agencies request that the set-aside requirements only have priority over other means of complying with the general REPS requirement of Senate Bill 3 when the electric power supplier is meeting the general REPS percentage requirement, and not when the electric power supplier is limited by the per-account cost cap. However, if the electric power supplier were able to meet the general REPS percentage requirement, the question of priority would not be at issue. It is, in fact, only when the electric power supplier cannot meet the general REPS percentage requirement because of the per-account cost cap that the choice of the means of compliance becomes important. As the Commission stated in its May 7, 2009 Order, at page 5:

> As a part of compliance with the general REPS percentage requirement, the General Assembly set out three specific renewable energy resource percentage or energy requirements, the solar, swine waste, and poultry waste set-aside requirements.[1] After careful review, the Commission concludes that, as Fibrowatt argues, although it might result in less renewable energy generation offsetting conventional electric generation, the presence of the set-aside requirements demonstrates the General Assembly's intent that they should have priority over the general REPS requirement where both cannot be met without exceeding the per-account cost cap established in G.S. 62-133.8(h). This interpretation is consistent with the rule of statutory construction that provides that specific provisions of a statute should prevail over general provisions. State ex rel. Utils. Comm'n v. Lumbee River Elec. Membership Corp., 275 N.C. 250, 260, 166 S.E.2d 663 (1969). Except for the earlier date established for solar, however, there is no basis for giving one set-aside requirement priority over another if they cannot all be met without exceeding the cost cap. [Footnote in original.]

The Commission disagrees with the Power Agencies that the statutory provisions in Senate Bill 3 related to the general REPS percentage requirement and those related to the cost cap related to separate and distinct subject matters. An electric power supplier's obligation under the REPS section of Senate Bill 3 is to meet the general REPS percentage requirement stated in G.S. 62-133.8(b) or (c) and to meet the specific set-aside requirements set forth in subsections (d), (e) and (f). The set-aside requirements are independent and complementary obligations under Senate Bill 3; i.e., an electric power supplier cannot comply with Senate Bill 3 by meeting the general percentage requirement while ignoring the set-aside requirements. An electric power supplier's obligation is limited, however, by the per-account incremental cost cap set forth in subsection (h). As stated in that subsection, an electric power supplier may not recover from its customers an amount in excess of the per-account cost caps and shall be deemed to be in compliance with the REPS requirement if its incremental costs reach the cost cap. Thus, the cost cap does not relate to a separate and distinct subject matter, but is integral to the overall compliance requirement. As the Commission further stated in its May 7, 2009 Order, at page 8,

[1] Although an electric power supplier may comply with its REPS obligation either by meeting the percentage requirements set forth in the statute or by reaching the per-account cost cap, it cannot comply by meeting the general REPS percentage requirement without satisfying each of the set-aside requirements. The electric power supplier must acquire set-aside energy resources until it meets the set-aside requirements or reaches the per-account cost cap.

> in the REPS provisions of Senate Bill 3, the General Assembly crafted a complex arrangement of obligations, cost-containment provisions, and safety valves. In concluding that no set-aside requirement takes priority over another, it is possible that an electric power supplier may reach the cost cap established in G.S. 62-133.8(h) before it has met each of the set-aside requirements.

This statutory construction does not, as argued by the Power Agencies, "vitiate certain compliance methods available to electric power suppliers." The Power Agencies argue that, if they are required to give priority to the set-aside requirements and, in so doing, reach the incremental cost cap, they will be denied the opportunity to use other means to comply with the general REPS percentage requirement. However, if an electric power supplier reaches the incremental cost cap, it is no longer required to meet the general REPS percentage obligation and need not avail itself of any other compliance method. Thus, the Commission is not ignoring the presence of other compliance methods or preventing all provisions of the statute from being construed and harmonized, but giving effect to the General Assembly's intent in setting forth set-aside requirements in the statute. As reiterated above, quoting from the Commission's May 7, 2009 Order, at page 5,

> the presence of the set-aside requirements demonstrates the General Assembly's intent that they should have priority over the general REPS requirement where both cannot be met without exceeding the per-account cost cap established in G.S. 62-133.8(h).

On the one hand, the Power Agencies acknowledge in their motion for clarification, at page 14, that:

> After the Commission determined, in the Priority Holding, that the set-asides were a prerequisite to fulfilling the general REPS percentage requirement, there was no ambiguity in the REPS Legislation created by any apparent conflict between the general REPS percentage requirement, the set-asides, or the cost cap.

However, the Power Agencies further argue that they should be allowed to give priority to reducing energy consumption through the implementation of demand-side management (DSM) or energy efficiency (EE) measures pursuant to G.S. 62-133.8(c)(2)(b) over the set-aside requirements of subsections (d) through (f). The Power Agencies argue that an electric power supplier incurs incremental costs equal to the cost cap by the implementation of DSM or EE measures, it is deemed to be in compliance with the REPS provisions of Senate Bill 3 and has no obligation under the set-aside requirements.[1] The Commission disagrees with this interpretation of Senate Bill 3. For municipal utilities, purchasing renewable energy, renewable energy

[1] The Power Agencies' argument is based on the assumption that "incremental costs" incurred by municipal electric suppliers in implementing DSM and EE measures are costs limited for recovery by the cost cap provisions of Senate Bill 3. While this issue was discussed in Issue 32 of the Commission's February 29, 2008 Order Adopting Final Rules, Docket No. E-100, Sub 113, the Commission declined at that time to adopt a definition of "incremental costs" that is more restrictive than that provided in Senate Bill 3 or to prejudge any proposals for DSM/EE cost recovery. The Commission, therefore, notes that the Power Agencies' assumption has never been expressly addressed or adopted. The Commission determines that it can resolve the disputes raised by the Power Agencies currently at issue in this docket without addressing this assumption.

certificates (RECs) and energy savings from the implementation of DSM or EE measures are alternative methods of compliance with the general REPS percentage requirement. Just as renewable energy derived from the sun, swine waste and poultry waste have priority over renewable energy derived from other renewable energy resources, these set-aside requirements have priority over other methods of compliance with the general REPS percentage requirement where the general requirement cannot be met without exceeding the incremental cost cap. This does not mean that an electric power supplier that expects to incur incremental costs equal to the cost cap should not implement DSM or EE measures with no incremental cost, i.e., that result in energy savings at a cost below the utility's avoided cost. The Commission takes judicial notice of the EE potential evaluated in connection with the 2006 study by La Capra Associates,[1] the integrated resource plans submitted by the electric public utilities,[2] and other recent studies that indicate that substantial energy savings may be realized through the implementation of DSM or EE measures at a cost less than the average avoided costs in North Carolina.[3] Nevertheless, the Commission reiterates its earlier holding that the set-aside requirements, as demonstrated by their inclusion in the legislation, have priority over other methods of compliance with the general REPS percentage obligation where the general REPS percentage obligation cannot be met because of the incremental cost cap.

Lastly, the Commission agrees with FPWC that approval of the Proposed Pro Rata Mechanism will not require an electric power supplier to exceed the incremental cost cap and will not grant the swine and poultry waste set-aside requirements a higher priority than the solar set-aside requirement. As the Commission stated in its May 7, 2009 Order, at page 5,

> Although no set-aside requirement has priority over another, the Commission does not agree with Fibrowatt that an electric power supplier should be required to obtain some of each of the set-aside resources if it cannot satisfy all of the set-aside requirements without exceeding the cost cap. Electric power suppliers may exercise their reasonable judgment in determining which renewable energy or RECs to acquire with the funds available under the cost cap.

IT IS, THEREFORE, ORDERED that the proposed pro rata mechanism of allocating the statewide aggregate swine and poultry waste set-aside requirements among the State's electric power suppliers filed on February 5, 2010, shall be, and hereby is, approved as a means of determining compliance by any electric power supplier with the REPS provisions of Senate Bill 3.

ISSUED BY ORDER OF THE COMMISSION.
This the 31st day of March, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Patricia Swenson, Deputy Clerk

Kc033110.01

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[1] Analysis of a Renewable Portfolio Standard for the State of North Carolina, La Capra Associates, December 2006; A Study of the Feasibility of Energy Efficiency as an Eligible Resource as Part of a Renewable Portfolio Standard for the State of North Carolina, GDS Associates, Inc., December 2006.

[2] See, e.g., Docket No. E-100, Subs 118 and 124.

[3] See, e.g., North Carolina's Energy Future: Electricity, Water, and Transportation Efficiency, American Council for an Energy-Efficient Economy, March 2010.

DOCKET NO. E-100, SUB 113

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Rulemaking Proceeding to Implement Session Law 2007-397	))))	ORDER ON JOINT MOTION TO APPROVE COLLABORATIVE ACTIVITY REGARDING POULTRY WASTE SET-ASIDE REQUIREMENT

BY THE COMMISSION: On May 24, 2010, Progress Energy Carolinas, Inc.; Dominion North Carolina Power; North Carolina Electric Membership Corporation; North Carolina Eastern Municipal Power Agency; North Carolina Municipal Power Agency Number 1; EnergyUnited Electric Membership Corporation; Halifax Electric Membership Corporation; GreenCo Solutions Inc.; and Fayetteville Public Works Commission (jointly, the Movants) filed a Joint Motion requesting Commission approval to jointly procure and/or engage in collaborative efforts to obtain renewable energy or renewable energy certificates (RECs) to satisfy the poultry waste resource set-aside requirement of the North Carolina Renewable Energy and Energy Efficiency Portfolio Standard (REPS), G.S. 62-133.8(f). In support of the Joint Motion, the Movants state that, since the Commission's March 31, 2010 approval of the pro rata mechanism for allocating the statewide aggregate swine and poultry waste set-aside requirements, they have determined that the most efficient, equitable and productive means for each to procure their pro rata allocated share of the poultry waste set-aside requirement is to collaborate in the evaluation of the various poultry waste generation technologies and the joint procurement of poultry waste generated renewable energy. As provided in the Commission's May 7, 2009 order in this docket, the Movants seek Commission approval to (a) share the poultry waste generation bids they have received with the other Movants; (b) enter into joint agreements with poultry waste generators to purchase renewable energy and RECs; and (c) otherwise engage in collaborative activity to comply with the poultry waste set-aside requirement. The Movants argue that such collaboration and joint procurement will provide the following benefits to the state and the Movants: (1) each of the Movants will have an equal opportunity to procure poultry waste generated renewable energy from the most cost-effective resources available; (2) each of the Movants will avoid having to conduct individual poultry waste generation solicitations; and (3) for those Movants whose individual pro rata obligations are not sufficiently large to justify and support a poultry waste generating facility, they may combine their respective poultry waste obligations to create a need of sufficient size to justify an entire poultry waste facility.

In its February 12, 2010 Order in this docket, the Commission reiterated its support for such collaborative efforts and continued to urge all electric power suppliers to work together to collectively meet the statewide aggregate poultry waste set-aside obligation and comply with G.S. 62-133.8(f). The Commission further concluded in that order that issuance of a proposed joint RFP for energy derived from swine waste and swine waste RECs was reasonable as a means for the electric power suppliers to work together collectively to meet the swine waste set-aside requirement and approved its issuance for purposes of the state action immunity doctrine.

After careful consideration, the Commission similarly concludes that the collaborative efforts proposed in the Joint Motion are reasonable as a means for the Movants to work together collectively to meet the poultry waste set-aside requirement and approves such efforts for purposes of the state action immunity doctrine. The Commission reserves the right, however, to resolve any future issues or differences that may arise among potential suppliers of poultry waste derived energy or RECs and the Movants. In addition, the Commission states that its approval does not constitute approval of any costs for ratemaking purposes, and this order is without prejudice of any party to take issue with the ratemaking treatment of any costs in a future proceeding.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 25th day of June, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Commissioner ToNola D. Brown-Bland did not participate in this decision.

SW062510.01

DOCKET NO. E-100, SUB 113

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Rulemaking Proceeding to Implement	)	ORDER DENYING PETITION
Session Law 2007-397	)	TO MODIFY POULTRY WASTE
	)	SET-ASIDE REQUIREMENT

BY THE COMMISSION: On August 10, 2010, Peregrine Biomass Development Company, LLC (Peregrine), filed a Petition requesting that the Commission exercise its discretionary authority pursuant to G.S. 62-133.8(i)(2) (the off-ramp) to allow renewable energy certificates (RECs) associated with the thermal energy output of a combined heat and power (CHP) facility which uses poultry waste as a fuel to count toward the poultry waste set-aside requirement of G.S. 62-133.8(f).

On August 25, 2010, the Commission issued an Order Requesting Comments on the Use of Thermal RECs to Satisfy Poultry Waste Set-Aside Requirement in this docket. In its August 25, 2010 Order, the Commission noted that, in Docket No. SP-578, Sub 0, Green Energy Solutions NV, Inc. (GES), the owner of another CHP facility that uses, in part, poultry waste as fuel, filed a Motion for Clarification seeking an interpretation by the Commission that the statute allows the use of both RECs associated with electric power and thermal energy to meet the poultry waste set-aside requirement. The Public Staff, in its comments, argued that G.S. 62-133.8(f) only allows electric power suppliers to claim REPS credit against their poultry waste set-aside requirements for the electric power (but not the thermal energy) produced by a generating station which uses poultry waste. As a result of the Public Staff's comments, GES withdrew its Motion. In its August 25, 2010 Order, the Commission directed the parties to file comments on both the issue raised by Peregrine, whether the Commission should invoke the off-ramp to allow thermal RECs to be used to satisfy the poultry waste set-aside requirement, and the issue originally raised by GES, whether it is necessary to invoke the off-ramp to allow thermal RECs to be used to satisfy the poultry waste set-aside requirement.

Progress Energy Carolinas, Inc. (PEC); GreenCo Solutions, Inc. (GreenCo); and the North Carolina Poultry Federation (NCPF) filed letters in support of Peregrine's Petition before the Commission's August 25, 2010 Order was issued. Comments were filed by the following parties in response to the Commission's August 25, 2010 Order: Peregrine, GES, Duke Energy Carolinas, LLC (Duke); North Carolina Municipal Power Agency No. 1 and North Carolina Eastern Municipal Power Agency (collectively, Power Agencies); ElectriCities of North Carolina, Inc. (ElectriCities); Fayetteville Public Works Commission (FPWC); FLS Energy, Inc. (FLS); Fibrowatt, LLC (Fibrowatt); Organic Recycling Systems, Inc. (ORS); Weyerhauser; and the Public Staff. The comments filed by Daren Bakst and KapStone Kraft Paper Corporation (KapStone), neither of which have intervened as parties in this proceeding, shall be considered as consumer statements of position. Reply comments were filed by Peregrine; PEC, Power Agencies, ElectriCities, and GreenCo, jointly; North Carolina Sustainable Energy Association (NCSEA); and the Public Staff.

POSITION OF THE PARTIES

Duke, PEC, GreenCo, FPWC, FLS, ORS and NCPF

Duke, PEC, GreenCo, FPWC, FLS, ORS and NCPF all support Peregrine's Petition and argue that it is in the public interest for the Commission to invoke the off-ramp to allow thermal RECs to meet the poultry waste set-aside requirement, G.S. 62-133.8(f). Several parties urged the Commission to similarly modify the swine waste set-aside provision, G.S. 62-133.8(e), which is worded nearly identical, in relevant part, to the poultry waste set-aside provision.

Duke, for example, argues in its comments that allowing RECs associated with the thermal energy output of a poultry waste fueled CHP facility is in the public interest and will benefit the retail customers of the State by providing a cost-effective option for electric power suppliers to use for compliance with the poultry waste set-aside requirement. Duke agrees with the Public Staff's earlier comments that the statute does not currently permit the use of RECs associated with thermal energy for compliance with the poultry waste set-aside requirement. Thus, for the Commission to allow thermal energy RECs to meet the poultry waste set-aside requirement, it must invoke the off-ramp provision of Senate Bill 3 and the Commission's rules. Duke argues that the applicable standard for review of Peregrine's application under Senate Bill 3 and the Commission's rules is whether the requested modification of the poultry waste set-aside provision is "in the public interest." Since Peregrine is not an "electric power supplier," the specific requirement relating to a demonstration of "reasonable efforts to comply" do not apply to Peregrine. Duke believes that Peregrine's requested modification is in the public interest because the addition of thermal RECs to the portfolio of qualifying resources for the poultry waste set-aside requirement will serve to broaden options for the electric power suppliers and provide a more cost-effective compliance resource for this set-aside requirement, thereby benefitting retail customers.

In their joint reply comments, PEC, Power Agencies, ElectriCities and GreenCo offer several other justifications in support of Peregrine's Petition: (1) that the use of steam is very efficient, and to not allow thermal RECs to satisfy the set-aside requirements is essentially wasting renewable energy; (2) that, because the number of potential generators is limited, allowing generators of thermal RECs to compete will enhance the market and create additional opportunities to satisfy the set-aside requirements; and (3) the more technologies available to meet the set-aside requirements will result in greater opportunities for electric power suppliers to meet the requirements and greater price competition.

Power Agencies and ElectriCities

In their comments, Power Agencies and ElectriCities argue that the Commission, in its January 20, 2010 Order accepting registration of GES's facility, has already determined that the statute allows the use of thermal RECs to satisfy the poultry waste set-aside requirement:

> The Commission would not require GES to regularly provide data to the REC tracking system regarding "qualifying thermal energy generation data" and the percent of those "energy streams" that is ultimately derived from poultry waste versus other biomass materials unless the "useful" thermal energy used to heat the Collins Chick Farm is eligible to meet the poultry waste set-aside and produce poultry waste RECs.

Nevertheless, Power Agencies and ElectriCities support the Petition filed by Peregrine. The use of the off-ramp is in the public interest because to not do so will inhibit the development of a robust, competitive poultry waste generating industry and result in unnecessarily high costs for REPS compliance that will ultimately be paid for by North Carolina ratepayers.

Weyerhauser and KapStone

In their comments, Weyerhause and KapStone also supported Peregrine's Petition, each stating an interest in developing CHP at their plant. Weyerhauser argues that the REPS "should embrace the increased efficiency of CHP facilities by recognizing the useful thermal energy derived from such facilities" and that low-cost, reliable steam generated from such a facility could help its mills be more competitive. KapStone similarly states that a competitively priced reliable source of steam will help it remain economically viable in a very competitive business environment, and argues that "without the useful thermal energy counting toward the poultry waste set-aside requirement, the electric suppliers will not pay a price for the renewable attributes that will support these type projects."

Fibrowatt

In its comments, Fibrowatt opposes Peregrine's request, arguing that it will further delay the effort to comply with the poultry waste set-aside requirement. Fibrowatt agrees with the Public Staff that the statute allows only "electric power sold to retail electric customers" to satisfy the poultry waste set-aside requirement. It disagrees with Peregrine that a modification is necessary to allow the development of a robust, competitive poultry waste generating industry or that without thermal energy credits the poultry waste generating industry in North Carolina would be expensive and non-competitive, stating that "[t]here is absolutely no evidence to support this, and much of the data in this regard is currently the subject of private commercial discussions." Fibrowatt argues that there are ample competitive, affordable proposals to meet the poultry waste set-aside requirement currently before the electric power suppliers in North Carolina that can meet the poultry waste set-aside requirement without the requested change of law. As evidence of this, Fibrowatt notes that the electric power suppliers dropped their August 2009 Joint Motion to delay and reduce the poultry waste set-aside requirement:

> Serious and advanced discussions are ongoing between the electric suppliers and several other providers of poultry waste generated power. The parties who have labored to form these contracts have done so on the belief that the rules would not change at the last minute.

<u>Bakst and NCSEA</u>

In his comments, Bakst agrees with the Public Staff that the statute does not allow the use of thermal RECs to satisfy the poultry waste set-aside requirement: "The legislature made a choice, right or wrong, to exclude thermal energy to meet the poultry set-aside. The express language is not in dispute." Bakst further opposes Peregrine's Petition to alter the set-aside provision on the basis that the Commission has limited authority under the off-ramp provision and that such authority is insufficient to allow the Commission to grant the Petition. Bakst notes that the off-ramp provision only allows the Commission to "modify or delay" certain provisions of the statute. In analyzing the word "modify," Bakst concludes that the Commission has the authority to make the requirements of Senate Bill 3 "less extreme" if compliance is not feasible, but that the Commission cannot "add new language to the law or make its own substantive policy decisions":

> The legislature did not use the word "change" or "revise" in the off-ramp provision. It chose "modify" because it envisioned the Commission needing to make slight alterations to <u>existing</u> requirements in the law. If the Commission makes a policy decision by completely changing the statute as is being requested, the Commission would be ignoring the <u>express</u> will of the legislature and replacing it with its own views. To add thermal energy is to create new language that is in no way connected to the express language and intent of the provision being modified. ... Creating new language out of whole cloth, without being constrained by the statutory provision being modified, would give the Commission carte blanche to pass its own legislation. ... Peregrine's arguments regarding the public interest may be compelling. However, the legislature has made a choice not to include thermal energy. If Peregrine seeks a change, it should go to the legislature and convince them to change the law. It is not the Commission's role to do the legislature's job, as Peregrine would like it to do. [Emphasis in original.]

NCSEA, in its reply comments, echoes Bakst's concerns that the modification sought violates the doctrine of separation of powers. While NCSEA does not oppose Peregrine's substantive proposal, it argues that Peregrine's request must be denied. NCSEA argues that Peregrine's request to the Commission is a broad, substantive change:

> In every sense, the change requested by Peregrine would be an amendment to the REPS Law, not just the exercise of enforcement discretion. If the off-ramp provision were to operate so broadly, it would put the Commission in the place of the General Assembly, vitiate the separation of powers doctrine and violate the federal and state Constitutions. The executive branch executes and administers the law and has broad enforcement discretion; it does not enact, amend or repeal laws. Thus, the off-ramp allows the Commission to address compliance by delaying compliance dates or modifying compliance targets; it does not allow the Commission to enact a whole new method of compliance. That is precisely what Peregrine is asking the Commission to do. If the changes Peregrine wants are beneficial and promote the public policy, the appropriate venue for making that correction or change is the General Assembly.

Peregrine

In its Petition, Peregrine argued that, while the Public Staff's position in the GES matter that thermal RECs may not be used to meet the poultry waste set-aside requirement is not unreasonable, it will inhibit the development of a robust, competitive poultry waste generating industry and will result in unnecessarily high costs for REPS compliance to both the electric power suppliers and their customers. Peregrine further argued that the current opportunity for the development of poultry waste electric-only power generation is, essentially, a very narrow and limited marketplace. As long as this remains the case, development of efficient, economical, competitive poultry waste generation will be stifled. Use of the off-ramp provision by the Commission to encourage renewable energy development and competition by allowing the poultry waste set-aside provision to recognize both the useful thermal and electric energy is in the public interest and ought to be approved.

In its initial comments, Peregrine disagrees with the Public Staff and argues that the language of the poultry waste set-aside provision only requires that a specific resource – poultry waste – be used to meet the set-aside requirement, not that only electric power, a means of compliance, may be used to meet the requirement. The Commission should resolve the issue in this proceeding by clarifying that the poultry waste set-aside provision allows the use of thermal RECs rather than by invoking the off-ramp. However, should the Commission determine that the use of thermal RECs cannot be accomplished without using the off-ramp, then Peregrine requests that the Commission do so as quickly as possible.

In its reply comments, Peregrine notes that most of the comments received strongly support its Petition. Only the comments of Fibrowatt and Bakst oppose Peregrine's Petition. Peregrine argues that "modify" should not be interpreted as Bakst argues; rather, the delegation of authority in the off-ramp provision allows the Commission

> to "fine tune" Senate Bill 3 so that it would work to achieve the best methodologies for obtaining the policy goals specified by the General Assembly. Neither Peregrine nor any other party is suggesting that the Commission change the overall REPS goals of the statute. To the contrary, Peregrine and its supporters are simply urging the Commission to take steps which will allow the statute to work as the General Assembly intended.

Peregrine further disagrees with Fibrowatt's assertions and challenges Fibrowatt's motives as a high-cost supplier of poultry waste derived energy. Peregrine notes that months of negotiations have resulted in no contract between Fibrowatt and the State's electric power suppliers because of Fibrowatt's "highly elevated costs. ... It is the Fibrowatt ox which is being gored; it is not surprising that they are opposed."

Public Staff

In its comments, the Public Staff supports Peregrine's Petition to modify the poultry waste set-aside requirement: "By exercising its off-ramp authority as Peregrine has proposed, the Commission will facilitate the efforts of the State's electric power suppliers to satisfy the poultry waste set-aside at a reasonable cost." The Public Staff reiterated its position that the current provision does not allow the use of thermal RECs, but agreed with Peregrine that the language is too restrictive, stating:

> [It] would be desirable if facilities that generate electricity from poultry litter could use their waste heat to earn thermal RECs that are eligible for [sic] meet the poultry waste set-aside. However, in the Public Staff's view, the best way to achieve this result is by modifying the provisions of subsection (f) pursuant to the off-ramp, rather than by adopting a strained interpretation of the existing language that could be reversed on appeal.

Thus, for the reason advanced by Peregrine, the Public Staff strongly supports Peregrine's Petition. With regard to procedure, the Public Staff states that Peregrine, which is not an electric power supplier, is not required to demonstrate the reasonableness of the electric power suppliers' efforts to comply with the statute. The Public Staff states that Peregrine's verified Petition provides a prima facie demonstration of the need for a modification of the poultry waste set-aside on a statewide basis. There is no need for any further demonstration that a modification is needed by any specific supplier or group of suppliers. Lastly, the Public Staff notes that the off-ramp

> constitutes an unusual delegation of legislative authority (with appropriate limitations and guidelines) to an administrative agency. As such, it reflects the General Assembly's confidence in the Commission. The Commission should not be hesitant to exercise the authority granted by subdivision (i)(2), but it should, and undoubtedly will, conduct this and other off-ramp proceedings with great care, ensuring that interested parties have the opportunity to present all relevant facts and put forth all their arguments for and against the proposed modification.

In its reply comments, the Public Staff disagrees with the comments of Fibrowatt and Bakst. First, the Public Staff disagrees that a modification will result in delay; however, even if it does, it is outweighed by a reduction in the cost of compliance with the set-aside requirement. Second, using its own analysis of the word "modify," the Public Staff disagrees with Bakst's contention that the only allowable modifications under the off-ramp are those which narrow, rather than expand, a statutory provision. The Public Staff further disagrees with Bakst that the off-ramp is an unlawful delegation of legislative power because the Commission is provided with adequate standards to govern its decisions – that any modification be "in the public interest."

DISCUSSION AND CONCLUSIONS

The Commission agrees with the Public Staff and others that thermal RECs may not be used to meet the swine and poultry waste set-aside requirements, as written. G.S. 62-133.8(f) provides, in pertinent part, as follows:

> For calendar year 2014 and each calendar year thereafter, at least 900,000 megawatt hours of the total electric power sold to retail electric customers in the State shall be supplied, or contracted for supply in each year, by poultry waste combined with wood shavings, straw, rice hulls, or other bedding material.

The language of this provision stands in stark contrast with that of G.S. 62-133.8(d), the solar set-aside, which provides, in pertinent part, as follows:

> For calendar year 2018 and for each calendar year thereafter, at least two-tenths of one percent (0.2%) of the total electric power in kilowatt hours sold to retail electric customers in the State, <u>or an equivalent amount of energy</u>, shall be supplied by a combination of new solar electric facilities <u>and new metered solar thermal energy facilities</u>.... [Emphasis added.]

Thus, the General Assembly explicitly included thermal RECs for compliance with the solar set-aside requirement, and knew how to do so had it wanted to allow useful, measurable thermal energy derived from poultry waste to satisfy the set-aside requirement. In addition, the General Assembly drew a distinction between electric power generated by renewable energy resources, on the one hand, and useful, measurable thermal energy generated by renewable energy resources, on the other, in at least two other sections of G.S. 62-133.8. For example, in G.S. 62-133.8(a)(7), the General Assembly defined a "renewable energy facility" as one that either (a) generates electric power by use of a renewable energy resource or (b) generates useful, measurable thermal energy by the use of a renewable energy resource, including solar thermal and CHP. In addition, in G.S. 62-133.8(a)(8), the legislature defined a "renewable energy resource" as, among other things, "waste heat derived from a renewable energy resource and used to produce electricity or useful, measurable thermal energy." Thus, the General Assembly distinguished between electric power produced by a renewable energy resource and thermal energy produced by a renewable energy resource, and it did not include both types in the poultry waste set-aside provision as it did in the solar set-aside provision. The same reasoning also applies to the swine waste set-aside provision, G.S. 62-133.8(e). The swine and poultry waste set-aside provisions do not contain language similar to that of the solar set-aside provision; they only refer to "electric power." The statute allows CHP facilities to qualify as renewable energy facilities or new renewable energy facilities and earn RECs for the waste heat used to produce "useful, measurable thermal or mechanical energy at a retail electric customer's facility" to satisfy the general REPS requirements. However, while supporting CHP and recognizing the increased efficiencies it represents, the Commission concludes that thermal RECs generated by a CHP facility may not be used to satisfy the swine or poultry waste set-aside requirements of

G.S. 62-133.8(e) and (f). RECs may satisfy the swine and poultry waste set-aside requirements only if they result from the actual generation of electric power from swine or poultry waste. Nothing in the Commission's rules or its January 20, 2010 Order in Docket No. SP-578, Sub 0 accepting registration of GES's facility specifically addresses this issue or is inconsistent with this conclusion.

Therefore, G.S. 62-133.8(f) would have to be modified pursuant to the off-ramp in order to allow RECs associated with the thermal energy output of a CHP facility which uses poultry waste as a fuel to satisfy the poultry waste set-aside requirement. The Commission is aware of the exceptional nature of the off-ramp provision and the authority delegated to it by the General Assembly in the implementation of the REPS requirements of Senate Bill 3. Although the Commission is not persuaded that its authority under the off-ramp is as limited as that suggested by Bakst, it believes that the off-ramp should be narrowly construed and will exercise its authority under the off-ramp sparingly.

Notwithstanding the strong support for Peregrine's Petition in the comments filed by the parties in this proceeding, the Commission concludes that good cause has not been demonstrated to invoke its discretionary authority pursuant to the off-ramp provision to modify the poultry waste set-aside provision as requested by Peregrine. In this case, the State's electric power suppliers have recently issued a request for proposals (RFP) for poultry waste derived energy to satisfy the set-aside requirement and are negotiating with a number of developers. In their recently filed REPS compliance plans, in Docket No. E-100, Sub 128, the electric power suppliers indicated that they believe the amount of poultry waste energy proposed in response to the RFP will be sufficient to allow them to meet the set-aside requirement. The Commission, therefore, will not modify the poultry waste set-aside provision to broaden the means of compliance in the absence of stronger evidence that compliance with the statute, as written, is not feasible.

The fact that the electric power suppliers have not yet been able to finalize an agreement with Fibrowatt does not demonstrate that they will be unable to meet the requirements set forth in the statute, as argued by some parties in their comments. The electric power suppliers previously filed and withdrew a request to modify and delay the requirements of the poultry waste set-aside provision, and they may reassert such a request in the future if compliance does not appear possible despite reasonable efforts by the electric power suppliers. Even if the Commission were willing to invoke the off-ramp to modify the poultry waste set-aside provision because of the difficulty in obtaining sufficient energy derived from poultry waste resources, it is premature to do so now given that compliance with the poultry waste set-aside provision by the electric power suppliers is not required until 2012. Alternatively, as suggested by Bakst and NCSEA, Peregrine and its supporters should look to the General Assembly to modify the statute to allow the use of thermal RECs to meet the swine and poultry waste set-aside requirements.

IT IS, THEREFORE, ORDERED that Peregrine's August 10, 2010 Petition requesting that the Commission modify the poultry waste set-aside requirement shall be, and hereby is, denied.

ISSUED BY ORDER OF THE COMMISSION.
This the 8th day of October, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Commissioner Lorinzo L. Joyner did not participate in this decision.

Sw100810.01

DOCKET NO. E-100, SUB 113

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Rulemaking Proceeding to Implement	)	ORDER ON JOINT MOTION
Session Law 2007-397	)	FOR DECLARATORY RULING
	)	REGARDING COST RECOVERY

BY THE COMMISSION: A Joint Motion was filed in this docket on September 14, 2010, by Progress Energy Carolinas, Inc. (PEC); Duke Energy Carolinas, LLC (Duke); Dominion North Carolina Power; North Carolina Electric Membership Corporation; GreenCo Solutions, Inc.; North Carolina Eastern Municipal Power Agency; and North Carolina Municipal Power Agency No. 1 (collectively, Movants). Movants seek a declaratory ruling from the Commission that an electric public utility is entitled to recover through G.S. 62-133.2(a1)(6) the total delivered costs of all megawatt-hours purchased from renewable energy facilities and new renewable energy facilities as defined by G.S. 62-133.8, regardless of whether the electric public utility purchases the renewable energy certificate (REC) associated with the renewable energy.

The Commission issued an Order on September 16, 2010, allowing parties an opportunity to file comments and reply comments. Comments have been filed by Movants; Carolina Utility Customers Association, Inc. (CUCA); Green Energy Solutions NV, Inc. (GES); and the Public Staff.

As background, the Commission notes that G.S. 62-133.8 imposes various obligations on electric power suppliers, i.e., electric public utilities, electric membership corporations and municipalities, under the Renewable Energy and Energy Efficiency Portfolio Standard (REPS), G.S. 62-133.8(b) through (f). Two of these obligations are for the purchase of renewable energy generated by the use of swine and poultry waste resources, and these obligations are each stated in terms of an aggregate requirement for the entire State. G.S. 62-133.8(e) and (f). In its Order on Pro Rata Allocation of Aggregate Swine and Poultry Waste Set-aside Requirements and Motion for Clarification issued March 31, 2010, in Docket No. E-100, Sub 113, the Commission approved a pro rata mechanism proposed by the electric power suppliers as a means of determining compliance with the statewide aggregate swine and poultry waste set-aside requirements. The Commission subsequently approved collaborative efforts by most of the electric power suppliers to meet these statewide aggregate requirements. Order on Withdrawal of Joint Motion, Issuance of Joint Request for Proposals, and Allocation of Swine Waste Set-aside Requirement, Docket No. E-100, Sub 113 (Feb. 12, 2010); Order on Joint Motion to Approve Collaborative Activity Regarding Poultry Waste Set-aside Requirement, Docket No. E-100, Sub 113 (June 25, 2010). Although most of the energy generated from swine waste, for example, will be purchased by PEC pursuant to these approved collaborative efforts because a majority of the swine farms in North Carolina are located in the Eastern part of the State in PEC's assigned service territory, many of the RECs associated with that energy will likely be purchased by Duke and other electric power suppliers in the State to meet their pro rata allocation of the statewide aggregate set-aside requirement.

The Joint Motion presents an issue as to the cost recovery by an electric public utility for such purchases of energy from swine and poultry waste generators (which will also likely be qualifying facilities as defined in the Public Utility Regulatory Policies Act of 1978 (PURPA)) where the REC associated with the energy is being purchased by another North Carolina electric power supplier for REPS compliance. Movants seek a declaratory ruling that a public utility will be able to recover all of the costs incurred for such power purchases through G.S. 62-133.2(a1)(6) of the fuel adjustment clause statute.

The relevant statutory provisions are as follows:

G.S. 62-133.8(h)(4) allows electric power suppliers to recover through an annual REPS rider the incremental costs incurred to comply with the REPS requirements. The incremental costs recoverable through this REPS rider include "all reasonable and prudent costs incurred by an electric power supplier to 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." G.S. 62-133.8(h)(1)a. The cost of purchasing a REC is an example of such an incremental cost. These costs are subject to the total cost cap of G.S. 62-133.8(h)(3) and the per-account caps of G.S. 62-133.8(h)(4).

G.S. 62-133.2(a) of the fuel adjustment statute provides that the Commission

> shall permit an electric public utility that generates electric power by fossil fuel or nuclear fuel to charge an increment or decrement as a rider to its rates for changes in the cost of fuel and fuel-related costs used in providing its North Carolina retail customers with electricity from the cost of fuel and fuel-related costs established in the electric public utility's previous general rate case on the basis of cost per kilowatt-hour.

G.S. 62-133.2(a1) defines the term "cost of fuel and fuel-related costs," and it includes the following subsections:

(5) The capacity costs associated with all purchases of electric power from qualifying cogeneration facilities and qualifying small power production facilities, as defined in 16 U.S.C. § 796, that are subject to economic dispatch by the electric public utility.

(6) Except for those costs recovered pursuant to G.S. 62-133.8(h), the total delivered costs of all purchases of power from renewable energy facilities and new renewable energy facilities pursuant to G.S. 62-133.8 or to comply with any federal mandate that is similar to the requirements of subsections (b), (c), (d), (e), and (f) of G.S. 62-133.8.

(7) The fuel cost component of other purchased power.

Comments of the Parties

In their initial comments, Movants argue that the fuel adjustment clause statute, G.S. 62-133.2, and the REPS statute, G.S. 62-133.8, together provide for full recovery of costs incurred by an electric public utility to purchase power from renewable energy facilities and new renewable energy facilities. The "incremental costs," including the cost of RECs, are recovered through the REPS rider; the remaining costs are recovered through the fuel adjustment clause rider. In this case, the RECs associated with the swine and poultry waste energy are being allocated to other electric power suppliers to meet the statewide aggregate set-aside requirement, so none of the costs incurred by the utility are "incremental costs" recoverable pursuant to G.S. 62-133.8. Therefore, argue the Movants, the costs the utility incurs in purchasing the renewable energy are recoverable through the fuel adjustment clause rider pursuant to G.S. 62-133.2.

In its initial comments, the Public Staff states that it supports the pro rata allocation of the statewide poultry and swine waste set-aside and is sympathetic to Movants' concerns, but that it opposes the request on the grounds that G.S. 62-133.2(a1)(6) does not authorize recovery through the fuel adjustment clause statute of the total delivered costs of a utility's purchases of energy from renewable energy facilities and new renewable energy facilities when the utility does not purchase the associated REC. The Public Staff interprets the phrase "purchases of power from renewable energy facilities and new renewable energy facilities pursuant to G.S. 62-133.8" as limited to purchases to meet the purchaser's own REPS obligation, i.e., purchases bundled with the associated REC.

> While the megawatt-hours purchased may be used to serve the electric public utility's customers, the total delivered costs of those purchases would not have been incurred by the electric public utility pursuant to G.S. 62-133.8 absent the REPS obligations of other electric power suppliers. These costs might have been incurred by the electric public utility pursuant to its PURPA obligations, but in that case, their recovery would be governed by subsections (5) and (7) of G.S. 62-133.2(a1), not subsection (6). [Emphasis in original.]

Alternatively, states the Public Staff, if any relief is allowed, that relief should be limited to only those purchases made as part of a collaborative effort by electric power suppliers to meet the statewide aggregate swine and poultry waste set-aside requirements. The Public Staff suggests that there are alternative ways to deal with Movants' concerns – such as wheeling the energy to the suppliers that purchase the RECs or a "virtual pooling mechanism" – that would both allow cost recovery and comply with the General Statutes.

CUCA also opposes the request. CUCA states that it has consistently argued that the fuel adjustment clause statute should be strictly limited, and that this request would set a bad precedent for expanding the scope of cost recovery through fuel adjustment clause proceedings. CUCA states that the motion is premature and that it would be better for the General Assembly to clarify the matter.

In its comments, GES states that it has submitted proposals to each of the Movants, wherein it proposes to sell to these utilities electricity at their respective avoided costs, which the utilities are permitted to recover pursuant to G.S. 62-133.2(a1)(6). Separately, GES will be offering for sale, at the prevailing market rate, the RECs associated with the generation of renewable energy that is produced at GES's facilities.

In their reply comments, Movants reiterate that, since a utility purchasing energy without the associated RECs cannot recover any of its costs through the REPS rider, "all of the purchased power costs are to be recovered through the fuel and fuel-related costs rider." They argue that the Public Staff fails to appreciate the unique situation posed by the REPS statewide aggregate swine and poultry waste set-aside obligations. Absent the approved pro rata allocation mechanism, all of the renewable energy purchased under the statewide aggregate obligation would have been purchased pursuant to G.S. 62-133.8. "The fact that a simple administrative measure was necessary to enable an equitable division of the statewide aggregate obligation should not result in either an increase in costs to North Carolina customers or an unfair imposition of potentially stranded costs to any one utility." Movants argue that the General Assembly's goal was to allow recovery of all costs that suppliers incur in complying with the REPS standards and that the Public Staff's position would leave some costs "trapped and unrecovered." Movants state that the alternatives suggested by the Public Staff present "knotty questions and strained interpretations" that can be avoided by allowing the declaratory ruling as requested.

In its reply comments, the Public Staff argues that Movants' interpretation of G.S. 62-133.2(a1)(6) is not only contrary to the purpose and intent of the statute, but is contrary to the plain language of the statute itself. The Public Staff reasons as follows:

> The phrase "pursuant to" – a complex preposition meaning "under" or "in accordance with" [footnote omitted] – when used with G.S. 62-133.8, clearly modifies "all purchases of electric power from renewable energy facilities and new renewable energy facilities," not the facilities themselves. .... Similarly, the phrase "to comply with any federal mandate that is similar to the requirements of subsections (b), (c), (d), (e), and (f) of G.S. 62-133.8;" which is not quoted by Movants, also modifies "all purchases of electric power from renewable energy facilities and new renewable energy facilities."

Thus, the Public Staff argues that the General Assembly intended for only the costs of bundled power purchased by a public utility to meet its own REPS obligations under either G.S. 62-133.8 or a similar federal mandate to be recoverable through G.S. 62-133.2(a1)(6).

Discussion and Conclusions

After careful consideration, the Commission finds good cause to grant, in part, the relief requested in the Joint Motion. To the extent an electric public utility purchases power from a swine or poultry waste-fueled renewable energy facility or new renewable energy facility to comply with the requirements of Senate Bill 3, as interpreted and implemented by Commission order, without purchasing the RECs associated with such power purchases, it may recover the costs of such purchases under G.S. 62-133.2(a1)(6) if such RECs are acquired by another electric power supplier for REPS compliance. Neither the amended fuel adjustment clause statute nor G.S. 62-133.8 contains an express requirement that the purchases of power and associated RECs be bundled as a prerequisite for cost recovery through G.S. 62-133.2(a1)(6), and for purposes of this case the Commission declines to impose one. The Commission's ruling, however, is limited only to the narrow facts of Movants' specific request addressing purchases of power from swine and poultry waste-fueled renewable energy facilities or new renewable energy facilities to comply with the set-aside requirements at issue.

Since enactment of the REPS statute, the Commission has repeatedly been presented with issues regarding the statewide aggregate swine and poultry waste set aside obligations. In each instance, the Commission has interpreted the statute consistent with the legislature's intent that North Carolina electric power suppliers be required to collectively purchase certain amounts of energy primarily generated from local swine and poultry waste resources.

So that an electric public utility will not be penalized by the REPS requirements, the General Assembly amended the fuel adjustment clause statute to allow full recovery through the fuel adjustment clause and REPS riders of all costs reasonably and prudently incurred to comply with the REPS requirements. Subsection (a1)(6) of the amended fuel adjustment clause statute specifically provides that, "[e]xcept for those costs recovered pursuant to G.S. 62-133.8(h), the total delivered costs of all purchases of power from renewable energy facilities and new renewable energy facilities pursuant to G.S. 62-133.8...." The Commission determines that the second "pursuant to" phrase is synonymous with the phrase "to comply with" found thereafter in the same subsection.

In implementing Senate Bill 3 and the statewide aggregate requirement of the swine and poultry waste set-asides, the Commission has approved pro rata requirements that may result in PEC or another electric public utility purchasing power generated from swine and poultry waste to comply with the statewide aggregate set-aside requirements that is not bundled with the RECs constituting the associated environmental attributes. To comply with the statutes as interpreted and implemented by the Commission, another electric power supplier will purchase these unbundled swine and poultry waste RECs for REPS compliance. As the electric public utility will be purchasing power from the poultry and swine waste-fueled renewable energy facilities or new renewable energy facilities to comply with the statewide aggregate swine and poultry waste set-aside requirements of G.S. 62-133.8, as interpreted and implemented by Commission order, its purchases satisfy the requirement of G.S. 62-133.2(a1)(6) that they be made to comply with

G.S. 62-133.8. The Commission, therefore, determines that, notwithstanding the fact that REC costs and ownership are apportioned among the electric power suppliers on a pro rata basis to meet the REPS statewide aggregate swine and poultry waste set-aside requirements, all of the energy associated with such RECs purchased is purchased "pursuant to G.S. 62-133.8" as provided in the fuel adjustment clause statute, G.S. 62-133.2(a1)(6).

The Commission takes judicial notice that North Carolina is the only state in the country that has adopted swine and poultry waste resource set-aside requirements as part of its renewable portfolio standard. Even more unique is the adoption of statewide aggregate standards for compliance with these set-aside requirements. But for these particular set-aside requirements, it is likely that few, if any, swine and poultry waste-to-energy generating facilities would be constructed in North Carolina to meet the general REPS requirement, and the issue raised in the Joint Motion would be moot because there would be no purchases from such facilities by this State's electric public utilities unbundled from the associated RECs. Therefore, to further efforts of the State's electric power suppliers to comply with these unique set-aside requirements, the Commission concludes that all purchases of electricity from swine and poultry waste-fueled electric generating facilities by this State's electric public utilities, whether bundled with or unbundled from the associated RECs, are made in order to comply with the provisions of G.S. 62-133.8 as long as the associated RECs are purchased by a North Carolina electric power supplier to comply with the REPS statewide aggregate swine and poultry waste set-aside requirements.

For the reasons set forth above, the Commission, therefore, concludes that the request for a declaratory ruling should be granted, in part, as follows: with regard to purchases of power by an electric public utility from renewable energy facilities or new renewable energy facilities where the electric public utility is not also purchasing the associated RECs, except for those costs recovered pursuant to G.S. 62-133.8, an electric public utility is entitled to recover through G.S. 62-133.2(a1)(6) the total delivered costs of all purchases of power from renewable energy facilities or new renewable energy facilities that are made to comply with the REPS statewide aggregate swine and poultry waste set-aside requirements of G.S. 62-133.8(e) and (f), as interpreted and implemented by Commission order, where the associated RECs are purchased by another North Carolina electric power supplier to comply with the REPS statewide aggregate swine and poultry waste set-aside requirements.

The Commission notes that Movants' specific request is limited to purchases of power made to meet the poultry and swine waste set-aside requirements as interpreted by prior Commission orders approving the pro rata mechanism. The Commission further notes, however, that, somewhat inconsistently, Movants' prayer for relief is not specifically limited to purchases of power made to meet the poultry and swine waste set-aside requirements, but is so broadly worded that it would also apply to other purchases of energy from renewable energy facilities or new renewable energy facilities. For example, the relief requested in the Joint Motion could apply to the purchase of renewable energy generated by a solar photovoltaic facility where the RECs were unbundled from the energy and sold to NC GreenPower or to another entity not subject to the North Carolina REPS requirement. The Commission does not believe that the amended fuel adjustment clause statute may be interpreted so broadly as to allow recovery through the fuel adjustment clause rider of the cost of all energy purchased from renewable energy facilities or new renewable energy facilities, "regardless of whether the electric public utility purchases the [REC] associated with the purchase of the renewable [energy]," as requested in Movants' prayer for relief. The Commission's Order herein, therefore, is strictly limited as set forth above to purchases of power from renewable energy facilities or new renewable energy facilities that are made to comply with the REPS statewide aggregate swine and poultry waste set-aside requirements of G.S. 62-133.8(e) and (f) where the associated RECs are purchased by another North Carolina electric power supplier to comply with the REPS statewide aggregate swine and poultry waste set-aside requirements.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 23rd day of November, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Sw112310.01

DOCKET NO. E-100, SUB 113
DOCKET NO. E-100, SUB 121

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 113	)	
	)	
In the Matter of	)	
Rulemaking Proceeding to Implement Session Law 2007-397	)	
	)	ORDER EXTENDING DEADLINE FOR THE ISSUANCE OF HISTORIC RECS
DOCKET NO. E-100, SUB 121	)	
	)	
In the Matter of	)	
Implementing a Tracking System for Renewable Energy Certificates Pursuant to Session Law 2007-397	)	

BY THE COMMISSION: In its August 3, 2010 Order issued in the above-captioned dockets, the Commission concluded that its rules should encourage the issuance of renewable energy certificates (RECs) in a tracking system as soon as possible following the production of the energy associated with the RECs. The Commission, therefore, ordered that, as of January 1, 2011, renewable energy facilities and new renewable energy facilities that participate in NC-RETS are only eligible for historic REC issuances for energy production going back two years.

To ensure that all facilities have an adequate opportunity to register with the Commission and with NC-RETS and to have their historic energy production data dating back to

January 1, 2008, reported to NC-RETS, the Commission finds good cause to extend the deadline until June 1, 2011, for REC issuances based upon historic energy production data. As noted in the Commission's earlier Order, this decision only affects the issuance of RECs for facilities participating in NC-RETS, and will have no effect on the issuance of RECs earned by facilities participating in other registries; such facilities will have to abide by their registries' rules regarding the eligibility of historic production data for REC issuance.

IT IS, THEREFORE, ORDERED that, on and after June 1, 2011, renewable energy facilities and new renewable energy facilities that participate in NC-RETS may have RECs issued for no more than two years' worth of historic energy production data.

ISSUED BY ORDER OF THE COMMISSION.
This the 10th day of December, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

kh121010.01

DOCKET NO. E-100, SUB 118
DOCKET NO. E-100, SUB 124

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of

Investigation of Integrated Resource Planning in North Carolina – 2008 and 2009	) ORDER APPROVING INTEGRATED) RESOURCE PLANS AND REPS) COMPLIANCE PLANS

HEARD: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on March 15, 16, 17, and 18, 2010

BEFORE: Commissioner William T. Culpepper, III, Presiding; Chairman Edward S. Finley, Jr.; Commissioner Lorinzo L. Joyner; Commissioner Bryan E. Beatty; and Commissioner Susan W. Rabon

APPEARANCES:

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

Len S. Anthony, General Counsel, and Kendal C. Bowman, Associate General Counsel, 410 South Wilmington Street, Post Office Box 1551, PEB 17A4, Raleigh, North Carolina 27602-1551

GENERAL ORDERS – ELECTRIC

For Duke Energy Carolinas, LLC (Duke):

Lara S. Nichols, Associate General Counsel and Charles A. Castle, Senior Counsel, Duke Energy Corporation, 526 South Church Street, EC03T/Post Office Box 1006, Charlotte, North Carolina 28201-1006

For Duke and Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (DNCP):

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For North Carolina Waste Awareness & Reduction Network (NC WARN):

John D. Runkle, Post Office Box 3793, Chapel Hill, North Carolina 27515

For Carolina Industrial Group for Fair Utility Rates (CIGFUR):

Carson Carmichael, Bailey & Dixon, L.L.P., Post Office Box 1351, Raleigh, North Carolina 27602-1351

For CPI USA North Carolina, LLC (CPI USA) and formerly known as EPCOR USA North Carolina, LLC:

M. Gray Styers, Jr., Styers & Kemerait, PLLC, 1101 Haynes Street, Suite 101, Raleigh, North Carolina 27604

For Haywood, Rutherford, and Piedmont Electric Membership Corporations (EMCs):

Charlotte A. Mitchell, Styers & Kemerait, PLLC, 1101 Haynes Street, Suite 101, Raleigh, North Carolina 27604

For the North Carolina Sustainable Energy Association (NCSEA):

Kurt J. Olson, 1111 Haynes Street, Raleigh, North Carolina 27608

For the Southern Environmental Law Center (SELC), Sierra Club, Environmental Defense Fund, and Southern Alliance for Clean Energy (collectively the Environmental Intervenors):

Gudrun Thompson, Southern Environmental Law Center, 200 West Franklin Street, Suite 330, Chapel Hill, North Carolina 27516

For the Using and Consuming Public:

Kendrick C. Fentress, Robert S. Gillam, and Lucy E. Edmondson, Staff Attorneys, Public Staff – North Carolina Utilities Commission (Public Staff), 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: General Statute 62-110.1(c) requires the North Carolina Utilities Commission (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 the issuance of a certificate for public convenience and necessity of construction of a generating facility. In addition, G.S. 62-110.1 requires the Commission to submit annually to the Governor and to the appropriate committees of the General Assembly a report of: (1) the Commission's analysis and plan; (2) the Commission's 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 making its analysis and plan pursuant to G.S. 62-110.1.

G.S. 62-2(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 . . . .

S.L. 2007-397 (Senate Bill 3), signed into law on August 20, 2007, amended G.S. 62-2(a) to add subsection (a)(10) that provides that it is the policy of North Carolina "to promote the development of renewable energy and energy efficiency through the implementation of a Renewable Energy and Energy Efficiency Portfolio Standard (REPS)" that will: (1) diversify the resources used to reliably meet the energy needs of North Carolina's consumers, (2) provide greater energy security through the use of indigenous energy resources available in North Carolina, (3) encourage private investment in renewable energy and energy efficiency, and (4) provide improved air quality and other benefits to the citizens of North Carolina. To that end, Senate Bill 3 further provides that "[e]ach electric power supplier to which G.S. 62-110.1 applies shall include an assessment of demand-side management and energy efficiency in its resource plans submitted to the Commission and shall submit cost-effective demand-side management and energy efficiency options that require incentives to the Commission for approval." G.S. 62-133.9(c).

Senate Bill 3 also specifically defines demand-side management (DSM) as "activities, programs, or initiatives undertaken by an electric power supplier or its customers to shift the timing of electric use from peak to nonpeak demand periods" and defines an energy efficiency (EE) measure as "an equipment, physical or program change implemented after 1 January 2007 that results in less energy being used to perform the same function." G.S. 62-133.8(a)(2) and (4). EE measures do not include DSM. G.S. 62-133.8(a)(4).

To meet the requirements of G.S. 62-110.1 and G.S. 62-2(3a), the Commission conducts an annual investigation into the electric utilities' integrated resource planning (IRP). IRP is intended to identify those electric resource options which can be obtained at least cost to the ratepayers consistent with adequate, reliable electric service. IRP considers both demand-side options, such as conservation, EE and DSM programs, and supply-side options, including alternative supply-side energy resources, in the selection of resource options.

Commission Rule R8-60 sets out the Commission's requirements for the electric utilities' IRPs and the process for review of such IRPs. The Commission first enacted Rule R8-60 in 1988 and revised it several times thereafter. The Rule was substantially altered by the Commission's Order issued on July 11, 2007, in Docket No. E-100, Sub 111. The 2007 revisions to Rule R8-60 require biennial reports with annual updates in lieu of annual reports, continual assessments by the utilities of programs that promote DSM and EE, an increased amount of information to be provided regarding those assessments, an expansion of the planning horizon from ten to fifteen years, and an accounting in the reports for the effects of demand response (DR) and EE programs and activities. On February 29, 2008, the Commission issued an order in Docket No. E-100, Sub 113, which revised existing Commission Rules and promulgated new rules implementing Senate Bill 3. The Commission further amended Commission Rule R8-60 and promulgated Rule R8-67(b), which directs electric power suppliers subject to Commission Rule R8-60 to file their REPS compliance plans as part of their IRP filings. Commission Rules R8-60 and R8-67 applied prospectively to the 2008 biennial reports. The 2008 biennial reports were the first reports filed pursuant to revised Commission Rule R8-60.

In its March 30, 2009 Order in Docket No. E-7, Sub 858, the Commission ordered Duke to file revisions to its 2008 IRP to address the undesignated load for sales similar to that in the Orangeburg Agreement at issue in that docket and the effects on Duke's future supply and generation requirements. In its November 10, 2009 Order in Docket No. E-7, Sub 923 (Central Order), the Commission ordered Duke to present as part of its 2009 IRP testimony a revised IRP that (1) moved the load associated with the power purchase agreement with Central Electric Power Cooperative, Inc. (Central) out of the undesignated wholesale load amount, (2) contained an explanation of a discrepancy in the Central Order, (3) provided the amount of load and projected load for each wholesale customer on a year-by-year basis through the terms of the current contracts, and explained any growth rates that differ from the projections for retail load, and (4) justified any amount of undesignated load in the revised IRP as to the potential customers' supply arrangements and the reasonable expectations for serving such customers. In its January 28, 2010 Order in Docket No. E-2, Sub 960, the Commission ordered PEC to reflect its additional retirements of coal-fired generation reasonably proportionate to the amount of incremental gas-fired generating capacity authorized by the Lee certificate issued in that docket above 400 MW in its 2010 and subsequent IRPs and to address its progress in retiring its unscrubbed coal units by updates in its annual IRP filings.

Commission Rule R8-60 requires that each of the investor-owned utilities (IOUs), the North Carolina Electric Membership Corporation (NCEMC), and any individual EMC, to the extent that it is responsible for procurement of any or all of its individual power supply resources (hereinafter, collectively, "the utilities"), furnish the Commission with a biennial report in even-numbered years beginning in 2008 that contains its current IRP together with all information required by subsection (i) of Rule R8-60 covering a two-year period. In odd-numbered years, each utility shall file an annual report containing an updated 15-year forecast, supply and demand-side resources expected to satisfy those loads, the reserve margin thus produced, as well as significant amendments or revisions to the most recently filed biennial report, including amendments or revisions to the type and size of resources identified, as applicable.[1] In addition, each biennial and annual report should (1) be accompanied by a short-term action plan that discusses those specific actions currently being taken by the utility to implement the activities chosen as appropriate per the applicable biennial and annual reports; (2) include the utility's REPS compliance plan pursuant to Rule R8-67(b); and (3) incorporate information concerning the construction of transmission lines pursuant to Commission Rule R8-62(p). Within 150 days after the filing of each utility's biennial report and within 60 days after the filing of each utility's annual report, the Public Staff or any other intervenor may file its own plan or an evaluation of, or comments on, the utilities' biennial and annual reports. Furthermore, the Public Staff or any other intervenor may identify any issue that it believes should be the subject of an evidentiary hearing. The Commission must schedule one or more hearings to receive public testimony.

Procedural History

Docket No. E-100, Sub 118

2008 IRPs were filed by the IOUs, NCEMC, Piedmont EMC (Piedmont), Blue Ridge EMC (Blue Ridge), Rutherford EMC (Rutherford), and EnergyUnited EMC (EU). REPS compliance plans were also filed by the IOUs, as well as GreenCo Solutions, Inc. (GreenCo),[2] Halifax EMC (Halifax), and EU.

On August 18, 2008, GreenCo requested a waiver of the requirement for each of its member EMCs to file individual REPS compliance plans and permission for it to file a consolidated REPS compliance plan on behalf of its member EMCs, with the exception of Halifax, Rutherford, and EU. On the same day, NCEMC, Blue Ridge, Piedmont, and French Broad requested a waiver of the requirement to file individual REPS compliance plans and

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[1] While the 2008 biennial reports and the 2009 annual reports may both be referred to hereinafter as "IRPs" for the respective years, it should be clear from Rule R8-60 that the requirements for a biennial report and an annual report differ.

[2] GreenCo filed a consolidated REPS compliance plan on behalf of Albemarle EMC, Blue Ridge, Brunswick EMC, Cape Hatteras EMC, Craven-Carteret EMC, Central EMC, Edgecombe-Martin County EMC, Four County EMC, French Broad EMC (French Broad), 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.

permission to have GreenCo file a consolidated REPS compliance plan on their behalf. On August 22 and 25, 2008, Duke filed a motion for an extension of time to file its biennial report and REPS compliance plan to November 3, 2008. On August 27, 2008, the Commission granted the requests of GreenCo, NCEMC, Blue Ridge, Piedmont, and French Broad for waiver of the requirement that each member EMC file an individual REPS compliance plan and for permission to file a consolidated report, and granted Duke's request for an extension of time to file its biennial report and REPS compliance plan. On August 28, 2008, Rutherford filed a notice with the Commission that its REPS compliance plan would be included in Duke's biennial report and REPS compliance plan. Also, on August 28, 2008, Rutherford filed its biennial report and Halifax filed its REPS compliance plan. On August 29, 2008, DNCP and EU filed their biennial reports and REPS compliance plans. On September 2, 2008, PEC filed its biennial report and REPS compliance plan. On September 12, 2008, NCEMC, Blue Ridge, and Piedmont filed their biennial reports, and NCEMC also filed its Energy Efficiency Potential Study Final Report. On the same day, GreenCo filed the consolidated REPS compliance plan and a motion for a protective order and confidential treatment for information attached to the consolidated report. On September 18, 2008, the Commission granted GreenCo's request for a protective order. On November 3, 2008, Duke filed its biennial report and REPS compliance plan. On January 29, 2009, Fibrowatt LLC (Fibrowatt) filed comments regarding the REPS compliance plans. On March 25, 2009, the Public Staff moved that the deadline for the filing of initial and reply comments on the biennial reports be extended. The Commission allowed the motion on March 30, 2009.

In addition to the Public Staff, the following parties intervened in Docket No. E-100, Sub 118: CIGFUR, NC WARN, Carolina Utility Customers Association, Inc. (CUCA), GreenCo, Fibrowatt, NCSEA, and the Attorney General.

On April 16, 2009, NC WARN filed its initial comments on the biennial reports and a request for an evidentiary hearing. On April 24, 2009, initial comments were filed by NCSEA, which were specifically in regard to the REPS compliance plans. Also, on April 24, 2009, the Public Staff submitted its initial comments. On May 27, 2009, reply comments were filed by the IOUs and the Public Staff. On the same day, NCSEA submitted additional comments.

On July 28, 2009, the Commission issued an Order Denying Request for Evidentiary Hearing, Scheduling Public Hearing, and Requiring Public Notice. This order set the public hearing in the Sub 118 docket for August 31, 2009. On August 12, 2009, NC WARN filed a Motion for Reconsideration and Renewal of Request of Hearing. The public hearing was held as scheduled. Six public witnesses testified in regard to REPS compliance plan issues.

Docket No. E-100, Sub 124

On or about September 1, 2009, the 2009 IRPs, which update the 2008 IRPs, were filed by the IOUs, NCEMC, Piedmont, Rutherford, EU, and Haywood. Blue Ridge had previously entered into a full requirements power purchase agreement with Duke whereby the entire Blue Ridge load is now included in Duke's IRP. Also, on or about September 1, 2009, the 2009 REPS compliance plans were submitted by the IOUs, GreenCo, Halifax, and EU. In addition to the Public Staff, the following parties initially intervened in the 2009 IRP proceeding: CIGFUR, CUCA, NC WARN, Nucor Steel-Hertford, and the Public Works Commission of the City of Fayetteville. The Attorney General filed a Notice of Intervention pursuant to G.S. 62-30.

On October 15, 2009, the Public Staff filed a motion for extension of time until January 15, 2010 for it and other intervenors to file alternative IRPs, annual reports, evaluations of, or comments on the 2009 IRPs.

On October 19, 2009, the Commission issued its Scheduling Order. In the Scheduling Order, the Commission consolidated the 2008 IRPs and the 2009 IRPs, reflecting Commission Rule R8-60 that requires the filing of biennial reports on the IRPs in even-numbered years and the filing of an update to that biennial report in odd-numbered years. The Commission found good cause to schedule an evidentiary hearing for the 2009 IRPs and REPS compliance plans filed by the IOUs. The Commission further directed that the 2009 IRPs filed by the other utilities (the non-IOUs) be addressed through the comment process contained in R8-60(j).

On November 20, 2009, EU filed an updated 2009 IRP. On December 11, 2009, DNCP filed the direct testimony and exhibits of Shannon L. Venable, M. Masood Ahmad, Michael J. Jesensky, and Aaron A. Reed; and PEC filed the direct testimony of David Kent Fonvielle, David Christian Edge, and Glen A. Snider. On January 11, 2010, Duke filed its revised 2009 IRP, the direct testimony and exhibits of Richard G. Stevie, Owen A. Smith, and James A. Riddle, and the testimony of Robert A. McMurry. On January 13, 2010, the Public Staff filed a second motion for extension of time to file comments on the non-IOUs' IRPs and REPS compliance plans, which was allowed by Commission order issued January 14, 2010. On January 29, 2010, CPI USA filed a petition to intervene, which was subsequently allowed. On February 8, 2010, the Public Staff filed comments on the non-IOUs' IRPs and REPS compliance plans. Haywood filed a letter in response to the Public Staff's comments on March 11, 2010.

On February 8, 2010, SELC filed a Petition to Intervene and Motion for Extension of Time to File Testimony. On February 11, 2010, the Environmental Defense Fund, Sierra Club, and Southern Alliance for Clean Energy also jointly filed a Petition to Intervene. On February 11, 2010, the Commission granted SELC's intervention and extended the date for the filing of intervenor testimony to February 19, 2010 and rebuttal testimony to March 9, 2010. On February 16, 2010, the Commission granted the intervention of the Environmental Defense Fund, Sierra Club, and Southern Alliance for Clean Energy.

On February 19, 2010, the Environmental Intervenors filed the testimony and exhibits of David A. Schlissel and John D. Wilson, CPI USA filed the testimony of Don C. Reading, NC WARN filed the testimony and exhibits of John O. Blackburn, and the Public Staff filed the affidavits of Jay B. Lucas, Jack L. Floyd, and Kennie D. Ellis and the testimony of John R. Hinton. On March 9, 2010, Duke filed the rebuttal testimony of Robert A. McMurry and the rebuttal testimony and exhibits of Richard G. Stevie, DNCP filed the affidavit of Shannon L. Venable, and PEC filed the rebuttal testimony of David Christian Edge, David Kent Fonvielle, and Glen A. Snider.

The public hearing regarding the 2009 IRPs and REPS compliance plans began at 7:00 p.m. on March 15, 2010 with ten public witnesses testifying before the Commission as members of the using and consuming public: Michael Thomas Cherin, June Blotnick, Alice Loyd, Elizabeth R. Hutchby, Beth Henry, Miriam Thompson, Bob Rodriquez, Zell McGee, Harry Phillips, and Mary McDowell. The public hearing was reopened at 9:30 a.m. on March 16, 2010, with Ryan William Thompson testifying as a public witness. The public witnesses generally testified in favor of energy conservation and efficiency and renewable energy, especially wind and solar, and against investment in traditional generating facilities. Many of the witnesses brought up the risks of additional coal plants to the health of North Carolina residents and to the environment. The Commission also received five letters and e-mails from customers, generally expressing strong support for energy conservation and renewable energy and urging the Commission to pursue these as integral elements in the utilities' current planning in lieu of fossil-fueled generation.

Following the conclusion of the public hearing, the parties stipulated that the testimony and affidavit of DNCP witness Venable, the testimony and exhibit of DNCP witness Ahmad, and the testimony of DNCP witnesses Jesensky and Reed be entered into the record. PEC presented the direct and rebuttal testimony of David Kent Fonvielle, Director of Fleet Optimization, David Christian Edge, Manager of Retail Market Strategy, and Glen A. Snider, Manager of Resource Planning. Duke presented the direct and rebuttal testimony of Richard G. Stevie, Managing Director of Customer Market Analytics, and Robert A. McMurry, Director of Integrated Resource Planning and the direct testimony of Owen A. Smith, Managing Director of Renewable Strategy and Compliance, and James A. Riddle, Manager of Load Forecasting in the Customer Market Analytics Department. NC WARN presented the direct testimony of John O. Blackburn, Ph.D., Professor Emeritus of Economics, Duke University. The Public Staff presented the testimony of Jack L. Floyd, Kennie D. Ellis, and Jay B. Lucas, engineers with the Electric Division of the Public Staff and John R. Hinton, Financial Analyst with the Economic Research Division of the Public Staff. The Environmental Intervenors presented the testimony of John D. Wilson, Director of Research for the Southern Alliance for Clean Energy, and David A. Schlissel, President of Schlissel Technical Consulting, Inc. CPI USA presented the testimony of Don C. Reading, Vice President and Consulting Economist with Ben Johnson and Associates, Inc.

On June 10, 2010, a brief was filed by NC WARN. On June 11, 2010, briefs were filed by the Environmental Intervenors and CPI USA. Also on June 11, 2010, proposed orders were filed by DNCP, PEC, Duke, and the Public Staff. On June 17, 2010, NC WARN filed a correction to its brief.

Although made shortly after the parties' post-hearing filings, approval of the 2008 IRP filings comes later than otherwise would have been the case due primarily to a change in

Commission Rule R8-60 requiring an update to the even-year IRP filings. The next IRP filings will be due on September 1, 2010. With one round of IRP proceedings under new procedural rules behind us, the Commission contemplates that the 2010 filings and the Commission's determination will be timely and in accordance with the schedule and procedure prescribed in Commission Rule R8-60. Accordingly, with respect to future IRP proceedings, all parties are advised that requests for extensions of time will be appropriately scrutinized with an eye toward keeping the proceedings on schedule in order to serve the purposes of the governing statute.

Based upon the foregoing, the information contained in the 2008 biennial reports, the 2009 annual updates to the 2008 biennial reports, the REPS compliance plans, the testimony and exhibits introduced at the hearings, and the Commission's 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 and should be approved.

2. The IOUs' 2008 biennial reports, and the 2009 annual updates to the 2008 biennial reports, are reasonable and should be approved.

3. The IOUs' 2009 REPS compliance plans are reasonable and should be approved.

4. The IOUs should continue to investigate the opportunities to utilize air conditioning cycling load management programs as a way to reduce load and to reduce fuel costs.

5. The 2008 biennial reports, and the 2009 annual updates to the 2008 biennial reports, and 2009 REPS compliance plans submitted by NCEMC, Piedmont, Blue Ridge, Rutherford, EU, Haywood, GreenCo, and Halifax are reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

The evidence supporting this finding of fact is contained in the testimony of DNCP witnesses Ahmad and Venable, PEC witnesses Snider and Edge, Duke witnesses McMurry, Riddle, and Stevie, NC WARN witness Blackburn, Environmental Intervenor witness Wilson, and Public Staff witnesses Hinton, Ellis, and Floyd, and the 2009 IRPs of DNCP, PEC, and Duke.

DNCP witness Ahmad adopted the portions of DNCP's 2009 IRP dealing with its annual load forecast, as well as its proposed supply-side resources. Chapter 2 of DNCP's 2009 IRP contains its description of methodology for forecasting its peak demand and energy sales needs. DNCP's 15-year forecast from 2010 through 2024 predicted that its summer peaks will grow at an annual average rate of 2.0% after the effects of EE and DSM are included. DNCP's energy sales are predicted to grow at an average annual rate of 2.2% after DSM and EE are included. DNCP is obligated to maintain a reserve margin for its portion of the PJM coincidental peak load, resulting in an effective reserve margin requirement of 12%. Public Staff witness Hinton testified that DNCP's forecasts of peak demand and total energy sales were valid and reasonable for planning purposes.

PEC's 15-year forecast from 2010 through 2024 contained in its 2009 IRP indicates that its system peak loads will grow at an annual average rate of 1.6% after the effects of EE and DSM are included. PEC's energy sales are predicted to grow at an average annual rate of 1.4% after the effects of EE and DSM are included. According to PEC witness Snider, this forecasted growth is comparable to PEC's forecasts in recent years. He also stated that there has been a reduction in the peak load forecast and growth in the near term due to the continuation of the current economic downturn. Mr. Snider further indicated that PEC used the same methods, tools, and models in its 2009 IRP that it employed to develop load and energy forecasts presented to this Commission in prior IRP proceedings in recent years. PEC's 2009 IRP reflects reserve margins of approximately 13% to 26%. Public Staff witness Hinton agreed that PEC's growth rates in the 2009 IRP were similar to those in the 2008 IRP. He further testified that PEC's forecasts of peak demand and total energy sales were reasonable and valid for planning purposes. PEC witness Edge presented testimony regarding PEC's DSM and EE forecasts, as well as its programs and plans. He testified that between 2009 and 2023, PEC forecasts that the projected savings impact for all cost-effective EE will be 3.8% of total retail energy sales.

Duke's 15-year forecast from 2010 through 2024, as reflected in its revised 2009 IRP, predicted that its summer peaks after EE will grow at an annual average rate of 1.8%. Duke's energy sales are predicted to grow at an average annual rate of 1.6% after accounting for the effects of EE. Duke witness McMurry testified that Duke's revised 2009 IRP incorporates a target planning reserve margin of 17%, which Duke's historical experience has shown to be sufficient. Witness Riddle noted that the load forecast portrays the level of expected peak demand prior to any reductions for DSM programs, which are captured and incorporated in the development of the IRP as an offset to the load forecast. Duke witness Stevie noted that after the inclusion of the EE programs, retail sales projected for 2014 are actually below the level for 2009.

Pursuant to the Central Order, Duke's revised 2009 IRP moved the Central wholesale load from undesignated load, provided the amount of load and projected load for each wholesale customer and an explanation for a discrepancy between the growth rates between the wholesale loads and Duke's retail loads, and provided a justification for any amount of undesignated load and the reasonable expectations for serving such customers. Duke witness Riddle testified that he projects slightly less than 1% growth attributable to retail customers with EE and 1.3% without EE, and slightly more than 3.5% to 4% growth attributable to wholesale customers over the 15-year period. Mr. Riddle in his direct testimony addressed possible reasons for the differences in the demand of Duke's wholesale customers as opposed to its retail customers. He pointed out that, in general, wholesale customers' usage is concentrated more with residential and commercial end users with comparatively less industrial usage, as compared to Duke's retail usage, which is more widely distributed among the industrial, commercial, and residential classes. Mr. Riddle stated that because of these characteristic differences, different growth rates are to be expected. He also pointed out that the Central contract provides for a seven year step-in to the customer's full load requirement, with Duke providing 15% of Central's total member cooperative load in 2013, followed by 15% annual increases in load over the subsequent six years until all of the contract load is met.

Duke witness McMurry testified regarding the inclusion of the Central load as a firm requirement and the undesignated load associated with wholesale customers Duke believes it has a reasonable expectation to serve. He was questioned as to the analysis Duke uses to determine whether it has a "reasonable expectation" of serving a customer. Mr. McMurry testified that Duke used an estimate based on whether it believed it had more than a 50% chance of serving a particular customer within the foreseeable future. While Mr. McMurry could not provide an exact answer as to how Duke defined the "foreseeable future," he stated that if it did not appear that a contract would begin in the next two years, Duke should not include that customer in its current IRP. Mr. McMurry said that in such a case, Duke should include the contract in the following IRP if Duke had a reasonable expectation of serving that customer. Mr. McMurry agreed that each wholesale contract differed as to its individual facts and circumstances and that this analysis of whether Duke had a "reasonable expectation" of serving a particular wholesale customer involved a certain amount of subjectivity. He testified that both the inclusion of the Central load and the specified undesignated wholesale load associated with customers whom Duke has a reasonable expectation to serve increased the need for combustion turbine generation in the 2017 and 2026 timeframe.

Public Staff witness Ellis noted that Duke's 2009 IRP filed September 1, 2009, maintained a reserve margin averaging 18.8% throughout the planning horizon, while its revised 2009 IRP incorporated undesignated wholesale load and some changes to the capacity addition schedule, resulting in a reserve margin averaging 19.1% through the planning horizon. Public Staff witness Hinton testified that before inclusion of Duke's wholesale loads, the growth rate of Duke's summer peak demand from 2010 through 2024 is 1.2%, and the growth rate for total energy sales is 1.1%, which is similar to the growth rates in Duke's 2008 IRP. He further testified that the addition of the Central wholesale load and the undesignated load increases the growth rate of the summer peak demand to 1.8% and the growth rate of its total energy sales to 1.6%. Mr. Hinton testified that he found Duke's forecasts of peak demand and total energy sales to be valid and reasonable for planning purposes.

Duke witness McMurry testified that Duke's load forecast was updated to account for the projected load impacts for EE and demand-side resources associated with the settlement in Docket No. E-7, Sub 831 (save-a-watt). Duke witness Stevie testified that the conservation impacts were assumed at 85% of the target impacts from the terms of the save-a-watt settlement (Base Case). Dr. Stevie further testified that the projected load impacts from the conservation programs were based upon three bundles of the portfolio of programs with a new bundle entering every four years. The projected load impacts from Duke's DSM programs are based upon continuing and new DR programs. Dr. Stevie explained that the projection of EE impacts in the 2009 IRP differed in several respects from the 2008 projection: the start of the programs was delayed to the middle of 2009, the EE impacts were scaled up in the third and fourth years consistent with the save-a-watt settlement, and new information on the load shape associated with hourly load savings from the installation of compact fluorescent light bulbs was incorporated into the projection of the coincident peak load impacts. Dr. Stevie explained that the load forecasts prepared by Duke witness Riddle capture the effects of EE trends and activities, including EE resulting from rising fuel prices that occur outside of the Company's own EE programs. Dr. Stevie testified that under Duke's Base Case, which was scaled down to 85% of the projected impacts from the save-a-watt settlement, it projected that by 2020 it would have cumulative energy savings of 4.5% to 5%, or 7% if the effect of increasing energy prices is included. Under Duke's High Case scenario,[1] Dr. Stevie testified that Duke projects a 13.5% decrease in retail sales as a result of EE and DSM by 2029. However, Dr. Stevie testified that although Duke is committed to pursuing all cost-effective EE, he believes achieving the savings target in its High Case would be quite a "stretch." Duke witness McMurry indicated on cross examination that it was too early to tell whether Duke would be able to meet the EE goal to which it had agreed in the save-a-watt docket. He pointed to the number of industrial and commercial customers opting out, as well as a weak adoption rate as potential causes for Duke to miss the goal. He stated that Duke was making its best efforts, but that success in reaching the goal was also contingent on the availability of cost-effective EE.

Public Staff witness Floyd noted that the 2009 IRPs of Duke, PEC, and DNCP included slightly lower impacts from DSM and EE resources than their 2008 IRPs. He opined that this difference is the result of delays in implementation of DSM and EE programs due to current economic conditions, as well as delays in the timing of development, approval, and rollout of the various programs within each portfolio.

NC WARN witness Blackburn testified that the forecasts of PEC and Duke overstated the demand for electricity. Dr. Blackburn produced a plan in which he deducted new wholesale contracts that he deemed unnecessary and recommended an annual EE goal of 1.5%. Dr. Blackburn did not intend that the utilities adopt an annual EE goal of 1.5% for their utility-administered programs, rather he believes that this amount of annual EE savings is achievable in North Carolina during the planning horizon through a combination of utility-sponsored programs, revised building codes, and governmental, individual, and corporate initiatives. In fact, Dr. Blackburn stated that if there were changes in building codes and local, state and federal standards, issuance of executive orders, and governmental initiatives increasing EE, there might be little left for the utilities to do.

Duke witness Stevie questioned the studies on which Dr. Blackburn relied to arrive at his recommendation of a 1.5% annual savings goal for EE. He cited a January 2009 study by the Electric Power Research Institute that implied a reasonable annual savings recommendation of approximately 0.6%. Dr. Stevie pointed out that 8% of Duke's total retail load from the commercial and industrial sector had chosen to opt-out from participation in Duke's EE programs. Duke witness McMurry pointed out that Dr. Blackburn's proposed plan had removed the wholesale contract to supply the load of Central, a wholesale customer that had been historically served by Duke. He also pointed out that Dr. Blackburn's analysis did not provide for any reserve margin and did not contain any detailed cost analysis. PEC witness Edge questioned the American Council for an Energy-Efficient Economy (ACEEE) study cited by Dr. Blackburn, in that it did not take into consideration the opt-out provision available to commercial and industrial customers in North Carolina, which represents 40% of PEC's retail sales. He also

[1] The High Case scenario uses 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 annually until the load impacts reach the economic potential identified by the 2007 market potential study.

pointed out that the ACEEE study reported projected savings in terms of gross savings, while PEC's savings projections are based on net savings. Mr. Edge testified that he believed that it would be inconceivable for PEC to have a goal of 1% annual energy savings over the planning horizon based on PEC's analysis of cost-effective potential EE based under the screening of the total resources cost test.

Environmental Intervenor witness Wilson testified that for 2010, the utilities forecast reducing system sales by 0.3% through EE programs, which he termed a "good start." Mr. Wilson calculates cumulative energy savings from the utilities of 3.1% over the next 15 years. He recommended an annual goal of 1% with projected savings of up to 15% by 2024 for the utilities. PEC witness Edge testified on rebuttal that he disagreed with Mr. Wilson's contention that PEC should have a goal of achieving savings from EE of 15% by 2024. Mr. Edge criticized the studies on which Mr. Wilson relied in that none were specific to PEC's service area, some only projected economic potential, some did not consider the effects of "free riders,"[1] some were regional while others were national in scope, some were meta-analyses of other studies, some relied on implementation of policies beyond those utility-implemented programs, and none took into account the opt-out provision of Senate Bill 3. Mr. Edge testified that both the 15% target by 2024 advocated by Mr. Wilson and the 1.5% annual target advocated by Dr. Blackburn were overly optimistic as they failed to account for the opt-out provision of Senate Bill 3 or new governmental efforts to stimulate EE that reduce the savings potentials for utility-administered programs. Mr. Edge testified that PEC should not rely on the aspirational goals proposed by Dr. Blackburn or Mr. Wilson, but rather on its own comprehensive analysis of available EE and DSM potential in its service territory and its experience implementing and evaluating its programs. Mr. Edge testified that comparison with the EE achievements in states such as Vermont, California, and New Jersey was unfair when numbers from those states' programs reflected achievements prior to the enactment of the Energy Independence and Security Act (EISA), which banned continued used of incandescent light bulbs. The numbers from those programs also do not account for free riders. Mr. Edge testified that in 2007, PEC committed to defer 1000 MW of generation through DSM and EE and that PEC projects a savings of 3.8% through EE and DSM by 2023. PEC witness Snider pointed out that supply-side resources differed from demand-side resources in that a planner could anticipate the quantity of the supply-side resources with greater certainty than with demand-side resources. He testified that this lack of certainty regarding demand-side resources translates into concerns regarding reliability and risk when forecasting DSM and EE.

DNCP witness Venable disagreed with Mr. Wilson's suggestion that the IOUs should meet an annual energy savings goal of 1%, as that target exceeds the requirements of Senate Bill 3. Nonetheless, Ms. Venable testified that DNCP is committed to pursuing EE that is cost-effective and appropriate for its customers.

In making his recommendation of an annual goal of 1% with projected savings of up to 15% by 2024 for the utilities, Environmental Intervenor witness Wilson pointed to states with lower or comparable electricity rates that had achieved much higher rates of EE savings. Duke

[1] "Free riders" are generally described in the testimony as customers who undertake EE measures on their own initiative, without the influence of utility participant incentives. PEC witness Edge indicated that the energy savings resulting from free riders are not reflected in PEC's projections of energy savings.

witness Stevie disagreed with Mr. Wilson's contention that there was little correlation between electricity prices and EE savings and sponsored a rebuttal exhibit showing what he termed "a direct and significant relationship" between the price of electricity and the percent annual incremental EE achievement. Dr. Stevie further testified that it is easier to find cost-effective EE when rates are higher than when they are lower. PEC witness Edge also disagreed with Mr. Wilson's analysis of the correlation between electricity prices and EE. Mr. Edge pointed out that the 2009 ACEEE study cited by Mr. Wilson acknowledges that the highest EE cost savings have been achieved in states with high electricity rates. Mr. Edge also pointed out that there was a correlation between the level of electricity prices and the number of cost-effective EE programs and measures in a state.

Based on the foregoing, the Commission concludes that the energy and peak load forecasts of the IOUs are reasonable and appropriate. The IOUs' forecasting methodology is well accepted in the industry and has proven over time to be reasonably accurate. While the EE savings goals suggested by Dr. Blackburn and Mr. Wilson may seem attractive, they fail to take into account the opt-out provision of Senate Bill 3, which allows a significant portion of the potential market for savings from EE to decline participation in the utilities' programs. Moreover, the utilities' post-Senate Bill 3 programs are in their early stages and have not been rolled out as quickly as anticipated due to various reasons enumerated above by both utility and Public Staff witnesses. As such, the projections of EE and DSM savings forecasted by the IOUs are found to be reasonable within this proceeding for planning purposes. This should not be regarded as any indication of low expectations for EE and DSM savings on the part of the Commission. These projections are subject to review and re-evaluation in future IRP proceedings and should not be regarded as static. These projections very well could change as the utilities' EE and DSM programs mature and are subject to measurement and verification, and as opportunities for refining existing programs or creating new programs appear on the horizon.

In regard to the appropriate treatment of wholesale load, the Commission finds that in future IRPs, all utilities should be required 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. Further, the approval of any IRP that includes undesignated load should not be cited as advance approval of any wholesale contract or method of cost allocation associated with any wholesale contract in a future proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

The evidence supporting this finding of fact is contained in the testimony of DNCP witnesses Jesensky and Venable, PEC witness Snider, Duke witnesses McMurry, Riddle, and Stevie, NC WARN witness Blackburn, Environmental Intervenor witnesses Wilson and Schlissel, and Public Staff witness Ellis, and the 2008 and 2009 IRPs of DNCP, PEC, and Duke.

DNCP witness Venable presented testimony regarding the utility's 2009 IRP, including an overview of the IRP process and a discussion of the Company's plans for future REPS filings. She noted in her direct testimony that DNCP's 2009 IRP included provisions to achieve policy goals from individual state legislatures. DNCP witness Jesensky discussed the utility's current, proposed, and future DSM programs. DNCP's IRP indicates that it has not filed for approval of DSM programs in North Carolina, but plans to implement a portfolio of DSM programs in Virginia after the Virginia State Corporation Commission approves them, and will evaluate and consider these programs for approval and implementation in North Carolina.[1] Environmental Intervenor witness Wilson recommended that DNCP file its proposed EE programs in North Carolina as expeditiously as possible and recommended that all the utilities participate in a regional EE database and collaboration process. According to DNCP witness Venable, while DNCP does not support the creation of a regional EE database and collaboration process, it does support an inclusive stakeholder process.

PEC witness Snider testified that he oversaw the development of PEC's 2009 IRP. According to Mr. Snider, with regard to new supply resources, the only resources PEC is committed to install are the combined-cycle generation facilities at PEC's Richmond County and Wayne County sites. He stated that all other generation additions shown in PEC's plan are generic resources indicating the need for additional generation. According to Mr. Snider, PEC has made no commitments to any specific type, amount, location, or ownership of the needed capacity.

Duke witness McMurry testified that he oversees long-term resource planning for Duke. According to Mr. McMurry, based on the results of the 2009 IRP, the assumed retirement dates of Duke's older fleet of combustion turbines at Buck Steam Station, Dan River Steam Station, Riverbend Steam Station and Buzzard Roost Combustion Turbine Station were accelerated from the 2014-2015 timeframe to June 2012, and the remaining coal units without scrubbers at Buck Steam Station Units 5 and 6 and Lee Steam Station Units 1 through 3 were assumed to be retired in 2020 based on expected increased regulatory scrutiny. He stated that these planned retirements total an additional 625 MW of retired generation in the 2009 IRP as opposed to the 2008 IRP. Mr. McMurry testified that due to the impact of the recession on load growth, the combustion turbine portion of the new Buck combined cycle plant will not be operable during the summer of 2011, and the need for the new Dan River combined cycle plant has been delayed until the summer of 2013. Based on Duke's analysis, it determined that the addition of the Central load increases the need for combustion turbine generation in the 2017 and 2026 timeframe and supports the need for nuclear generation in the 2018 to 2021 timeframe. Mr. McMurry testified that the nuclear project cost escalation rate was also reduced from the 2008 to 2009 IRP. He stated that even with the inclusion of the updated information for the revised 2009 IRP, the basic conclusions of the 2008 IRP are unchanged.

NC WARN witness Blackburn testified that, in his opinion, substantially all of Duke's and PEC's coal plants could be phased out within the planning period without the addition of new nuclear generation if the following goals were achieved: (1) an annual EE goal of 1.5% over the planning period, (2) a renewable energy goal of 20%, and (3) a customer cogeneration

[1] The Commission notes that in Docket No. E-22, Sub 418, on March 11, 2010, DNCP was ordered to file for approval appropriate demand response (DR) programs for its North Carolina customers by September 1, 2010.

or combined heat and power (CHP) goal that amounts to 16-17% of total power generation in North and South Carolina. Dr. Blackburn noted that in his plan, existing hydroelectric power would be allowed to count toward the renewable energy target. Dr. Blackburn conceded on cross-examination that his plan did not include any reserves and that additional costs for transmission, grid stability, and voltage control would be incurred if the renewable resources envisioned under his plan were added to the grid. Dr. Blackburn also agreed that implementation of his plan could require changes in laws and policies beyond the purview of the Commission.

Dr. Blackburn testified about a study he performed regarding how wind and solar might offset each other when operated in tandem despite their intermittent nature. His study showed that while the stream of electricity from the two sources still fluctuated when operated in tandem, it was much more stable. He concluded that while intermittency is a problem, it is manageable. On cross-examination, Dr. Blackburn admitted that he had matched loads on an hourly basis, rather than on a second or minute basis. He further conceded that of the 123 days of his study, there were three days when there was an inadequate supply of electricity and 17 hours when there was a need for back-up generation. The study also assumed from the onset that consumption was reduced by 20% due to EE.

Duke witness McMurry testified on rebuttal that history indicated that it was not economically feasible for customers to build CHP facilities on a large scale, and that he deemed Dr. Blackburn's CHP goal unrealistic. Mr. McMurry found Dr. Blackburn's plan to be flawed, and declared it to be a plan that would result in both higher costs and less reliability, contrary to the goals of IRP. Mr. McMurry referred to Dr. Blackburn's proposal as a "vision plan" as opposed to a resource plan.

Environmental Intervenor witness Schlissel testified that Duke's emissions from carbon will increase in each of its resource portfolios between 2010 and 2029 despite its plan to retire 1,600 to 1,700 MW of cycling coal units by 2020 as a result of the addition of Cliffside Unit 6. He also advocated that Duke and PEC consider the regulation of coal combustion products (CCPs) in their IRPs. Mr. Schlissel recommended that Duke use a wider range of carbon prices and testified that the methodology PEC used to make its assumptions regarding carbon prices was inadequate. He stated that if Duke were to build more natural gas fired generation, it would diversify Duke's portfolio and lower its emissions, especially since natural gas has been forecasted to have a greater supply and a lower price than had been previously thought. Mr. Schlissel pointed out that PEC mentions potential regulation of coal combustion waste as a significant challenge, but that Duke's IRP does not address the issue. He criticized Duke and PEC for not sufficiently reflecting the current and upcoming regulatory challenges surrounding air emissions. Mr. Schlissel recommended that the Commission require the utilities to include a detailed discussion and analysis of pollution control standards and to show how these are factored into their IRPs.

Duke witnesses McMurry and Riddle testified that one major difference between Duke's 2008 and 2009 IRPs was that Duke began incorporating the expected impact of greenhouse gas regulation into its load forecast in its 2009 IRP. However, Duke did consider the impact of carbon legislation in its 2008 IRP in its Higher Carbon Case analysis. Duke witness McMurry testified on rebuttal that as a result of its planned retirements and additions, including Cliffside 6, Duke's CO_2/MWh emissions will decline by 30% by 2029. He also pointed out that adding natural gas-fired plants would not significantly alter the dispatch order for generation and therefore not significantly impact Duke's CO_2 emissions. Mr. McMurry further testified that even with lower natural gas prices, Duke's analysis indicates that it would not be cost-effective to retire other coal-fired plants and replace them with natural-gas-fired plants. He testified that while not explicit in its IRP, Duke's analysis did consider the regulation of coal ash and its by-products. While Mr. McMurry did not agree with Mr. Schlissel that Duke should have used a wider range of potential carbon prices in its 2009 IRP based on the circumstances at that time, he stated that Duke may consider using a wider range in its 2010 IRP.

PEC witness Snider testified that PEC's plan reflects acknowledgment of the widely accepted assumption that there will be environmental legislation in the future requiring review of continued operation of certain coal-fired generation. This potential environmental legislation includes a carbon tax, the Clean Air Interstate Rule, maximum achievable control technology requirements in the wake of the vacatur of the Clean Air Mercury Rule, revision of the National Ambient Air Quality Standards for ground-level ozone, regulation of CCPs, and other laws or rules dealing with global climate change. According to Mr. Snider, as the 2009 IRP was an update to the 2008 IRP, PEC factored these legislative changes into its cost assumptions, but did not run different sensitivities when performing its IRP modeling in 2009.

Environmental Intervenor witness Wilson testified that the IOUs still treat EE as a second-class resource by failing to consider demand-side resources on an equivalent basis with supply-side resources. He noted that while all of the IOUs described their various EE or DSM programs in their 2009 IRPs, they did not describe the capacity, energy, number of customers and other required information for each program over the 15-year period. Mr. Wilson pointed out that this descriptive data was important for the Commission to analyze whether demand-side resources were being considered on an equal footing with supply-side resources. He further testified that both Duke's Base Case and its High Case appear to have been developed in a manner that does not reflect the program design principles and intent of the approved programs, in that they understate the probable impact of Duke's EE programs. Mr. Wilson recommended that Duke revise its resource plan to reflect a consistent trend in EE program growth consistent with available EE potential and opportunities for reasonable program growth. He also found certain information in PEC's IRP regarding the capacity and energy impacts of its demand-side resource forecast to be inconsistent or confusing. Mr. Wilson contended that neither Duke nor PEC performed a comprehensive analysis of demand-side resources in their 2009 IRPs. He recommended that the utilities either perform an EE potential study that captures all possible EE measures or set an annual energy savings goal that is benchmarked against leading efforts across the country. Mr. Wilson suggested that the Commission require the utilities in their resource planning to provide a more detailed explanation of how they selected their preferred portfolios, consider risks that cause short-term rate spikes, and create a regional EE database and collaboration process.

Duke witness Stevie disagreed with Mr. Wilson's contention that Duke relegated EE to a second-class status. Dr. Stevie explained that Duke evaluates demand and supply-side resources in a portfolio modeling exercise by having them compete with each other in an optimization model. While Dr. Stevie agreed with Mr. Wilson that Duke should have described the capacity, energy, number of customers and other required information for each EE or DSM program over the 15-year period, he disagreed with Mr. Wilson's charge that Duke had not included a comprehensive analysis of EE measures in its IRP. Dr. Stevie testified on rebuttal that Duke had already engaged in a bottom-up approach to study the economic potential of EE as advocated by Mr. Wilson. Dr. Stevie agreed with Mr. Wilson's statement that neither an EE potential study nor industry experience can provide as precise measure of cost-effective EE as a supply-side generation plan that can anticipate generation capacity. Dr. Stevie pointed out that there is greater uncertainty associated with the implementation of EE programs that can only be resolved as experience is gained with the newly implemented programs. He testified that as Duke had an ongoing collaborative process, there was not a need for a regional collaborative as suggested by Mr. Wilson. However, Dr. Stevie agreed with Mr. Wilson that a regional database should be created and kept up to date. Dr. Stevie testified that Duke should update its market potential study at least every five years, thus the 2007 study should be updated by at least 2012.

PEC witness Snider noted in his rebuttal testimony that PEC had assumed in IRPs prior to 2009 that all longer term power purchase agreements (PPAs) were perpetually renewed. PEC's 2008 IRP lists six wholesale PPAs with four entities that were assumed to be renewed following the expiration of the contracts. Beginning with the 2009 IRP, PEC assumed that such PPAs would expire at the end of their current terms. Mr. Snider listed several factors in support of this change. PEC has the right to purchase capacity only for the duration of the existing contract. At the expiration of the contract, the owner might elect to sell the capacity and energy to another purchaser, the facility might not be capable of providing reliable power to PEC, the owner might not have the financial ability to support a future agreement, or PEC might determine that the resource is not optimal for a variety of reasons. In the case of a facility producing renewable energy, the viability of the facility may be affected by external factors such as tax credits, steam hosts, renewable status, and environmental compliance.

Public Staff witness Ellis testified that the discussions of generating facilities, reserve margin adequacy, non-utility generation, wholesale power contracts, transmission facilities, transmission planning, evaluation of resource options, and levelized busbar costs in the 2009 IRPs of DNCP, PEC, and Duke, which were updates to the 2008 biennial reports, appeared to meet the requirements of R8-60.

Rule R8-60(h) requires that annual reports, such as the 2009 IRPs, contain an updated 15-year forecast of native load requirements and other system capacity or firm energy obligations; supply-side and demand-side resources expected to satisfy those loads; the reserve margin thus produced; significant amendments or revisions to the most recently filed biennial report, including amendments or revisions to the type and size of resources identified, as applicable; a short-term action plan that discusses those specific actions currently being taken by the utility to implement the activities chosen as appropriate; and the utility's REPS compliance plan pursuant to Rule R8-67(b). Unless there have been significant amendments or revisions to the biennial plan, the utility in an annual report is not required to perform the comprehensive analysis of all resource options pursuant to Rule R8-60(c)(2), nor to provide the items required by Rule R8-60(d), (e), (f), and (g). Utilities may certainly provide this information on a voluntary basis. This was the first year that the utilities filed annual IRP reports pursuant to the revised Rule R8-60, and it appears that there was confusion regarding the difference in requirements for a biennial report and an annual report. In order to reduce such confusion, the Commission will require the inclusion in future annual reports of an introduction in which the utilities list any circumstances which necessitate significant amendments or revisions to the most recently filed biennial reports and specify the portions of such biennial reports that have been amended or revised.[1]

Because the 2009 IRPs were annual reports as opposed to biennial reports, the utilities were not required to perform the same level of analysis as required for a biennial report unless there had been significant changes or revisions. It appears that to some extent, both PEC and Duke took into account the changes in environmental regulation occurring in the interval between their 2008 and 2009 IRPs. The regulatory climate surrounding climate change, CCPs, and other environmental issues certainly changed from the filing of the 2009 IRPs in September 2009 to the time of the hearing in March 2010, and the Commission expects that it will have changed by the time the 2010 IRPs are filed in September 2010. The biennial reports are to contain all required information, full and robust analyses and sensitivities, which should encompass a range of scenarios including potential regulatory changes.

While it should be clear at this point, the Commission reiterates that inclusion of a DSM or EE program, a proposed new generating station, a proposed new transmission line, or a purchased power contract in a utility's IRP filing does not constitute approval of any of those aspects of the plan even if the IRP as a whole is approved.

Based on the foregoing, the Commission's review of the 2009 annual updates and the 2008 biennial plans, and the entire record of this proceeding, the Commission concludes that the 2008 and 2009 IRPs submitted by the IOUs are reasonable for purposes of this proceeding and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

The evidence supporting this finding of fact is contained in the testimony of Duke witness Smith, DNCP witnesses Reed and Venable, PEC witness Fonvielle, CPI USA witness Reading, and Public Staff witnesses Lucas and Ellis, and the 2009 REPS compliance plans of DNCP, PEC, and Duke.

Duke witness Smith testified that under G.S. 62-133.8(b)(1), each utility in the State must comply with the REPS requirement in accordance with a statutorily set schedule based upon 3% of the utility's North Carolina retail sales beginning in the year 2012, 6% in 2015, 10% in 2018 and 12.5% in 2021 and thereafter. Additionally, G.S. 62-133.8(d) requires that each utility satisfy its REPS requirement with solar energy based upon 0.02% of the utility's North Carolina retail sales beginning in the year 2010, 0.07% in 2012, 0.14% in 2015, and 0.20% in 2018 and thereafter. In its Order Clarifying Electric Power Suppliers' Annual REPS Requirements, issued on November 26, 2008, in Docket No. E-100, Sub 113, the Commission clarified that the calculation of these requirements for each year would be based upon the utility's North Carolina retail sales for the prior year. Additionally, the Commission has clarified that the swine and poultry waste set-aside requirements of G.S. 62-133.8(e) and (f) are aggregate obligations of the

[1] This does not apply to the information required to be filed annually pursuant to Rule R8-60(c)(1).

utilities. Mr. Smith testified that upon the passage of Senate Bill 3, Duke modified its consideration of renewable energy resources. Instead of screening such resources based on their economics, initial consideration is given to the level of renewable resources necessary for compliance with G.S. 62-133.8 and the Commission's rules. Public Staff witness Lucas testified that he believed that Duke should be able to meet its REPS requirements for the period covered by its plan, 2009-2011.

DNCP witness Reed presented testimony regarding the Company's 2009 REPS compliance plan filed with its 2009 IRP. Ms. Venable testified that the Company has been having difficulty obtaining poultry and swine renewable energy resources, but has been cooperating with the other IOUs in Docket No. E-100, Sub 113, to develop a solution. Public Staff witness Lucas testified that he believed that DNCP should be able to meet its REPS requirements for the period covered by its plan, 2009-2011.

PEC witness Fonvielle testified that based on experience to date and current assumptions, PEC's REPS plan is projected to achieve compliance with the REPS requirements. However, he noted that there are significant uncertainties that could adversely impact PEC's ability to meet the long-term REPS requirements. These uncertainties include undesignated future resources that may not materialize, as well as changes in the cost or availability of resources, especially set-aside resources. Mr. Fonvielle noted that since the filing of its 2009 REPS compliance plan, PEC had resolved issues involving its poultry waste set-aside and that it was actively pursuing meeting that requirement for 2012. Mr. Fonvielle testified that PEC's 2009 REPS compliance plan indicates that based on its projected requirements, EE, and contracted resources, PEC has enough resources to achieve compliance through 2013 and needs a minimum of an additional 170 gigawatt-hours to be in compliance in 2014. However, Mr. Fonvielle testified that based on current prices, the chances of PEC being able to reach Senate Bill 3's 12.5% goal in 2021 without reaching the price cap imposed by G.S. 62-133.8(h)(3) and (4) were not "so great" in the long term, though PEC's chances of meeting the goals in the early and mid-term were more favorable. He also stated that PEC was in good shape to meet its REPS goals through 2018 based on current expectations. Mr. Fonvielle expressed his hope that the development of a more competitive market would drive prices down and make the goals more achievable in the long term. Public Staff witness Lucas testified that he believed that PEC should be able to meet its REPS requirements for the 2009-2011 period covered by its plan.

Public Staff witness Ellis testified that unless the price of RECs drops considerably, meeting the REPS requirements beyond the short term could become challenging, as the IOUs may reach the caps in the near future. Mr. Ellis pointed out the fact that under Senate Bill 3, the cost caps do not rise as quickly as the REPS requirements. According to Mr. Ellis, this could create a situation where the utilities reach the cost caps before they meet the REPS goals.

CPI USA witness Reading testified that with the significant lead time required to build new renewable resources, he doubted whether PEC could meet the mandates of Senate Bill 3 in regard to in-state RECs. He pointed to the output of the facilities of CPI USA as a potential source for such in-state RECs, and noted the pending arbitration between his client and PEC over a PPA. Mr. Reading stated that while PEC's 2008 IRP listed cogeneration resources of 179 MW, these resources have been reduced to zero in PEC's 2009 IRP, indicating a less robust and balanced resource plan. Mr. Reading further testified that his calculations indicated that the most readily available resource by which PEC could meet its REPS requirement is biomass. He testified that PEC showed no deficit in renewable resources until 2014, and that PEC would have three years to attain those requirements. CPI USA's specific interest in this issue is the subject of a separate arbitration proceeding before this Commission in Docket No. E-2, Sub 966, and will be addressed by the Commission in that docket.

No party contended that the IOUs' REPS compliance plans for 2009-2011 were insufficient, but there was concern whether the IOUs could meet the REPS mandates through 2021 without reaching the cost caps. The Commission shares this concern and will closely monitor the utilities' compliance plans and their progress toward meeting each of the REPS requirements in the coming years.

The 2009 REPS compliance plans submitted in Docket No. E-100, Sub 124, completely supersede the 2008 REPS compliance plans submitted in Docket No. E-100, Sub 118. Therefore, the Commission has not made any determination as to the acceptability of the 2008 plans.

Based on the foregoing, the Commission's review of the 2009 REPS compliance plans, and the entire record of this proceeding, the Commission concludes that the 2009 REPS compliance plans submitted by the IOUs are reasonable for purposes of this proceeding and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The evidence supporting this finding of fact is contained in the testimony of, DNCP witness Venable, PEC witness Snider, and Public Staff witnesses Floyd and Hinton, and the 2009 IRPs of DNCP, PEC, and Duke.

Public Staff witness Floyd testified that the IOUs should utilize their DSM resources to obtain the maximum system value possible. He pointed out that while increased utilization of DSM might not lead to capacity savings, it might result in energy savings, with corresponding fuel savings. Mr. Floyd noted that both Duke and PEC received approval in 2009 for new residential air conditioning cycling programs that provide the capability to control central air conditioning systems in a manner that causes less customer inconvenience than earlier versions of such programs. He encouraged the IOUs to maximize the value of these air conditioning cycling programs. Similarly, Public Staff witness Hinton testified that while increased activation of these cycling programs should not have a material effect on the IOUs' expansion plans, it could allow the IOUs to achieve increased fuel savings during other near-peak or forced outage events. Mr. Hinton also pointed out that increased activation of these cycling programs could be beneficial to the utilities in that it would allow them to gain operational experience, test the program infrastructure, and assess customer response to more frequent power curtailments.

Mr. Floyd testified that he had compared Duke's Power Manager and PEC's EnergyWise air conditioning cycling programs with programs in other states and jurisdictions to some extent. He called PEC's and Duke's programs "new age" in that they involve new technology, but pointed to a program in Maryland that allows the customer to choose a level of incentive based on the amount of air conditioning load control he is willing to cede to the utility. Mr. Floyd deemed programs with various levels of incentives as a potential opportunity for consideration by North Carolina's IOUs.

DNCP witness Venable testified that DNCP included an air conditioner cycling program in its initial DSM portfolio modeled for the 2009 Plan and will consider opportunities for lowering fuel costs once the program is approved in North Carolina and it can further analyze operational data. PEC witness Snider testified that PEC will investigate and evaluate optimal use of its EnergyWise residential air conditioning load control program, including consideration of its potential benefits as a capacity resource and as a tool to lower fuel costs.

The Commission finds that DSM resources should be optimized so as to obtain their maximum value. Accordingly, the IOUs are encouraged in their 2010 IRPs to consider their DSM resources' potential benefits, both as capacity resources and as a means of lowering fuel costs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence supporting this finding of fact is contained in the Public Staff's comments filed on February 8, 2010, and the 2008 and 2009 IRP and 2009 REPS compliance plans of NCEMC, Piedmont, Blue Ridge, Rutherford, EU, Haywood, GreenCo, and Halifax.

On February 8, 2010, the Public Staff filed the only comments on the IRPs and REPS compliance plans filed by the non-IOU electric utilities. As part of its comments, the Public Staff addressed the IRPs filed by NCEMC, Piedmont, Rutherford, EU, and Haywood and the REPS compliance plans filed by GreenCo, Halifax, and EU in Docket No. E-100, Sub 124, pursuant to Rule R8-60.

The 2009 IRPs are, as described above, the annual updates to the 2008 IRPs. Therefore, consistent with Rule R8-60(h)(2), the Public Staff's comments addressed the non-IOUs' updated 15 year forecasts and significant amendments or revisions to their 2008 IRPs. The Public Staff's initial comments on the 2008 IRPs, filed April 24, 2009, and its reply comments filed May 27, 2009 (collectively, 2008 Comments), in Docket No. E-100, Sub 118 were incorporated by reference. Overall, the Public Staff found the IRPs and REPS compliance plans to be acceptable.

As noted in its comments, the Public Staff's analysis of NCEMC's peak load forecasting accuracy over the past five years indicates that the forecasts with DSM in its 2004 annual report were, on average, 332 MW lower than the actual system load, a 11% forecast error, whereas, its energy sales forecast has been more accurate with less than a 5% error rate. All of the peak load predictions from the 2004 Annual Plan have been less than the actual peak loads experienced. The Public Staff had noted this pattern of under-forecasting of peak loads in comments filed in previous IRP dockets. Since NCEMC does not weather normalize its peak loads, the Public Staff was unable to examine the accuracy of the forecasts excluding the effects of weather.

As it did in its comments in Docket No. E-100, Sub 118, the Public Staff continues to recommend that NCEMC examine its peak load forecasting models and assumptions for possible sources of bias leading to under-forecasting of peak loads, as well as other factors that may have contributed to the relatively large forecast errors. NCEMC is addressing this concern in two ways. First, it has informed the Public Staff that it intends to use a weather normalization methodology in its 2010 IRP. Second, NCEMC is evaluating other peak demand models. Both of these actions should assist NCEMC in improving its forecasting accuracy.

As noted on page 4 of its IRP, NCEMC completed a forecast in late 2009 that reflected the impact of the 2008/2009 economic recession. The new forecast indicates compound annual growth rates of 1.6% for summer peaks, 1.6% for winter peaks, and 1.3% for energy sales. The peak load forecasts are based on more current information than that available to NCEMC at the time of the filing of its 2009 IRP. The Public Staff believes NCEMC's updated forecast is more accurate in light of current conditions. Due to a lack of historical data, the accuracy of the forecasts of EU, Haywood, Piedmont, and Rutherford were not reviewed.

With the exception of Rutherford, the Public Staff believes the EMCs are developing new DSM/EE programs for their customers. Each EMC has continued to rely on its existing load control resources as its primary DSM/EE resources. The Public Staff was encouraged to see GreenCo develop a portfolio of DSM/EE resources that will be available to each of its participating members.

Based on the Public Staff's comments, and the Commission's review of the record in this proceeding, the Commission finds that the 2008 and 2009 IRPs and 2009 REPS compliance plans of NCEMC, Piedmont, Blue Ridge, Rutherford, EU, Haywood, GreenCo, and Halifax are reasonable and should be approved. The 2009 REPS compliance plans submitted in Docket No. E-100, Sub 124, completely supersede the 2008 REPS compliance plans submitted in Docket No. E-100, Sub 118. Therefore, the Commission has not made any determination as to the acceptability of the 2008 plans.

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 2008 biennial reports and the 2009 annual updates to the 2008 biennial reports filed in this proceeding by the IOUs, NCEMC, Piedmont, Blue Ridge, Rutherford, EU, and Haywood are hereby approved.

3. That the 2009 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 respective utility's projected reserve margins.

5. That future IRP filings by all utilities shall 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: (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. If time constraints dictate, this information may be filed separately from the main body of the 2010 report.

7. That the IOUs shall continue to investigate increased reliance on air conditioning cycling load control and other DSM resources so as to obtain the maximum value from those resources.

8. That NCEMC shall examine its peak load forecasting models and assumptions for possible sources of bias leading to under-forecasting of peak loads, as well as other factors that may have contributed to the relatively large forecast errors in the past.

9. 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), 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.

ISSUED BY ORDER OF THE COMMISSION.
This the 10th day of August, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

DOCKET NO. E-100, SUB 121

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	
Implementing a Tracking System for Renewable Energy Certificates Pursuant to Session Law 2007-397	) ORDER ADOPTING INTERIM) OPERATING PROCEDURES FOR) REC TRACKING SYSTEM

BY THE CHAIRMAN: On October 29, 2009, the Commission issued a Request for Proposals for the North Carolina Renewable Energy Tracking System (NC-RETS).

Subsequently, the Commission selected APX Inc., as the vendor to develop and administer NC-RETS. NC-RETS is scheduled to become operational on July 1, 2010.

APX requires written operating procedures to direct its administration of NC-RETS. The Commission's NC-RETS Stakeholder Group has been developing such operating procedures, and has resolved most, if not all, of the issues regarding those procedures.

WHEREUPON, the Chairman finds good cause to adopt the Interim Operating Procedures for NC-RETS attached to this order pending adoption by the Commission of final Operating Procedures. Proposed rule changes regarding implementation of Session Law 2007-397, including additional new rules addressing the renewable energy certificate (REC) tracking system, are pending before the Commission in this Docket as well as in Docket No. E-100, Sub 113. The Commission anticipates issuing an order regarding those rules shortly and allowing parties to comment as to whether there are any conflicts or inconsistencies between the proposed revised rules and the Interim Operating Procedures for NC-RETS. Following receipt of comments, the Commission anticipates issuing final Operating Procedures for NC-RETS.

IT IS, THEREFORE, ORDERED that the attached Interim Operating Procedures shall be adopted on an interim basis effective as of the date of this order and shall govern administration of NC-RETS until replaced by final Operating Procedures adopted pursuant to a subsequent Commission order.

ISSUED BY ORDER OF THE COMMISSION.
This the 1st day of July, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Patricia Swenson, Deputy Clerk

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DOCKET NO. E-100, SUB 124
DOCKET NO. E-100, SUB 125

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 124	)	
	)	
In the Matter of	)	
Investigation of Integrated Resource	)	ORDER REGARDING 2008
Planning in North Carolina – 2009	)	REPS COMPLIANCE REPORTS
	)	
DOCKET NO. E-100, SUB 125	)	
	)	
In the Matter of	)	
2009 REPS Compliance Plans	)	

BY THE COMMISSION: On February 29, 2008, and March 13, 2008, the Commission issued Orders in Docket No. E-100, Sub 113 adopting rules to implement Session Law 2007-397 (Senate Bill 3) and the Renewable Energy and Energy Efficiency Portfolio Standard (REPS) in North Carolina. Commission Rule R8-67(c)(1) provides as follows:

> 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.

For each electric public utility, the REPS compliance reports are to be filed at staggered times during the year and considered coincident with each utility's fuel adjustment clause rider. For each electric membership corporation (EMC) and municipal electric supplier, the REPS compliance report is required to be filed 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.

On or about September 1, 2009, the following EMCs filed REPS compliance reports for calendar year 2008 in Docket No. E-100, Sub 124: GreenCo Solutions, Inc.[1]; Halifax EMC; and Rutherford EMC. EnergyUnited EMC included information regarding its 2008 activities in its integrated resource plan filed in that docket. Also on or about September 1, 2009, the following EMCs and municipal electric suppliers filed REPS compliance reports for calendar year 2008 in

[1] GreenCo members include Albemarle EMC, Blue Ridge EMC, Brunswick EMC, Cape Hatteras EMC, Carteret-Craven EMC, Central EMC, Edgecombe-Martin County EMC, Four County EMC, French Broad EMC, Haywood EMC, Jones-Onslow EMC, Lumbee River EMC, Pee Dee EMC, Piedmont EMC, Pitt & Greene EMC, Randolph EMC, Roanoke EMC, South River EMC, Surry-Yadkin EMC, Tideland EMC, Tri-County EMC, Union EMC, and Wake EMC.

Docket No. E-100, Sub 125: North Carolina Eastern Municipal Power Agency (NCEMPA)[1]; North Carolina Municipal Power Agency Number 1 (NCMPA1)[2]; Fayetteville Public Works Commission (PWC); Murphy Electric Power Board; the cities of Concord and Kings Mountain; the towns of Black Creek, Dallas, Enfield, Forest City, Highlands, Lucama, Oak City, Pinetops, Sharpsburg, Stantonsburg, Waynesville, Windsor, and Winterville; Mountain Electric Cooperative, Inc.; Tri-State EMC; and Blue Ridge Mountain EMC. A number of EMCs and municipal electric suppliers indicated that they have signed wholesale power contracts with an electric power supplier that will also be providing REPS compliance service pursuant to G.S. 62-133.8(c)(2)(e), including the cities of Concord, Dallas, Kings Mountain and Wilson; the towns of Black Creek, Enfield, Forest City, Highlands Lucama, Pinetops, Sharpsburg, Stantonsburg, Waynesville and Windsor; Broad River EMC; and Rutherford EMC. Three municipal electric suppliers – the Towns of Fountain, Macclesfield and Walstonburg – and Mecklenburg EMC, which is headquartered in Virginia, did not file 2008 REPS compliance reports. Although the Towns of Macclesfield and Walstonburg are served by the City of Wilson which, in turn, purchases its power from NCEMPA, it is not clear whether NCEMPA has included these towns' loads in its REPS requirements. By letter dated April 14, 2010, Mecklenburg EMC stated that it intends to work with GreenCo to meet its REPS obligation.

Of those entities responsible for REPS compliance, either for themselves or others, several reported incurring significant costs to acquire renewable energy certificates (RECs) from renewable energy facilities or energy savings from the implementation of energy efficiency measures. Others reported that they had spent little, if any, money and had acquired few, if any, RECs in 2008.

With regard to the EMCs and municipal electric suppliers, the purpose of the annual hearing required in Rule R8-67(c)(3) is to verify the factual claims made regarding REPS compliance. The Commission recognizes that little is served at this time, prior to the initial REPS compliance year, by requiring EMCs or municipal electric suppliers that have earned or acquired few, if any, RECs or that have spent very little, if any, money to prove such claims. The Commission, therefore, will waive the hearing requirement and accept for filing the 2008 REPS compliance reports filed by those electric power suppliers. The 2008 REPS compliance reports filed by NCEMPA, NCMPA1, GreenCo, EnergyUnited EMC and Halifax EMC, however, claim substantial progress toward meeting the REPS requirements and/or raise important issues for consideration by the Commission. The Commission, therefore, finds good cause to issue separate orders opening new company-specific dockets to consider the 2008 REPS compliance reports filed by NCEMPA, NCMPA1, GreenCo, EnergyUnited EMC and Halifax EMC; to schedule hearings; to establish discovery guidelines and deadlines for the filing of testimony; and to require publication of notice. Lastly, any EMC or municipal electric supplier that has not filed a

[1] NCEMPA members include the towns of Apex, Ayden, Belhaven, Benson, Clayton, Edenton, Farmville, Fremont, Hamilton, Hertford, Hobgood, Hookerton, LaGrange, Louisburg, Pikeville, Red Springs, Robersonville, Scotland Neck, Selma, Smithfield, Tarboro, and Wake Forest, and the cities of Elizabeth City, Greenville, Kinston, Laurinburg, Lumberton, New Bern, Rocky Mount, Southport, Washington and Wilson.

[2] NCMPA1 members include the towns of Bostic, Cornelius, Drexel, Granite Falls, Huntersville, Landis, Maiden and Pineville, and the cities of Albemarle, Cherryville, Gastonia, High Point, Lexington, Lincolnton, Monroe, Morganton, Newton, Shelby and Statesville.

2008 REPS compliance report shall file its report or before September 1, 2010, together with its 2009 REPS compliance report.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 11th day of May, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Commissioners William T. Culpepper, III, and Lucy T. Allen did not participate in this decision.

Sw051010.01

DOCKET NO. SP-100, SUB 26

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Request for a Declaratory Ruling by	)	ORDER ON REQUEST FOR
BioEnergy Technologies, LLC	)	DECLARATORY RULING

BY THE COMMISSION: On August 18, 2010, BioEnergy (BioEnergy), filed a request for a declaratory ruling that organic waste material resulting from the rendering or processing of swine and poultry, when co-digested with swine and/or poultry manure, qualifies as "swine waste" or "poultry waste" for purposes of G.S. §§ 62-133.8(e) and 62-133.8(f), respectively. More specifically, BioEnergy plans to co-digest swine and/or poultry Dissolved Air Flotation cake sludge (DAF Cake) with swine manure and potentially other organic feedstocks at BioEnergy's planned North Carolina anaerobic digestion (AD) renewable biogas facilities. BioEnergy requested that all biogas derived from the co-digested poultry and/or swine DAF Cake and swine manure and associated renewable energy generated at the facilities qualify for the respective swine waste or poultry waste set-aside.

According to the petition, BioEnergy is a South Carolina limited liability company with its principal place of business in Sumter, South Carolina. It specializes in the design, construction and operation of AD biogas systems. In January 2010, Biogas entered into an exclusive licensing agreement with AAT Biogas (AAT), to capitalize on AAT's extensive technology and design experience in the biogas industry, which includes over 100 biogas reference projects in operation today. BioEnergy is actively evaluating a number of potential project opportunities in North Carolina and has entered into discussions with multiple North Carolina electric power suppliers about selling the electrical output and associated renewable energy certificates (RECs) generated at its planned biogas facilities. A BioEnergy facility would generate between 1.5 megawatts (MW) to 3.5 MW of electricity through the co-digestion of multiple feedstocks, in which BioEnergy currently plans to include DAF Cake from swine and/or poultry processing facilities, as well as manure from swine animal feeding operations located in close proximity to the animal processing plants. Other organic biomass also may be used to supplement these feedstocks, which BioEnergy recognizes would not qualify for the set asides, although they would qualify towards the general REPS compliance requirement.

In support of its request, BioEnergy stated that DAF Cake is an agro-industrial food processing waste comprised primarily of organic animal residues, such as fats and proteins, produced during the pre-treatment of the wastewater from meat and poultry processing facilities. The pre-treatment process is designed to capture the solid residuals content of a processing facility's effluent wastewater in the form of a waste sludge prior to the discharge of the wastewater to a downstream wastewater treatment facility. BioEnergy further stated that recent feasibility analysis suggests that an optimal co-digestion mix of DAF Cake from poultry and swine processing facilities and swine manure would include approximately twenty-five percent manure in order to provide micronutrients and the stabilization of the other, more energy dense, materials. This optimized mix can greatly increase methane production.

General Statute § 62-133.8(a), the definitional section of the Renewable Energy and Energy Efficiency Portfolio Standard (REPS) established by the General Assembly in Session Law 2007-397 (Senate Bill 3), defines "renewable energy resource", but does not define "swine waste" or "poultry waste." Similarly, the swine waste and poultry waste set-aside provisions, G.S. §§ 62-133.8(e) and 62-133.8(f), respectively, do not define what constitutes swine or poultry waste resources, except that G.S. § 62-133.8(f) expressly recognizes that, for purposes of the statute, poultry waste may be combined with other organic materials, specifically, "wood shavings, straw, rice hulls, or other bedding material."

BioEnergy argued that the plain meaning of "swine waste" and "poultry waste" includes all types of waste derived from swine or poultry, citing *Merriam-Webster's Online Dictionary*, which defines waste to include both an "unwanted by-product of a manufacturing process," as well as "refuse from places of human or animal habitation." Consistent with this common and plain meaning of the term, BioEnergy further argued, agro-industrial waste, such as DAF Cake, should also qualify as waste under North Carolina's Solid Waste statute. G.S. § 130A-290. Thus, BioEnergy argued, the plain language of the term "waste" as used in G.S. §§ 62-133.8(e) and 62-133.8(f), should be interpreted to include both agro-industrial processing waste, such as DAF Cake, as well as manure from animal feeding operations.

BioEnergy further asserted that interpreting swine waste and poultry waste to include agro-industrial DAF Cake also would further the renewable policy objectives of Senate Bill 3 by diversifying the State's viable generation resource options, allowing the utilization of indigenous North Carolina resources to foster development of renewable projects locally in the State, encouraging project investment in new renewable projects, and improving air and water quality through controlled destruction of methane and the capture of organic residuals from both manure and agro-industrial wastes. By recognizing DAF Cake derived from swine or poultry processing facilities as eligible "swine waste" or "poultry waste," BioEnergy argued that the Commission will encourage the increased use of both manure and DAF Cake as renewable feedstocks, thereby promoting the development of renewable biogas projects and supporting greater diversity of indigenous renewable generation resources used to comply with the REPS and the swine and poultry waste set asides. In addition to the State's tremendous swine and poultry growing industries, BioEnergy asserted that North Carolina also is one of the leading animal processing states in the nation.

BioEnergy also argued that interpreting "swine waste" and "poultry waste" to allow methane and energy derived from co-digested DAF Cake and manure to qualify for the REPS set-asides will assist electric power suppliers in achieving their set-aside requirements in a more cost effective manner. According to BioEnergy, allowing dense DAF Cake to be combined with manure will result in increased methane yields and energy generation at lower costs. This, in turn, will make an increasing number of biogas projects viable thereby fostering competition and driving down compliance costs for electric power suppliers. Satisfying the set-asides at lower cost would then also facilitate increased opportunities for additional renewable energy generation to satisfy the general REPS requirement and, potentially, lower overall costs to ratepayers.

The Commission has held, specific to AD biogas technology, that only RECs associated with the percentage of electric generation that results from methane gas that was actually produced by poultry or swine waste may be credited toward meeting the set-aside requirements. *Order on Motion for Clarification*, Docket No. E-100, Sub 113, January 20, 2010, at p. 2. The Commission made clear that, when non-swine or non-poultry waste biomass materials contribute to some portion of methane gas production at a facility, RECs attributable to that methane gas will not count toward meeting the poultry or swine waste set-asides. The obligation is on the owner of the new renewable energy facility to demonstrate the percentage of biogas attributable to swine or poultry waste versus the percent derived from other biomass resources. *Order Accepting Registration of New Renewable Energy Facility*, Docket No. SP-578, Sub 0. BioEnergy stated that it would provide the Commission with evidence of the percentage of biogas attributable to swine waste and/or poultry waste versus the percent derived from other biomass. According to the filing, in BioEnergy's process, each feedstock material will be weighed as it is loaded into the mixing tank/digester. Because each feedstock has bio-methane yields that have been established and verified by lab tests, BioEnergy asserted that the percentage of biogas attributable to each type of feedstock can and will be reasonably calculated.

On August 27, 2010, the North Carolina Sustainable Energy Association (NCSEA) filed a motion to intervene and asked that the matter be set for hearing. Following several discussions between NCSEA and BioEnergy and a meeting of the parties, BioEnergy filed on October 4, 2010, the affidavit of Marvin K. Ballard, III, BioEnergy's Business Development Manager. The affidavit stated that BioEnergy had responded to questions from NCSEA regarding the specific composition of DAF Cake and related issues and that the purpose of the affidavit was to provide the additional information for the record. In light of the above, NCSEA informed the Public Staff that it did not object to a declaratory ruling consistent with BioEnergy's request.

The Public Staff presented this matter to the Commission at its Regular Staff Conference on October 11, 2010, and recommended that the Commission declare that, based upon the facts and representations contained in BioEnergy's request and affidavit, (a) swine and/or poultry DAF Cake, when co-digested with swine or poultry manure, qualifies as "swine waste" or "poultry waste" for purposes of G.S. §§ 62-133.8(e) and 62-133.8(f), respectively, and (b) the electric power generated by the biogas derived from the swine and/or poultry DAF Cake, when co-digested with swine and/or poultry manure, qualifies for the respective swine waste and poultry waste set-aside in proportion to the percentage of biogas attributable to swine waste and to poultry waste.

Based upon the foregoing, a careful consideration of the record in this docket, and the Public Staff's recommendation, the Commission concludes that, based upon the facts and representations in BioEnergy's request and affidavit, (a) swine and/or poultry DAF Cake, when co-digested with swine or poultry manure, qualifies as "swine waste" or "poultry waste" for purposes of G.S. §§ 62-133.8(e) and 62-133.8(f), respectively, and (b) the electric power generated by the biogas derived from the swine and/or poultry DAF Cake, when co-digested with swine and/or poultry manure, qualifies for the respective swine waste and poultry waste set-asides as more specifically ordered herein.

IT IS, THEREFORE, ORDERED that, based upon the facts and representations made in BioEnergy's request and affidavit, (a) swine and/or poultry DAF Cake, when co-digested with swine or poultry manure, qualifies as "swine waste" or "poultry waste" for purposes of G.S. §§ 62-133.8(e) and 62-133.8(f), respectively, and (b) the electric power generated by the biogas derived from the swine and/or poultry DAF Cake, when co-digested with swine and/or poultry manure, qualifies for the respective swine waste and poultry waste set-aside in proportion to the percentage of biogas attributable to swine waste and to poultry waste, as demonstrated by BioEnergy through the weighing of each feedstock material and the verification of each feedstock's bio-methane yield.

ISSUED BY ORDER OF THE COMMISSION.
This the 12th day of October, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Pb101210.01

DOCKET NO. P-100, SUB 19
DOCKET NO. P-100, SUB 168

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. P-100, SUB 19

In the Matter of Rules to Require Regulated Telephone Companies to File Construction and Operating Budgets DOCKET NO. P-100, SUB 168 In the Matter of Filing Requirement for the Central Office Equipment Report as Required by Standing Data Request of Uncertain Origin	)	ORDER RESCINDING COMMISSION RULE R9-3 AND ELIMINATING FILING REQUIREMENT FOR CENTRAL OFFICE EQUIPMENT REPORT FOR ALL LOCAL EXCHANGE COMPANIES

BY THE COMMISSION: On June 30, 2009, House Bill 1180 became law as set forth in Session Law 2009-238 (hereinafter S.L. 238). Entitled "An Act Establishing The Consumer Choice And Investment Act Of 2009", the law creates a new category of price plan which any local exchange carrier (LEC) or competing local provider (CLP) may opt into by simply "filing notice of its intent to do so with the Commission". The election is effective immediately upon filing. The Commission refers to these new price plans in general as "Subsection (h) price plans".

On July 21, 2009, the Commission issued an Order Requesting Comments and Instituting Certain Interim Requirements in Docket No. P-100, Sub 165 wherein the Commission began the process of determining an orderly procedure for carriers to follow when adopting a Subsection (h) price plan and addressing further implications of S.L. 238. In its July 21, 2009 Order, the Commission noted that Commission rules, statutes, notice, and reporting obligations may be impacted by S.L. 238. The Commission noted that, while rules and statutes are the most salient items affected by the passage of S.L. 238, there are also orders that the Commission has issued over the years that have imposed notice obligations and reporting requirements on LECs that may be affected by a Subsection (h) election. The Commission determined that it was appropriate to solicit comments from parties setting forth those statues, Commission rules, notice, and reporting obligations that they believe will no longer be in force for a LEC or CLP in such circumstances, together with the reasons therefore.

On October 20, 2009, the Commission issued its Order Implementing Certain Requirements in Docket No. P-100, Sub 165. In its October 20, 2009 Order, the Commission concluded, after reviewing the initial and reply comments filed by the parties in response to the July 21, 2009 Order, that the Public Staff and the other commenting parties to the docket should be directed to address this issue, and, to that end, should be constituted as a Working Group[1] to develop a matrix that: (a) addresses which statutes, Commission rules, and notice and reporting obligations will no longer be in force for a company electing a Subsection (h) price plan; (b) suggests any necessary changes to those rules or notice and reporting obligations; and (c) sets out any differing positions and the rationales therefore. The Commission further stated that the parties may also address in the matrix any issues that they have come to believe are relevant, necessary, and convenient for Commission decision. The parties were directed to file such a matrix by no later than 45 days from the issuance of the October 20, 2009 Order.

After being granted two extensions of time to file, on February 2, 2010, the Working Group filed its Report and Matrix.

On March 30, 2010, the Commission issued its Order Concerning Working Group Report in Docket No. P-100, Sub 165. The Commission noted that two specific issues were outside the scope of the March 30, 2010 Order but stated that the issues would be addressed by the Commission in the context of another docket. The purpose of this Order is to address the two outstanding issues from the March 30, 2010 Order.

First, in its March 30, 2010 Order, the Commission outlined the Working Group's Matrix presentation of Issue No. 37, as follows:

> Rule R9-3 – Annual Filing of Construction Plans and Objectives by Telephone Companies
>
> Working Group Position for Subsection (h) entities:
>
> (i) Subsection (h) entities should be exempted.
>
> (ii) Rule should be eliminated for Subsection (h) and **all other LECs**.
>
> The NCTIA and the Public Staff agreed with the Working Group's position.
>
> CompSouth did not take a position on the continued need for this requirement at this time.

The Commission concluded in its March 30, 2010 Order that Docket No. P-100, Sub 165 was not the appropriate proceeding to eliminate the applicability of Rule R9-3 for rate-of-return LECs[2], as contemplated by the Working Group's position on Issue No. 37 which states that the

[1] The members of the Working Group include: the Public Staff, The North Carolina Telecommunications Industry Association, Inc. (NCTIA), and the Competitive Carriers of the South, Inc. (CompSouth). CompSouth's members include: Access Point Inc.; Birch Communication (f/k/a ACCESS Integrated Networks, Inc.); Cavalier Telephone; Cbeyond Communications; Covad Communications Company; Deltacom, Inc.; Level 3 Communications; NuVox Communications, Inc.; tw telecom of north carolina l.p.; and XO Communications, Inc.

[2] By Order dated May 14, 2007, in Docket No. P-100, Sub 19A, the Commission exempted price regulation plan LECs from Rule R9-3.

rule should be eliminated for Subsection (h) and all other LECs. The Commission stated that it would address this change in the context of another docket.

By this Order, the Commission is eliminating the applicability of Rule R9-3 for rate-of-return LECs. Since, with the adoption of this change, no telecommunications companies would continue to be required to adhere to Rule R9-3, the Commission is rescinding Rule R9-3 in its entirety from its official set of Commission Rules, effective on the date of this Order.

Second, in its March 30, 2010 Order, the Commission noted that, for Issue No. 88, item (i), the Working Group's position was that the filing requirement for the Central Office Equipment Report, required by a standing data request of uncertain origin, should be eliminated for all Subsection (h) entities and all other LECs. The Commission concluded in its March 30, 2010 Order that eliminating the filing requirement for all other LECs was outside the scope of Docket No. P-100, Sub 165; the Commission stated that it would address this change in the context of another docket.

The Commission finds it appropriate to eliminate the filing requirement for the Central Office Equipment Report for all LECs. The LECs are responsible for continuing to have such information available in the event the Commission or the Public Staff requests such information, such as in the case of verification of UNE Zone status under the Federal Communications Commission's UNE rules.

IT IS, THEREFORE, ORDERED as follows:

1. That Commission Rule R9-3 (Annual Filing of Construction Plans and Objectives by Telephone Companies) is rescinded in its entirety as of the date of this Order; and

2. That the filing requirement for the Central Office Equipment Report for all LECs is hereby eliminated. The LECs are responsible for continuing to have such information available in the event the Commission or the Public Staff requests such information, such as in the case of verification of UNE Zone status under the Federal Communications Commission's UNE rules.

ISSUED BY ORDER OF THE COMMISSION.
This the 9th day of April, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

bp040810.01

DOCKET NO. P-100, SUB 133f

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Lifeline and Link-Up Services Pursuant to Section 254 of the Telecommunications Act of 1996	)))	ORDER REQUIRING SELF-CERTIFICATION

BY THE COMMISSION: On January 15, 2010, the Lifeline/Link-Up Task Force (Task Force)[1], in compliance with the Commission's *Order Requesting Further Study to Adopt Lifeline/Link-Up Program Expansion,* submitted its semi-annual report to the Commission. The report reflects the ongoing efforts of the Task Force to track and expand the level of participants in the Lifeline/Link-Up Program.

BACKGROUND

Lifeline is a federal and state funded program that provides North Carolina's low-income residents a discount of $13.50 per month[2] on their local telephone bill. Link-Up is a federally funded program that provides North Carolina's low-income residents a fifty percent discount, up to $30.00, on the cost of connecting local telephone service. The main objective of both programs is to promote the availability of local telephone service to North Carolina's low-income residents. In 1998, the Task Force was formed for the purpose of ensuring that the programs were implemented in an effective manner and for exploring ways in which North Carolina residents could be better informed regarding the existence of the programs.

Presently, North Carolina residents are eligible for Lifeline/Link-Up if they receive Supplemental Security Income (SSI), Food Stamps[3], Work First, Temporary Aid to Needy Families or TANF, Medicaid, the Low Income Home Energy Assistance Program (LIHEAP), or Section 8 Federal Public Housing Assistance benefits.

The Task Force has also has been active in increasing awareness of and participation in Lifeline/Link-Up through a variety of means. In an Order issued on April 10, 2008, the Commission approved a self-certification pilot program to be conducted by AT&T.

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[1] The Lifeline/Link-Up Task Force unofficially consists of representatives of the Attorney General's Office, N.C. Division of Social Services (NCDSS), N.C. Division of Medical Assistance (NCDMA), Windstream Communications, Inc., BellSouth Telecommunications, Inc. d/b/a AT&T North Carolina, Public Staff, Social Security Administration (SSA), N.C. Justice Community Development Center (NCJCDC), Sprint d/b/a Embarq Communications, Randolph Telephone Membership Corporation (Randolph TMC), N.C. Division of Information Resource Management (NCDIRM), and Verizon South, Inc.

[2] The Lifeline discount of $13.50 is composed of a $10.00 federal subsidy and a $3.50 NC income tax credit.

[3] Sometimes referred to as Food Nutrition Services or FNS.

TASK FORCE ANALYSIS AND RECOMMENDATIONS

On January 15, 2010, the Task Force filed its annual report with recommendations. The Task Force reported that, based on reports filed by local telephone providers as of December 31, 2009, there were 155,585 households receiving Lifeline benefits. Also, during the period of July 1, 2009 through December 31, 2009, there were 46,648 households that received Link-Up discounts for the cost of connecting telephone service.[1] In the June 2009 Task Force report, there were 141,112 Lifeline recipients and 16,069 households that received Link-Up discounts.

The Task Force also reported on AT&T's self-certification pilot project, as well efforts to implement a streamlined enrollment procedure for recipients of Food Stamps. The Task Force recommended that the Commission adopt self-certification as the means by which all jurisdictional local providers enroll participants in the Lifeline/Link-Up program. Additionally, the Task Force reported on its efforts to increase awareness of with Lifeline/Link-Up benefits through the placement of posters in county Department of Social Services (DSS) offices throughout the state.

The Task Force recounted that, following the April 10, 2008 Order, which approved the addition of federal public housing, AT&T had begun the self-certification pilot program which had been earlier approved by the Commission.[2] The Task Force stated that customers who contacted AT&T for information on the Lifeline/Link-Up program were sent the self-certification form, and, upon receipt of the completed and signed form, the customer was added as a Lifeline recipient.

The Task Force noted that AT&T filed a report with the Commission on June, 5, 2009, in which AT&T reporting that during the first year of the pilot program, approximately 99% of its new Lifeline/Link-Up applicants used the self-certification form. Also, the monthly average of AT&T Lifeline applicants increased by about 20% during the pilot program and the average of Link-Up applicants increased approximately 40%. AT&T did not report any increase in instances of fraud or misrepresentation by Lifeline/Link-Up applicants.

Furthermore, AT&T adopted an audit process in which AT&T periodically would send letters and self-certification forms to a representative sample of Lifeline participants to verify continued eligibility to receive Lifeline benefits. If the self-certification form was not returned to AT&T within 60 days, or if it is returned stating that the consumer was no longer eligible for a qualifying program, then AT&T removed the consumer from participation in the Lifeline program. The Task Force stated that this review procedure is acceptable under the Federal Communications Commission's (FCC's) guidelines and AT&T found it to work well.

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[1] Statistics for the six-month period ended December 31, 2009, had not been filed by all local telephone providers at the time of this report.

[2] Order Concerning Task Force Report and Authorizing Pilot Program, Docket No. P-100, Sub 133f, (September 5, 2007).

AT&T reported that it found the self-certification process to be more cost effective than processing applications under the existing system. AT&T uses self-certification in all of its southeastern states, and it said that its positive findings were consistent with its experience in the other southeastern states.

The Task Force formed a subcommittee to study whether the self certification procedure should be adopted as the sole or primary Lifeline/Link-Up application procedure to be used by all local service providers. The subcommittee reported to the Task Force's meeting on December 10, 2009, presenting the following observations:

- The Task Force examined whether the costs impact to smaller service providers for administrative changes and employee retraining would be outweighed by the operational savings going forward. The Task Force concluded that there were long-term benefits in staff time saved by the streamlined application and review procedure. Accordingly, the Task Force concluded that such long-term benefits would outweigh the costs incurred by smaller providers.
- The Task Force addressed whether a standardized self-certification form should be used by all the service providers. A draft form was developed and submitted with the Task Force's semi-annual report. The Task Force stated that several changes were made to the form used by AT&T to include a list of the names and addresses of all non-cellular Lifeline/Link-Up telephone providers on the back of the form, adding a phrase explaining that only one Lifeline benefit is available per household, and adding the sentence that long distance call blocking is available to Lifeline recipients at no charge upon request.
- The Task Force reported that it discussed whether potential applicants would have enough information about Lifeline/Link-Up and the self-certification procedure to enable them to file a proper application with their telephone service provider. The Task Force concluded that the adoption of the self-certification procedure for Lifeline-Link-Up benefits should have no impact on information availability to the public. The Task Force pointed out that there would be no change in the program information provided by DSS caseworkers once an applicant for Medicaid, Food Stamps or other qualifying benefits is found eligible. The local telephone service providers and the Task Force will continue publicizing Lifeline/Link-Up in the same manner. The only change will be the use of self-certification to enroll in the program.
- The Task Force recommended that if self-certification is adopted as the sole procedure for enrolling Lifeline/Link-Up participants, the Commission should also approve the use of the above described self-certification eligibility review process by the local telephone service providers. Using self-certification and the current system for enrolling applicants would be confusing and a waste of resources. Accordingly, the Task Force stated that it unanimously recommended that the Commission adopt the self-certification procedure as the sole method to enroll consumers in the Lifeline/Link-Up program and approve the use of the above described self-certification eligibility review process by all local telephone service providers.

The Task Force noted that the Commission has had an ongoing interest in increasing participation among eligible consumers to receive Lifeline-Link-Up benefits. To do so, the

Commission earlier approved a self-certification pilot project, which was undertaken by AT&T and subsequently reported as successful, as well as cost-justified. The Task Force reported that after the successful completion of the self-certification pilot program by AT&T, it formed a subcommittee to investigate the adoption of self-certification for use by all local service providers. There were two concerns of whether to adopt a self-certification procedure for clients to receive Lifeline/Link-Up benefits: (1) the cost to implement a self-certification program, especially among the smaller local telephone service providers; and, (2) the adoption of a standard procedure, to include a self-certification form and an on-going account verification procedure.

The Task Force stated that the cost to implement the self-certification procedure to eligible consumers to receive Lifeline/Link-Up benefits was reasonable in that gains from programmatic operational efficiencies would outweigh the on-going operational expenses to support the self-certification procedure, even for the smaller local telephone service providers. The Task Force also believed that there were long-term benefits in staff time saved by the streamlined application and review procedure.

The Task Force included a recommended self-certification form to be used for the program by all local service providers. The proposed self-certification form, a modified form used in the AT&T pilot program, would also include a listing of all wire line local telephone service providers who provide Lifeline/Link-Up benefits. Furthermore, the Task Force stated that the Commission should adopt the self-certification procedure as the sole method to enroll consumers in the Lifeline/Link-Up program and approve the use of the above described self-certification eligibility review process by all local telephone service providers. The verification of eligibility for recipients to continue receiving Lifeline discounts would be adopted from the AT&T pilot, in which, AT&T periodically would send letters and self-certification forms to a representative sample of Lifeline participants to verify continued eligibility to receive Lifeline benefits. If the self-certification form was not returned to AT&T within 60 days, or if it is returned stating that the consumer was no longer eligible for a qualifying program, then AT&T removed the consumer from participation in the Lifeline program.

In addition, the Task Force believed that there should be no change in the program information provided by DSS caseworkers once an applicant for Medicaid, FNS or other qualifying benefits is found eligible. The local telephone service providers and the Task Force will continue publicizing Lifeline/Link-Up in the same manner, with the only change being how consumers are enrolled in the program.

WHEREUPON, the Commission reached the following

CONCLUSIONS

After careful consideration, the Commission concludes that good cause exists to modify the certification process for eligibility for the Lifeline/Link-Up program so as to allow self-certification by recipients.[1] The Commission believes that, based on the representations of the Task Force, the AT&T self-certification experiment has been a success, combining greater

[1] This includes modification of Rule R9-6(d) concerning verification by the appropriate social service agency.

efficiency with appropriate protections against fraud, and that, therefore, the same self-certification process should be generally adopted as part of the Lifeline/Link-Up enrollment process. The Commission commends the work of the Task Force, AT&T, and the various social service agencies for their contributions to improving delivery of the Lifeline/Link-Up program to qualifying recipients. The Commission urges the Task Force to continue with its efforts to improve the Lifeline/Link-Up program.

IT IS, THERFORE, ORDERED as follows:

1. That self-certification by clients of eligible programs for Lifeline/Link-Up be authorized as the sole procedure for enrollment in Lifeline/Link-Up.

2. That the self-certification form attached as Appendix A be authorized for use by clients of eligible programs for Lifeline/Link-Up. The listing of eligible telephone companies on that form may be modified from time to time to accurately reflect the companies' participation.

3. That the eligibility review audit process utilized by AT&T in the self-certification pilot program be made permanent for AT&T and be extended to and required of all other telephone companies participating in the provision of the Lifeline/Link-Up program.

4. That Rule R9-6(d), regarding Link-Up verification be rewritten as follows: "(d) Verification – The method for verification of the eligibility criteria set forth in (c)(2) shall be self-certification by the recipients of the eligible programs."

5. That the Task Force collect the same type of statistical data it collected for the AT&T Pilot Program from the various participating telephone companies and submit an analysis regarding same with the Task Force's December 31, 2010, Annual Report, together with any recommendations the Task Force believes are needed to improve the sign-up and verification process.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 2nd day of March, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

mr030210.01

APPENDIX A
PAGE 1 OF 2

NORTH CAROLINA LIFELINE/LINK-UP
SELF-CERTIFICATION LETTER

Billing Name ______________________________

Service Address ______________________________

City State Zip ______________________________

Telephone Number: ______________________________

I hereby certify that I participate in the following public assistance program(s):

( ) Medicaid
( ) Low Income Home Energy Assistance Program (LIHEAP)
( ) Federal Public Housing Or Section 8 Assistance (FPHA)
( ) Supplemental Security Income (SSI)
( ) Food & Nutrition Services (Food Stamps)
( ) Temporary Aid to Needy Families or *Work First*

Lifeline provides a monthly discount on your local telephone bill. If you do not have a telephone, Link-Up provides a 50% discount, up to $30, on the cost of connecting local telephone service. If you receive any one of the public benefits listed above and the telephone service is in your name, then you can receive Lifeline/Link-Up benefits. Only one Lifeline benefit is available per household. Long distance call blocking is available to Lifeline recipients at no charge upon request.

I certify, under penalty of perjury, that I am a current recipient of the above program(s) and will notify my telecommunications service provider when I am no longer participating in at least one of the above-designated program(s). I authorize my telecommunications service provider or its duly appointed representative to access any records required to verify these statements to confirm my continued participation in the above program(s). I authorize representatives of the above program(s) to discuss with/or provide copies to my telecommunications service provider, if requested by the company to verify my participation in the above program(s) and my eligibility for Lifeline/Link-Up.

______________________________ ______________
Applicant's signature Date

Please mail completed self-certification form to your telecommunications service provider at the address shown on the back of this form

APPENDIX A
PAGE 2 OF 2

Affordable Phone Services, Inc 2855 SE 58th Ave Ocala, FL 34480	Aspire Telecom, Inc P.O. Box 2174 Asheville, NC 28802	Atlantic Telephone Membership Corp P.O. box 3198 Shallotte, NC 28459
AT&T RSC 304 Pine Avenue, 4th Floor Albany, GA 31702	Barnardsville Telephone Company P.O. Box 22995 Knoxville, TN 37933-0995	BLC Management LLC 11121 Highway 70, Suite 202 Arlington, TN 38002
Budget Prepay, Inc, d/b/a NewPhone 1325 Barksdale Blvd. Bossier City, LA 71111	CenturyLink Attn: Lifeline P. O. Box 4918 Monroe, LA 71211	Citizens Telephone Company P.O. Box 470 Rock Hill, SC 29730
dPi-Teleconnect, L.L.C 2997 LBJ Freeway Suite 225 Dallas, TX 75234	Ellerbe Telephone Company P.O. Box 220 Ellerbe, NC 28338-0220	Image Access, Inc 5555 Hilton Avenue, #415 Baton Rouge, LA 70808
Lexcom Telephone Company 200 North State Street P.O. Box 808 Lexington, NC 27293-0808	Lifeconnex Telecom, LLC f/k/a Swiftel, LLC 811 West Garden St Pensacola, FL 32507-7475	MCImetro Access Trans 5055 North Point Parkway 2nd Floor Alpharette, GA 30022
Mebtel, Inc C/O Century Tel 19812 Underwood Rd Foley, AL 36535	Nexus Communications, Inc C/O Early, Lennon, Crocker 900 Comerica Bldg Kalamazoo, MI 49007-4752	North State Telephone Company P.O. Box 2326 High Point, NC 27261
Pineville Telephone Company P.O. Box 249 Pineville, NC 28134	Randolph Telephone Company 3733 Old Cox Rd Asheboro, NC 27205	Randolph Telephone Membership Corporation 3733 Old Cox Road Asheboro, NC 27205
Saluda Mtn Telephone Company P.O. Box 22995 Knoxville, TN 37933-0995	Service Telephone Company P.O. Box 22995 Knoxville, TN 37933-0995	Skyline Telephone Membership Corporation P.O. Box 759 West Jefferson, NC 28694
Star Telephone Membership Corporation P.O. Box 348 Clinton, NC 28329	Surry Telephone Membership Corporation P.O. Box 385 Dobson, NC 27017-0385	Tennessee Telephone Services, LLC P.O. Box 1995 Dickson, TN 37056
Tri-County Telephone Membership Corporation P.O. Box 520 Belhaven, NC 27810	Verizon Lifeline Services - NC Attn: Lifeline Supervisor P. O. Box 4500 Hayden, ID 83835-4500	Wilkes Telephone Membership Corporation 1400 River Street Wilkesboro, NC 28697
Windstream ATTN : Support Services – Lifeline 1720 Galleria Boulevard Charlotte, NC 28270	Yadkin Valley Telephone Membership Corporation P.O. Box 368 Yadkinville, NC 27055	

DOCKET NO. P-100, SUB 152b

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Notices Regarding Termination of Universal Service Provider Status	)))	ORDER DESIGNATING TWC DIGITAL PHONE LLC AS USP FOR POWELL PLACE

BY THE COMMISSION: On November 13, 2009, Madison River Communications, LLC (MRC) filed a letter in connection with the carrier of last resort (COLR) status of the Powell Place development in the Pittsboro exchange, seeking relief from its COLR obligations. MRC noted that on July 28, 2006, it had notified the Commission that it had accepted COLR responsibilities for Powell Place, but it has since learned that Powell Place has entered into an agreement with Time Warner, and local service for residents of this development is now being provided by Time Warner. MRC is no longer providing service and has no infrastructure in this development.

On November 20, 2009, the Commission issued an Order Seeking Comments from "Embarq, Time Warner Cable, Inc. and TWC Digital Phone LLC, and the Public Staff" by December 16, 2009.

COMMENTS

Carolina Telephone and Telegraph LLC d/b/a CenturyLink (CT&T)[1] stated that it is the incumbent local exchange carrier (ILEC) in the Pittsboro exchange, which encompasses Powell Place. CT&T supports terminating MRC's designation as universal service provider (USP) in the Powell Place subdivision. CT&T supports continuing to designate "the current provider of telecommunications service in the subdivision" as the USP. CT&T further explained that it had not been the USP in Powell Place for several years, ever since MRC had accepted COLR responsibilities for the subdivision. CT&T neither has infrastructure nor provides service to Powell Place, and it would be inequitable and unduly burdensome to redesignate CT&T as the USP there. By contrast, Time Warner appears to have stepped into MRC's shoes to provide such service. To designate Time Warner as the USP would be consistent with Commission precedent.[2]

Public Staff, while disclaiming knowledge of the circumstances surrounding the apparent change in the local service provider, suggested that this situation may be similar to that

[1] CT&T noted that, while the Commission's Order requested comment from "Embarq," as of July 1, 2009, Embarq Corporation had merged with CenturyTel, Inc. (CenturyTel). As of October 19, 2009, the combined company began using the unified brand name of "CenturyLink." Furthermore, through this transaction, MRC—a legacy CenturyTel company—is now affiliated with the former Embarq ILECs in North Carolina, including CT&T.

[2] See the Order *In the Matter of Petition of Shentel Converged Services, Inc. to Surrender Authority to Provide Telecommunications Services in a Certain Geographical Area,* Docket No. P-1422, Sub 2 (October 31, 2008) (*Shentel*).

in the *Shentel* case. The Public Staff reiterated its belief that it is consistent with the law and in the public interest that every region, areas, subdivision, and customer have a designated USP.

Time Warner Entertainment-Advance/ Newhouse Partnership and TWC Digital Phone, LLC (collectively, TWC) stated that it is currently a party to an agreement, effective June 1, 2009, to provide multi-channel video, high-speed data, telephone, and certain additional services to the residents of the Powell Place development at 104 Powell Place Lane, Pittsboro, North Carolina. The telephone service is interconnected Voice-over-Internet Protocol (VoIP) and is branded by TWC as "Digital Phone." TWC has articulated its view in previous proceedings that the shifting of the USP responsibility to it is inappropriate as a matter of state and federal law. TWC further contended that, in the context of the present proceeding, it is not necessary for the Commission to redesignate a new USP for Powell Place.

Nevertheless, TWC acknowledged that, pursuant to its agreement currently in place with Powell Place, it has the ability to and will provide Digital Phone service to any residential customer in Powell Place development desiring such service. Specifically, this commitment is to offer Digital Phone service, as that service is offered to the public by TWC, to residential customers in the Powell Place development for so long as TWC's contract with Powell Place remains in place and consistent with the terms of that contract, at rates equivalent to publicly available rates for Digital Phone service in that area. TWC stated that this acknowledgement is without waiver of any rights with respect to the regulatory status of Digital Phone service and/or the applicability of state or federal rules to this service. For example, TWC currently does not participate in the Lifeline and Link-Up programs; and, accordingly, such benefits will not be available as a component of TWC's provision of Digital Phone service to Powell Place.

Notwithstanding the foregoing acknowledgements, TWC stated that, should the Commission conclude that redesignation of a USP for the Powell Place development is appropriate or required under the facts presented in this proceeding, TWC Digital Phone LLC would consent to such a designation consistent with the stipulations set forth in the Commission's *Shentel* Order.

WHEREUPON, the Commission concludes that good cause exists (1) to relieve MRC of its COLR obligations with respect to the Powell Place subdivision in the Pittsboro exchange and (2) to designate TWC Digital Phone LLC as the USP in its stead subject to the provisions set forth in Appendix A, which are identical in substance to the stipulations set forth in the *Shentel* Order.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 5th day of January, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

DI010510.01

APPENDIX A

(1) TWC Digital Phone LLC is designated the "universal service provider" for the Powell Place subdivision in the Pittsboro Exchange, North Carolina. Pursuant to this designation, TWC Digital Phone LLC will provide Digital Phone service to any residential customer in the Powell Place Subdivision desiring such service. Specifically, TWC Digital Phone LLC will offer Digital Phone service, as that service is offered to the public, to any residential customer in Powell Place Subdivision for so long as Time Warner Cable's existing contract to provide service in the Powell Place subdivision remains in place, at rates equivalent to publicly available rates for Digital Phone service in the Pittsboro, North Carolina area. TWC Digital Phone LLC currently does not participate in the Lifeline and Link-Up programs; accordingly, such benefits will not be available as a component of the provision of Digital Phone service to the Powell Place subdivision.

(2) The designation of TWC Digital Phone LLC as the universal service provider for the Powell Place subdivision does not constitute an assertion by the Commission of jurisdiction over TWC Digital Phone LLC for any other purpose and is without prejudice to TWC Digital Phone LLC's position that Digital Phone is not subject to regulation by the Commission under Chapter 62 of the General Statutes and that the Commission's rules and regulations relating to telephone service provided by public utilities are not applicable to this service.

(3) The designation of TWC Digital Phone LLC as the universal service provider for the Powell Place subdivision shall not be used by the Commission or any other party as a basis for imposing on TWC Digital Phone LLC any other obligations applicable to local exchange carriers or competing local providers.

DOCKET NO. P-100, SUB 152b

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Notices Regarding Termination of	)	ORDER RULING ON USP STATUS FOR
Universal Service Provider Status	)	ROBINHOOD COURT APARTMENTS

BY THE COMMISSION: On July 21, 2009, Windstream North Carolina LLC (Windstream) filed a Notice of the transfer of universal service provider (USP) obligations as to the Robinhood Court Apartments (RCA) in the Old Town exchange in Forsyth County from itself to Time Warner Cable Information Services (NC), LLC (TWCIS).[1]

TWC Comments

On July 24, 2009, Time Warner Cable, Inc. and TWC Digital Phone, LLC (collectively, TWC) replied to Windstream's filing. TWC stated that (1) TWCIS is not a party to any contract with respect to RCA and has thus been inappropriately identified in Windstream's Notice; (2) that TWC is a party to an agreement to provide communications services to RCA, but this agreement does not "otherwise" preclude Winsdtream from providing services to this facility, nor is TWC aware whether access has been granted to the RCA properties coincident with a grant of access to TWC; and (3) regardless of the above, Windstream's designation of TWCIS (or, effectively, TWC) as the USP for RCA is erroneous, and TWC does not accept the USP designation for those apartments. TWC argued that the revision of G.S. 62-110(f4) by Session Law 2009-202 eliminated that aspect of the old law which resulted in the "automatic" shifting of the USP responsibility from a local exchange carrier (LEC) to a competitive carrier. Even if Windstream may be relieved of its USP responsibility with respect to RCA, that does not result in an automatic shifting of such responsibility to TWC.

Windstream Comments

On January 5, 2009, Windstream filed comments in response to TWC's filing. Windstream amended its Notice to identify TWC as the entity it now believes is providing service at the RCA. Windstream stated that the RCA was a newly-constructed multi-family project to which it had sent personnel to gather information regarding the installation of infrastructure. Windstream discovered that TWC had already installed facilities to serve various apartment buildings that comprise the RCA. In response to TWC's assertion that it lacked awareness as to whether access had been granted to Windstream at the RCA, Windstream hereby definitively stated that it had not been granted access to install infrastructure at the RCA. Thus, TWC has entered into an agreement providing it with access to the property to which Windstream is not a party. Under Subsection (i) of G.S. 62-110(f4), Windstream is entitled to be excused from any obligation to provide basic local exchange service or any other communications service to residents of the RCA.[2]

Windstream further stated that it has not seen the contract between TWC and the RCA and does not know whether the agreement was entered into after July 1, 2008, or whether it excludes the ILEC from providing communications services to that property. Even assuming

[1] See Attachment to Windstream's July 21, 2009 filing in which Windstream identifies "Time Warner Cable Information Services (NC), LLC" as the Universal Service Provider for the RCA.

[2] G.S. 62-110(f4) states in pertinent part that "[w]hen any telecommunications service provider: (i) enters into an agreement to provide local exchange service for a subdivision or other area where access to right-of-way for the provision of local exchange service by other telecommunications service providers has not been granted coincident with any other grant of access by the property owner; or (ii) enters into an agreement after July 1, 2008, to provide communications service that otherwise precludes the local exchange company from providing communications service for the subdivision or other area, the local exchange company is not obligated to provide basic local exchange telephone service or any other communications service to customers in the subdivision or other area."

that the agreement does not "otherwise preclude" Windstream from providing service at the RCA, this is not relevant inasmuch as Windstream has not been granted access to the property coincident with the grant of access to TWC by the property owner. Given Windstream's lack of infrastructure to provide service to the RCA and its resulting inability to serve as the USP at the RCA, Windstream is entitled under G.S. 62-100(f4) to be excused from any obligation to provide basic local exchange telephone service or any other communications service to residents of the RCA.

Windstream noted that TWC acknowledged in its July 24, 2009, filing that it takes no position on whether Windstream should be excused from any USP obligations at the RCA. Windstream stated that it likewise takes no position, at present, as to whether TWC should be designated as the USP for the RCA.

Public Staff Response

On January 29, 2010, the Public Staff filed comments stating that the instant situation appears to be similar to those in Docket No. P-1422, Sub 2, where TWC agreed to serve as the USP in the Villas Subdivision in Wake Forest under certain terms and conditions and Docket No. P-100, Sub 152b where TWC agreed to serve as the USP in the Powell Place subdivision in the Pittsboro exchange under certain conditions. Because of the similarity between the instant matter and those previous cases, the Public Staff stated that it believed that a comparable resolution would be in order regarding the USP at the RCA. The Public Staff reiterated its view that it is consistent with G.S. 62-110 and in the public interest that every region, area, subdivision, and customer should have a designated USP.

TWC Response

TWC argued that there is no need—or basis—for the Commission to take further action in this proceeding. G.S. 62-110(f4)(i) relieves the incumbent USP of USP responsibility with respect to a specific area or development where another telecommunications service provider "enters into an agreement to provide local exchange service for a subdivision or other area where access to right-of-way for the provision of local exchange service by other telecommunications service providers has not been granted coincident with any other grant of access by the property owner." This means that relief from the USP responsibility of the LEC is *granted by the operation of law upon notice to the Commission.* Under G.S. 62-110(f4), upon such notice, the other provider that is party to the agreement "shall be the provider in the subdivision or other area under the terms of the agreement and applicable law."

In the instant case, Windstream has submitted a notice of relief from USP responsibility for the RCA pursuant to G.S. 62-110(f4). No party has opposed Windstream's request for relief.[1] Moreover, no party or member of the public has raised any issue implicating USP obligations with respect to the RCA. Under these circumstances, G.S. 62-110(f4) contemplates

[1] TWC stated that it does not concede that the provision of Digital Phone services under its agreement to provide service to the RCA constitutes "local exchange service" within the meaning of G.S. 62-110(f4)(i). However, it will not be necessary for the Commission to reach this issue should it simply accept Windstream's notice without further action as contemplated by the plain meaning of G.S. 62-110(f4).

no further action by the Commission, and no formal "acceptance" of Winstream's notice is required or, arguably, permitted.

Thus, in the context of the present proceeding, there is no basis for the Commission to redesignate a new USP for the RCA. The General Assembly, under G.S. 62-110(f4), has expressly recognized that a LEC may be relieved of USP responsibilities *without the redesignation of a substitute provider.* Moreover, under the facts presented here (where an incumbent provider is simply giving notice that it has been relieved of USP responsibility due to lack of access to an area or development where access has been granted to another provider), the only mechanism authorized by G.S. 62-110(f4) for designation of a new USP is the procedure set forth in G.S. 62-110(f5). However, that provision only applies where the Commission finds, upon hearing, that the telecommunications service provider serving the subdivision or other area (i.e., TWC) is no longer willing or able to provide adequate services. But in the instant case TWC *is willing and able to serve* as the "provider" under the terms of its agreement with the RCA. Thus, there is no factual or legal basis upon which the Commission may make a redesignation on the record before it.

TWC further argued that the present situation is readily distinguishable from the Shentel (Docket No. P-1422, Sub 2 (October 31, 2008)) or Powell Place (Docket No. P-100, Sub 152b (January 5, 2010)) proceedings where the Commission designated TWC the USP subject to agreed-upon stipulations. In those proceedings, the Commission was presented with affirmative requests for relief from USP obligation by an *intermediate* provider, which was necessitated by G.S. 62-110(f4) as formerly written. As formerly written, USP responsibility was "automatically" shifted to the competitive provider and relief of that responsibility could only be obtained by application to the Commission. Pursuant to this requirement, as the intermediate providers with formal USP responsibilities, Shentel Converged Services and Madison River Communications petitioned the Commission for relief of these responsibilities. By contrast, in the present case there is no intermediate provider seeking to be relieved of a formal designation, but rather a LEC simply providing notice that it is no longer the USP. As revised, G.S. 62-110(f4) contemplates competitive services under the terms of an applicable contract in the absence of a formal USP designation. Hence, no action by the Commission is required or permitted under the facts presented here. This revision is actually more efficient in that it recognizes that the obligation to serve may be passed from one provider to another by contract without the necessity of formal application to the Commission.

While the Commission and Public Staff may believe that public policy favors the designation of a USP for every consumer in the State, G.S. 62-110(f4) establishes a different statutory scheme that reflects the current competitive environment. This new regulatory scheme holds that no formal USP designation is required where service is provided under contract to a defined service area such as an apartment building or development. The public interest in universal access to telephone service is ultimately protected by the authority retained by the Commission to designate a formal provider if the competitive provider is unwilling or unable to provide service. However, in the absence of such a showing, no designation is contemplated by statute.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

A central question posed by this docket is whether TWC can be considered, or should be designated, the USP for the RCA. For the reasons set forth in more detail below, the answer to that question is negative. Simply put, G.S. 62-110(f4) provides the criteria by which a *LEC* can be relieved of its USP responsibilities for a given area, but G.S. 62-110(f5) fails to provide a procedure by which a telecommunications service provider[1] (TSP) can replace a LEC as the USP.

No party, including TWC, maintains that Windstream is still the USP for the RCA. Conversely, Windstream takes no position on whether TWC should be the USP for the RCA. The Public Staff states that every customer should have a USP in place and argues the best candidate for that responsibility is TWC.

G.S. 62-110(f4) sets out three ways a LEC can be relieved of its USP obligation in a given area. The first is G.S. 62-110(f4)(i), when a TSP enters into an agreement to provide local exchange service for the affected area where access to right-of-way for the provision of local exchange service *by other TSPs* has not been granted coincident with any grant of access by the property owner. The second is G.S. 62-110(f4)(ii), when the TSP has entered into an agreement after July 1, 2008, to provide communications service that otherwise precludes the local exchange company from providing communications service for the subject area.[2] Finally, there is a third "catch-all" provision in the last paragraph of G.S. 62-110(f4) that allows the Commission to grant a LEC a waiver of its USP responsibilities for good cause shown—namely, that providing service to the area would be inequitable or unduly burdensome to the LEC, that one or more alternative providers of local exchange service exist, and that granting the waiver is in the public interest.

In the case of G.S. 62-110(f4)(i) and (ii), the statute states that the LEC "shall be relieved" of any USP obligations to serve customers in the subject area if the criteria are met. Windstream has given notice that it believes it has qualified for relief under G.S. 62-110(f4)(i). In its January 5, 2010 Comments, Windstream definitively stated that "it has not been granted [coincident] access to install infrastructure to serve the apartment building that comprise the [RCA]." Windstream continued: "[S]ince Windstream has clearly established the first criterion for its excusal—it was not granted access to the property 'coincident' with the grant of access to Time Warner by the property owner," the G.S. 62-110(f4)(ii) provision is not under consideration.

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[1] G.S. 62-110(f6) defines "telecommunications service provider" as "a competing local provider, or any other person providing local exchange service by means of voice-over-Internet protocol, wireless, power line, satellite or other nontraditional means, whether or not regulated by the Commission, but the term shall not include local exchange companies or telephone membership corporations."

[2] The statute also requires the LEC, in both instances, to "provide written notification to the appropriate State agency" (i.e., in this case the Commission) that the LEC is no longer the USP for the affected area. However, the statute as it pertains to the first two methods of relief does not make relief from the USP responsibility for a given area contingent on notice to the Commission but rather the relief occurs by operation of law once one or the other of the provisions has been satisfied.

But has Windstream "clearly established" its G.S. 62-110(f4)(i) grounds for excusal? Unfortunately, it has not. The text of G.S. 62-110(f4)(i) applies only in situations in which a TSP had entered "into an agreement to provide local exchange service for a subdivision or other area where access to right-of-way for the provision of local exchange service *by other telecommunications service providers* has not been granted coincident with any other grant of access by the property owner." (Emphasis added). Windstream has only established that it, a LEC, was not granted such coincident right-of-way access, not that other TSPs had not been granted such access.[1] Both LEC and TSP are separately defined terms for the purposes of (f4) and (f5) in G.S. 62-110(f6).

Nevertheless, based on the filings made by Windstream in this docket, the Commission considers the "catch-all" provision that appears at the end of G.S. 62-110(f4) to be applicable and will treat Windstream's filings as a Motion for relief under the last paragraph of G.S. 62-110(f4). Accordingly, the Commission finds that Windstream should be, and hereby is, granted a waiver of its carrier of last resort obligations at the RCA inasmuch as it has shown that (1) providing service in the RCA would be inequitable or unduly burdensome,[2] (2) one or more alternative providers of local exchange service exist (i.e., TWC), and (3) the granting of such a waiver is in the public interest.

The question then becomes: Who, if anyone, should be the official USP for the RCA? G.S. 62-110(f5) is the provision that allows the redesignation of USP responsibility by the Commission to the relevant *LEC* or to another TSP upon a showing "that the *telecommunications service provider* serving that subdivision or other area pursuant to subsection (f4) of this section...is no longer willing or no longer able to provide adequate services to the subdivision or other area." (Emphasis added). Put another way, G.S. 62-110(f5) does not by its terms provide for redesignation of USP responsibility when a *LEC* has been relieved of its USP responsibilities and a TSP is providing adequate service in the area and is willing and able to continue to provide that service. G.S. 62-110(f5) only comes into play when a *TSP* is unwilling or unable to provide adequate service.

As TWC points out, the instant scenario does not fit into G.S. 62-110(f5). TWC, as current provider, is in fact *willing and able* to provide adequate service to the RCA. There is thus no basis under G.S. 62-110(f5) for designating either Windstream or TWC as the USP provider in the RCA at this time.

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[1] The Commission recognizes that a LEC might have difficulty in establishing that TSPs other than the provider have not been granted coincident access. However, common sense suggests that, if the LEC has not been granted coincident access, it is highly unlikely that other TSPs would have been granted access as well. Accordingly, for future reference with regard to a LEC's notice of relief under G.S. 62-110(f4)(i), the Commission would accept the validity of a notice that states that neither the LEC nor another TSP, to the best of the LEC's knowledge and belief, has been granted coincident access to the subject area.

[2] In its January 5, 2010 Comments, Windstream noted that it currently lacks the infrastructure necessary to serve the RCA. Under the circumstances, the Commission finds that it would, therefore, be "inequitable or unduly burdensome" to require Windstream to continue to be the USP for the RCA, particularly since TWC stands ready, willing, and able to provide adequate communications service in the area.

The Commission concurs with TWC that, while it might be satisfying from a formal point of view that a USP must be designated to cover every consumer, it does not appear that the current law allows for it. The fact is that G.S. 62-110(f4) sets out ways by which a LEC can in certain circumstances be relieved of USP responsibilities, but it does not at the same time provide an infallible method under which others can be made to assume them. Nor does G.S. 62110(f5) provide for a redesignation of USP responsibility to the LEC or to another TSP in a given area *unless* the current TSP is no longer willing or able to provide adequate service.

Accordingly, the Commission concludes that, since Windstream has, by this Order, been granted a waiver and relief from its USP responsibilities for the RCA, neither Windstream nor TWC has the current USP designation for the RCA, provided, however, that if, at some point in the future, TWC is no longer willing or able to provide adequate service, Windstream may again be designated, or another TSP may be designated, as having the USP responsibility pursuant to G.S. 62-110(f5).

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the __12th__ day of April, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

DI041210.02

DOCKET NO. P-100, SUB 165

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Implementation of Subsection (h)	)	ORDER CONCERNING
Price Plans Pursuant to House Bill 1180,	)	WORKING GROUP
Session Law 2009-238	)	REPORT

BY THE COMMISSION: On June 30, 2009, House Bill 1180 became law as set forth in Session Law 2009-238 (hereinafter S.L. 238). Entitled "An Act Establishing The Consumer Choice And Investment Act of 2009", the law creates a new category of price plan which any local exchange carrier (LEC) or competing local provider (CLP) may opt into by simply "filing notice of its intent to do so with the Commission", the election being effective immediately upon filing. The Commission refers to these new price plans in general as "Subsection (h) price plans".

On July 21, 2009, the Commission issued an Order Requesting Comments and Instituting Certain Interim Requirements wherein the Commission began the process of determining an orderly procedure for carriers to follow when adopting a Subsection (h) price plan and addressing further implications of S.L. 238. In its July 21, 2009 Order, the Commission noted that Commission rules, statutes, notice, and reporting obligations may be impacted by S.L. 238. The Commission noted that, while rules and statutes are the most salient items affected by the passage of S.L. 238, there are also orders that the Commission has issued over the years that have imposed notice obligations and reporting requirements on LECs that may be affected by a Subsection (h) election. The Commission determined that it was appropriate to solicit comments from parties setting forth those statues, Commission rules, notice, and reporting obligations that they believe will no longer be in force for a LEC or CLP in such circumstances, together with the reasons therefore.

On October 20, 2009, the Commission issued its Order Implementing Certain Requirements in this proceeding. In its October 20, 2009 Order, the Commission concluded, after reviewing the initial and reply comments filed by the parties in response to the July 21, 2009 Order, that the Public Staff and the other commenting parties to this docket should be directed to address this issue, and, to that end, should be constituted as a Working Group[1] to develop a matrix that: (a) addresses which statutes, Commission rules, and notice and reporting obligations that will no longer be in force for a company electing a Subsection (h) price plan; (b) suggests any necessary changes to those rules or notice and reporting obligations; and (c) sets out any differing positions and the rationales therefore. The Commission further stated that the parties may also address in the matrix any issues that they have come to believe are relevant, necessary, and convenient for Commission decision. The parties were directed to file such a matrix by no later than 45 days from the issuance of the October 20, 2009 Order.

After being granted two extensions of time to file, on February 2, 2010, the Working Group filed its Report and Matrix. A copy of the Matrix is attached hereto as Appendix A. The Working Group stated that, as requested by the Commission, it prepared the Matrix attached to the February 2, 2010 Report which addresses how North Carolina statutes and Commission rules associated with the provisioning, rating, and regulation of telecommunications services should be impacted for Subsection (h) electing carriers. The Working Group described how the Matrix is divided into seven columns. It noted that column one assigns an issue number to each statue or rule examined by the Working Group – a total of 92 issues were addressed. It noted that column two provides a Commission rule or statutory reference for each issue. Further, the Working Group commented that column three provides a description of each issue, while column four provides a brief summary of the Working Group's conclusions reached for each issue. The Working Group stated that columns five through seven confirm each party's position on the Issue as well as additional comments individual to a party. The Working Group noted that the issues are arranged in a sequential manner with statutory issues addressed first and Commission rules afterwards.

[1] The members of the Working Group include: the Public Staff, The North Carolina Telecommunications Industry Association, Inc. (NCTIA), and the Competitive Carriers of the South, Inc. (CompSouth). CompSouth's members include: Access Point Inc.; Birch Communication (f/k/a ACCESS Integrated Networks, Inc.); Cavalier Telephone; Cbeyond Communications; Covad Communications Company; Deltacom, Inc.; Level 3 Communications; NuVox Communications, Inc.; tw telecom of north carolina l.p.; and XO Communications, Inc.

The Working Group noted that it had reached consensus on most of the 92 issues. The Working Group further noted that it had concluded that 14 issues were unaffected by S.L. 238[1], since they were either unrelated to retail deregulation or the Commission retained jurisdiction through S.L. 238.

The Working Group maintained that it had substantial discussion concerning the application of the statutes from which price plan companies are explicitly exempted under Subsection (g) of G.S. 62-133.5[2] to Subsection (h) electing companies. These statutes are identified in the Matrix as Issue Nos. 1, 2, 3, 6, 11, 13, 14, 15, 16, 19, 20, 21, 22, 24, 26, and 28. With respect to these Matrix Issues, the Working Group conceded that Subsection (h) electing companies are not automatically exempted from the statutes identified in Subsection (g) for price plan companies. The Working Group further noted that it does not have a consensus position, however, on whether the Commission has the authority to apply the Subsection (g) statutes to the retail services of Subsection (h) electing entities or, if it does, the extent to which Subsection (h) electing entities should be exempted from the operation of the Subsection (g) statutes.

The **NCTIA** believes Subsection (h) electing companies should receive the same exemptions as given to price plan regulation companies 15 years ago in Subsection (g). The NCTIA and the Public Staff agree that the election provided for in Subsection (h) as part of S.L. 238 is the next step in the evolutionary process toward deregulation that has been recognized by both the Commission and the General Assembly. The NCTIA asserts that applying the statutes enumerated in Subsection (g) to companies that qualify for a higher degree of deregulation than the price plan regulation process adopted in 1995 is illogical, as it would imply that companies whose retail services are effectively deregulated under a Subsection (h) election should be subjected to a higher degree of regulation than a price plan regulated company operating under a more rigid regulatory basis adopted in 1995. The NCTIA maintains that the only logical conclusion is that the Subsection (g) exemptions should be applicable to companies making an election under Subsection (h).

The **Public Staff** generally agrees with the NCTIA but believes there is merit to exempting companies electing under Subsection (h) from the provisions of G.S. 62-111(a) except as to compliance with the procedures for transfer of control similar to those applicable to CLPs under Commission Rule R17-8. Additionally, the Public Staff and CompSouth believe that G.S. 62-132 should still apply to stand-alone residential service. And, for many of the Subsection (g) statutes, their applicability to the non-retail services of Subsection (h) entities will be addressed in future comments.

Both the NCTIA and the Public Staff believe that the Commission could allow such exemptions as are found under G.S. 62-133.5(g) under the provisions of G.S. 62-2(b) where the Commission is "authorized after notice to affected parties and hearing to deregulate or to exempt

[1] These issues include Issue Nos.: 7, 8, 9, 10, 35, 40, 61, 62, 68, 69, 70, 75, 78, and 86.

[2] G.S. 62-133.5(g) reads, "[t]he following sections of Chapter 62 of the General Statutes shall not apply to local exchange companies subject to price regulation under the terms of subsection (a) of this section: G.S. 62-35(c), 62-45, 62-51, 62-81, 62-111, 62-130, 62-131, 62-132, 62-133, 62-134, 62-135, 62-136, 62-137, 62-139, 62-142, and 62-153."

from regulation under any or all provisions of this Chapter, including telecommunications companies defined under G.S. 62-3(23)a.6." The Working Group noted that the alternative is to request that the legislature make a technical correction in S.L. 238 to include these statutory exclusions.

CompSouth recognizes that S.L. 238 is intended as a deregulatory statute. However, CompSouth notes that the General Assembly has achieved this deregulation in a different manner than with price plan regulation or in authorizing local competition. Here, in contrast to the previous forays into deregulation, the General Assembly has pinpointed deregulation in a specific area – retail services – by directly restricting the Commission's authority over those services. However, this approach creates some ambiguity where a specific requirement may have retail and non-retail components or goals, but the approach does at least clearly establish the scope and extent of deregulation desired.

Given this, there is no reason for the Commission, at this stage, to go further and purport to grant a broader exemption under statutes that the General Assembly did not elect to amend. Clearly, in the context of price regulation plans, the General Assembly intended that the authority granted by the statutes specified in Subsection (g) would be replaced by the "negotiated" requirements of the applicable price regulation plan – e.g., the Commission would not establish depreciation rates since the pricing methodology would be established in the price regulation plan. Here, depending on how the Commission resolves the issue of whether price regulation plans can survive a Subsection (h) election, there may be no such structure to govern pricing and related requirements for services remaining within the Commission's jurisdiction. The General Assembly may be presumed to have recognized that carrying forward the Subsection (g) exemptions of electing entities – in the absence of price regulation plans -- would leave a regulatory vacuum with respect to matters within the Commission's jurisdiction.

In any event, the Commission retains authority over wholesale services and the parties have not yet fully examined the potential application of the Subsection (g) statutes to the Commission's retained authority. Moreover, several of the Subsection (g) statutes are general grants of authority to the Commission – not regulatory requirements imposed on regulated entities – and it is not necessary or, perhaps, appropriate for the Commission to exempt electing entities from such statutes in the context of this proceeding.

Finally, there is an open question as to whether the Commission has the authority to exempt electing entities from the operation of the Subsection (g) statutes given that the legislature did not itself grant such exemption. While the Commission did exempt CLPs from the operation of various statutes in implementing local competition, it did so in the context of an explicit directive from the General Assembly to establish the regulatory regime that would govern local competition. Here, no such directive has been given by the General Assembly; to the contrary, S.L. 238 quite clearly and specifically operates to constrain the Commission's authority with respect to deregulated entities. To be clear, CompSouth, at this point, is not requesting the Commission to exercise authority under Subsection (g) statutes to impose new requirements on electing entities – but rather CompSouth is pointing out that the Commission's authority under these statutes is undisturbed except as explicitly set forth in S.L. 238.

The Working Group further noted that the Commission's October 20, 2009 Order requested that parties in this docket further negotiate the treatment of non-retail services, an issue not addressed in the Commission's July 21, 2009, Order Requesting Comments and Instituting Certain Interim Requirements. The Working Group asserted that, specifically, the Commission requested that parties provide a joint recommendation as to how non-retail services should be regulated by the Commission once a company makes a Subsection (h) election. The Working Group stated that the Commission did not specify a time frame required for the parties to complete negotiations and make final recommendations regarding this issue; therefore, this issue is not addressed in the Working Group's February 2, 2010, Report. The Working Group noted that it had concluded that retail issues required more immediate attention in order for companies to proceed with their Subsection (h) elections. Thus, the focus of the February 2, 2010 filing is on rules, statutes, notice and reporting obligations that would no longer be in force. The Working Group stated that the regulation of non-retail services, excluding Intercarrier Compensation and Switched Access, will be addressed by the Working Group in the coming weeks.

The Report further noted that the NCTIA and CompSouth have sought reconsideration of certain aspects of the Commission's October 20, 2009 Order as it pertains to CLPs electing the new regulatory plan under Subsection (i). The Working Group stated that it does not take a position with regard to the issues under reconsideration, as the respective petitions speak for themselves. The Working Group maintained that, as to the Matrix attached to its February 2, 2010 filing, the Working Group notes that any statute, rule, order, or requirement that is relieved as to an ILEC should also be relieved as to an electing CLP, to the extent that such statute, rule, order, or requirement applies to a CLP in the first instance. The Working Group further noted that it had reviewed the requirements of Rule R17 and set forth its recommendations in the Matrix attached to its February 2, 2010 filing as to the requirements of Rule R17 that would no longer apply to electing CLPs.

The Working Group requested that the Commission review its findings and issue a final order to address the areas covered in the Matrix attached to its February 2, 2010 filing, understanding that the regulatory treatment of non-retail services will be addressed at a later date.

The Commission has reviewed the Working Group's Matrix and Report as filed on February 2, 2010 and has broken down the 92 issues into 10 groupings, as follows:

<u>Group No. 1</u>:

All of the parties agree to the resolution of the following issues:

<u>**Issue Nos. 5, 6, 7, 8, 9, 10, 12, 13, 14, 16, 18, 19, 20, 21, 22, 23, 24, 25, 27, 29, 30, 32, 33, 34, 35, 38, 39, 40, 41, 56, 58, 59, 60, 61, 62, 68, 69, 70, 72, 73, 74, 75, 76, 77, 78, 79, 80, 81, 82, 83, 84, 85, 86, 87, 88, 89, 91, and 92.**</u>

The Commission has reviewed these Issues and agrees that the Working Group's consensus position on each of these issues, except as noted below, is appropriate. Therefore, the

Commission adopts the Working Group's consensus position on each issue identified in Group No. 1 above, except as noted below.

For Issue No. 56, item (iv), the Working Group's consensus position is that the Commission should amend the CLP certificate application form so that, if desired, a CLP can file an application for certification and Subsection (h) election as the same time. The Commission is requesting that the Public Staff draft and file a copy of the said amended CLP certification application form within 30 days of the date of issuance of this Order for consideration by the Commission.

The Commission notes that in Issue No. 60, item (ii), the Working Group's position is that a simpler access line report format and longer filing frequency is acceptable and that the parties anticipate filing a separate proposal to modify this requirement.

For Issue No. 76, the Working Group's position is that Rule R-20-1(a), (b), (c), and (e) should be revised to reflect the Federal Communication Commission's slamming requirements. The Commission is hereby requesting the Public Staff to draft and file a copy of a new proposed Rule R-20-1(a), (b), (c), and (e) within 30 days of the date of issuance of this Order for consideration by the Commission.

For Issue No. 88, item (i), the Working Group's position is that the Central Office Equipment Report, required by a standing data request, origin uncertain, should be eliminated for all Subsection (h) entities and all other LECs. The Commission finds eliminating the requirement for all other LECs to be outside the scope of this proceeding. The Commission will address this change in the context of another docket. In this proceeding, the Commission is finding it appropriate to eliminate the Central Office Equipment Report for all Subsection (h) entities.

And, finally, the Commission notes that in Issue No. 92, item (i), the Working Group's position is that the parties anticipate filing a separate proposal to modify the requirements of the Station Development Report which outlines access line information.

Group No. 2:

Issue Nos. 36 and 37 – The NCTIA and the Public Staff agree with the Working Group's positions, and CompSouth does not take a position on the need for the specific requirement at this time. Specifically, Issue Nos. 36 and 37 are detailed in the Matrix, as follows:

Issue No. 36

Rule R9-2 – Uniform System of Accounts (USOA)

Working Group Position for Subsection (h) entities:

- Subsection (h) entities should be exempted.

The NCTIA and the Public Staff agree with the Working Group's position.

CompSouth does not take a position on continued need for this requirement at this time.

Issue No. 37

Rule R9-3 – Annual Filing of Construction Plans and Objectives

Working Group Position for Subsection (h) entities:

(i) Subsection (h) entities should be exempted.

(ii) Rule should be eliminated for Subsection (h) and all other LECs.

The NCTIA and the Public Staff agree with the Working Group's position.

CompSouth does not take a position on continued need for this requirement at this time.

The Commission has reviewed these Issues and generally agrees with the Working Group's position on Issue Nos. 36 and 37 while noting that CompSouth has not taken a position on these issues at this time.

However, the Commission does not agree that this proceeding is the appropriate proceeding to eliminate the applicability of Rule R9-3 for rate-of-return ILECs[1], as contemplated by the Working Group's position on Issue No. 37 which states that the rule should be eliminated for Subsection (h) and all other LECs. The purpose of this proceeding is to determine which rules, statutes, and so forth should not be enforceable for Subsection (h) entities. It is not the appropriate proceeding to determine whether a Commission rule should still be applicable to rate-of-return ILECs. However, the Commission will address this change in the context of another docket.

Therefore, the Commission finds it appropriate to conclude in the context of this proceeding that Subsection (h) entities should be exempted from Rule R9-2 and Rule R9-3.

[1] By Order dated May 14, 2007, the Commission exempted price regulation plan ILECs from Rule R9-3.

Group No. 3:

Issue Nos. 42[1], 43, 44, 45, 46, 47, 48, 49, 50, 51, 52, 53, 54, 55, 57, 63, 64, 65, 66, 67, and 71 – These are Issues wherein the NCTIA and the Public Staff agree with the Working Group's position that these rules are not applicable to Subsection (h) entities and CompSouth also agrees. However, CompSouth also asserted that these same rules should be relieved for all CLPs, not just CLPs that make a Subsection (h) election[2]: CompSouth further argues that it makes no sense that LECs are excused on grounds of competition but their competitors are not.

The Commission has reviewed these Issues and agrees with the positions taken by the NCTIA and the Public Staff. The Commission does not find merit in CompSouth's argument that the rules outlined in these Issues should be relieved for all CLPs, not only CLPs that make a Subsection (h) election. The Commission is not persuaded by CompSouth's argument since some its competitors, namely price plan regulated ILECs, will remain subject to the rules. The Commission concludes that only Subsection (h) entities, ILECs or CLPs, should be excused from the rules outlined in Group No. 3 herein.

Further, the Commission agrees with CompSouth's assertion that wholesale performance measures are unaffected by S.L. 238. Therefore, the Commission clarifies that an ILEC's wholesale performance measurement plan will not be affected by the company's adoption of a Subsection (h) plan.

[1] In Footnote No. 4 to the Matrix, it is noted that CompSouth believes that service quality standards for wholesale service would be unaffected by S.L. 238. The footnote also stated that, in the event a service quality standard for a LEC's wholesale service is measured by reference to a retail analog (whether by rule, order, or interconnection agreement), this retail analog would remain in place for Subsection (h) electing entities. Further, it was noted that in a similar proceeding, the Florida Commission has adopted the following clarifying language on this point: "None of the rule amendments or repeals are intended to impact in any way wholesale service or the SEEM (Self-Effectuating Enforcement Mechanism) plan, the SEEM metrics or payments, or the type of data that must be collected and analyzed for purposes of the SEEM plan." See Notice of Rule Making, Order No. PSC-09-0054-NOR-TP, Docket Nos. 080159-TP, 080641-TP (Florida Pub. Serv. Comm'n Jan. 23, 2009), at page 1. CompSouth asserted that similar clarification should be made in this proceeding.

[2] CompSouth noted that, for purposes of the Matrix, the Working Group uses the phrase "Subsection (h) entities" to include CLPs that opt into the Subsection (h) regulatory plan as permitted under Subsection (i). CompSouth's position is that electing CLPs do not become "Subsection (h)" entities by exercising the rights granted under Subsection (i) but rather they remain CLPs that receive the benefits of deregulation afforded Subsection (h) electing entities.

Group No. 4:

Issue Nos. 1, 2, 3, 26, and 28 - Issues wherein the NCTIA and the Public Staff agree with the Working Group's position and CompSouth agrees with (i)[1] and (ii)[2] of the Working Group's position, but does not presently foresee a need for the Commission to exercise its authority as contemplated in (iii)[3].

CompSouth asserted that S.L. 238 is intended as a deregulatory statute. CompSouth also recognized that ILECs operating under price regulation plans benefit from certain statutory exemptions specified in G.S. 62-133.5(g) which are not carried forward for Subsection (h) electing entities. CompSouth maintained that, with that said, it is not necessary for the Commission to broadly exempt electing entities from Subsection (g) statutes at this time. CompSouth argued that, first, the Commission retains authority over wholesale services and the parties have not yet fully examined the potential application of the Subsection (g) statutes to the Commission's retained authority. CompSouth stated that, second, several of the Subsection (g) statutes are general grants of authority to the Commission – not regulatory requirements imposed on regulated entities – and it is not necessary or, perhaps, appropriate for the Commission to exempt electing entities from such statutes in the context of this proceeding. CompSouth maintained that, third, there is an open question whether the Commission has the authority to exempt electing entities from the operation of these statutes given that the legislature did not itself grant such exemption.

The Commission has reviewed these Issues and agrees with CompSouth that it is not necessary for the Commission to broadly exempt electing entities from Subsection (g) statutes at this time for the reasons given by CompSouth. The Commission notes that item (i) of the Issues outlined in Group 4 provides that the statues in question are not applicable to the retail services offered by Subsection (h) entities. The Commission agrees with CompSouth that, at this time, this finding goes far enough to make sure that statutes are not applied to the retail services of Subsection (h) entities as is required by S.L. 238.

Further, the Commission notes that it specifically agrees with the consensus Working Group position that the G.S. 62-133.5(g) exemptions apply only to ILECs adopting traditional price plan regulation; it does not automatically apply to Subsection (h) entities (See Issue No. 18 of the Matrix). Any determination of statutes no longer applicable to Subsection (h) entities is to be handled within the context of this proceeding, not simply by applying G.S. 62-133.5(g) to Subsection (h) entities.

[1] (i) states that the particular statute is not applicable to the retail services offered by Subsection (h) entities.

[2] (ii) states that exemptions granted under Subsection (g) do not automatically apply to Subsection (h) entities.

[3] (iii) states that Subsection (h) entities should be exempted from the referenced statute.

Group No. 5:

Issue No. 4 – G.S. 62-73. Complaints. The NCTIA and the Public Staff agree with the Working Group's position that G.S. 62-73 concerning complaints is not applicable to retail services offered by Subsection (h) entities. CompSouth, however, disagrees and argues that the Commission and other affected parties still have the right, granted by statute, to file complaints with the Commission concerning retail services. CompSouth maintained that the Commission's authority to resolve such complaints is limited by S.L. 238. CompSouth asserted that, in addition, CLPs and LECs have independent authority under G.S. 62-133.5(e) to file complaints alleging anticompetitive activity under G.S. 62-73.

The Commission has reviewed this Issue and notes that, with the enactment of S.L. 238, there are now *two* statutes addressing complaints, namely, G.S. 62-73 and G.S. 62-73.1. Interestingly, the text of G.S. 62-73.1 is not by its terms restricted to complaints against Subsection (h) entities. The first question is how to harmonize these two provisions, since the Commission must strive to construe these provisions together, in order to give effect to both. Given the context that G.S. 62-73.1 was enacted within S.L. 238, which authorized Subsection (h) price plans for LECs and CLPs, the Commission can only reasonably conclude that the General Assembly intended that G.S. 62-73.1 would be the sole avenue for complaints about *retail* services against Subsection (h) entities. This conclusion is fortified by the use of the word "consumer" in G.S. 62-73.1. This word is generally used to denote an end-user of services, not one who buys services to sell to others. This conclusion is also fortified by the fact that Subsection (h) speaks to the deregulation of *retail* services. It also follows that complaints, retail or wholesale, against *non*-Subsection (h) entities would continue to be justiciable under G.S. 62-73.

The question posed by CompSouth is whether a CLP may file a complaint against a Subsection (h) entity under G.S. 62-73 with respect to retail services a CLP itself consumes from a Subsection (h) entity. Applying the above principles, the answer to this question is "No" as to retail services that the CLP consumes for itself. The only avenue available for complaints about the Subsection (h) retail services such a CLP receives is by way of G.S. 62-73.1. However, complaints from a CLP against a Subsection (h) entity with respect to wholesale services may still be heard under G.S. 62-73.

Group No. 6:

Issue No. 11 – G.S. 62-111 – Transfers of Franchises; Mergers, Consolidations, and Combinations of Public Utilities – CompSouth agrees with the Working Group's positions ((i) that G.S. 62-111 is not applicable to retail services offered by Subsection (h) entities; (ii) that exemptions granted under Subsection (g) do not automatically apply to Subsection (h) entities; and (iii) that G.S. 62-111 is applicable to non-retail services provided by Subsection (h) entities). The NCTIA agrees with (i) and (ii), but disagrees with (iii) that this statute is applicable to non-retail services provided by Subsection (h) entities. The NCTIA argues that G.S. 62-111 does not need to apply to Subsection (h) companies for non-retail service since the statute is excluded for price regulation companies. The Public Staff's position is that Subsection (h) entities should be required to adhere to the requirements adopted by the Commission in Rule R17-8 which is currently only applicable to CLPs.

The Commission has reviewed this Issue and agrees with the Public Staff's position that Subsection (h) entities should be required to adhere to the requirements adopted by the Commission in Rule R17-8 which is currently only applicable to CLPs. The Commission believes that G.S. 62-111 should not be applicable to the retail services offered by Subsection (h) companies and notes that under G.S. 62-133.5(g), price plan regulation companies are not required to adhere to G.S. 62-111. The Commission agrees with the Public Staff that the best fit for this situation is to require Subsection (h) entities to adhere to Rule R17-8 regardless of the types of services offered.

<u>Group No. 7</u>:

<u>Issue No. 15</u> – G.S. 62-132 – Rates Established Under this Chapter Deemed Just and Reasonable; Remedy for Collection of Unjust or Unreasonable Rates – CompSouth and the Public Staff agree with the Working Group's positions ((i) that G.S. 62-132 is not applicable to retail services offered by Subsection (h) entities except for its application to stand-alone residential service; (ii) that exemptions granted under Subsection (g) do not automatically apply to Subsection (h) entities; and (iii) that applicability to non-retail services provided by Subsection (h) entities will be addressed in future comments on non-retail regulation of Subsection (h) entities).

G.S. 62-132 reads as follows:

> The rates established under this Chapter by the Commission shall be deemed just and reasonable, and any rate charged by any public utility different from those so established shall be deemed unjust and unreasonable. Provided, however, that upon petition filed by any interested person, and a hearing thereon, if the Commission shall find the rates or charges collected to be other than the rates established by the Commission, and to be unjust, unreasonable, discriminatory or preferential, the Commission may enter an order awarding such petitioner and all other persons in the same class a sum equal to the difference between such unjust, unreasonable, discriminatory or preferential rates or charges and the rates or charges found by the Commission to be just and reasonable, nondiscriminatory and nonpreferential, to the extent that such rates or charges were collected within two years prior to the filing of such petition.

The NCTIA disagrees with (i) and agrees with (ii) and (iii) above. The NCTIA argues that G.S. 62-132 addresses unjust and unreasonable rates and therefore, expands the authority of the Commission beyond the intent of S.L. 238. The NCTIA maintains that G.S. 62-133.5(h)(2) provides full authority to the Commission to ensure compliance of this requirement.

The Commission has reviewed this Issue and agrees with the NCTIA's position. The Commission notes that G.S. 62-132 is not applicable to price regulation plan companies as provided for in G.S. 62-133.5(g). The Commission believes that G.S. 62-133.5(h)(2), implemented under S.L. 238, provides for all of the Commission's authority over stand-alone basic residential service and that it is not appropriate to find that G.S. 62-132 applies to stand-alone basic residential service as proposed by both CompSouth and the Public Staff. Therefore, the Commission agrees with the Working Group's position for Issue No. 15, except item (i) should be modified to read, "(i) not applicable to retail services offered by Subsection (h) entities."

<u>Group No. 8</u>:

<u>Issue No. 17</u> – G.S. 62-133.5(f) – Retail Promotions – The NCTIA and the Public Staff agree with the Working Group's position that G.S. 62-133.5(f) concerning retail promotions is not applicable to retail services offered by Subsection (h) entities. CompSouth agrees but states that the Commission retains jurisdiction over carrier compensation issues and may wish to consider whether it is necessary to impose a notice requirement to ensure that CLPs have notice of availability of retail service and promotional offerings.

The Commission has reviewed this Issue and agrees that G.S. 62-133.5(f) should not apply to retail services offered by Subsection (h) entities. The Commission finds that CompSouth's suggestion that the Commission consider whether it is necessary to impose a notice requirement to ensure that CLPs have notice of availability of retail service and promotional offerings is outside the scope of this proceeding. The purpose of this proceeding is to determine which rules, statutes, and so forth are no longer applicable to Subsection (h) entities, and CompSouth's suggestion concerning notice requirements for retail promotions is simply outside the scope of this proceeding for Commission consideration. CompSouth may, of course, at its discretion file a specific and detailed proposal with the Commission seeking changes to the notice requirements for retail promotions.

<u>Group No. 9</u>:

<u>Issue No. 31</u> – Rule R1-15 – Investigation and Suspension Proceedings – The NCTIA and the Public Staff agree with the Working Group's position that Rule R1-15 is not applicable to retail services of Subsection (h) entities and that applicability of Rule R1-15 to non-retail services provided by Subsection (h) entities will be addressed in future comments on non-retail regulation of Subsection (h) entities. CompSouth agrees except argues that R1-15 should be construed to apply to stand-alone basic residential service of electing entities.

Rule R1-15 states, in part:

> Whenever there shall be filed with the Commission by any public utility or carrier, subject to its jurisdiction, any schedule stating new or changed rate or rates, as provided by General Statutes of North Carolina, §§ 62-134, 62-135, 62-138, 62-140, 62-142, or 62-146, the Commission may, upon protest or complaint of the Public Staff or of any interested party, or upon its own initiative, suspend such rates or charges pending an investigation of the lawfulness thereof, and to that end the following proceedings will be in order. . . .

The Commission has reviewed this Issue and agrees with the Public Staff and the NCTIA that: (i) Rule R1-15 is not applicable to retail services of Subsection (h) entities; and (ii) the applicability of Rule R1-15 to non-retail services provided by Subsection (h) entities will be addressed in future comments on non-retail regulation of Subsection (h) entities. The Commission does not agree with CompSouth's suggestion that Rule R1-15 should be construed to apply to stand-alone basic residential service of electing entities. S.L. 238, and specifically G.S. 62-133.5(h)(2), provides all of the new pricing rules that will apply to stand-alone residential service and Rule R1-15 will no longer apply to any retail service offering of Subsection (h) entities.

Group No. 10:

Issue No. 90 – Price Regulation Plan Dockets – The NCTIA and the Public Staff agree with the Working Group's position that price regulation plans are no longer in effect for Subsection (h) entities. CompSouth agrees that price regulation reports and other retail regulations contained in price plans are superseded by a Subsection (h) election. CompSouth asserted that it is an open question whether other, non-retail requirements set forth in price plans continue to survive. CompSouth maintained that price plans could potentially provide a vehicle for regulation of wholesale activities.

The Commission has reviewed this Issue and agrees with CompSouth that it is an open question whether non-retail requirements set forth in price regulation plans continue to survive. The Commission does conclude that upon a Subsection (h) election, the retail provisions contained in an ILEC's price regulation plan are no longer in effect. However, there are non-retail services also outlined in price regulation plans. The Commission considers the status of non-retail services contained in price regulation plans to be an open question that will be addressed in the future once the Working Group makes its filing concerning the appropriate prospective regulatory treatment of non-retail services for Subsection (h) entities.

IT IS, THEREFORE, ORDERED as follows:

1. That the Commission generally adopts the Working Group's consensus position on the following Issues (Group No. 1): Issue Nos. 5, 6, 7, 8, 9, 10, 12, 13, 14, 16, 18, 19, 20, 21, 22, 23, 24, 25, 27, 29, 30, 32, 33, 34, 35, 38, 39, 40, 41, 56, 58, 59, 60, 61, 62, 68, 69, 70, 72, 73, 74, 75, 76, 77, 78, 79, 80, 81, 82, 83, 84, 85, 86, 87, 88, 89, 91, and 92;

2. That the Public Staff shall draft and file a copy of an amended CLP certification application form within 30 days of the date of issuance of this Order for consideration by the Commission (Group No. 1; Issue No. 56);

3. That the Public Staff shall draft and file a copy of a new proposed Rule R-20-1(a), (b), (c), and (e) within 30 days of the date of issuance of this Order for consideration by the Commission (Group No. 1; Issue No. 76);

4. That, for Issue No. 88, item (i), the Working Group's position is that the Central Office Equipment Report, required by a standing data request, origin uncertain, should be eliminated for all Subsection (h) entities and all other LECs. The Commission finds eliminating

the requirement for all other LECs to be outside the scope of this proceeding. Such a change should be requested in the context of another docket. In this proceeding, the Commission is finding it appropriate to eliminate the Central Office Equipment Report for all Subsection (h) entities;

5. That, in the context of this proceeding, Subsection (h) entities should be exempted from Commission Rule R9-2 and Commission Rule R9-3 (Group No. 2; Issue Nos. 36 and 37);

6. That the Commission adopts the NCTIA's and the Public Staff's position on the following Issues (Group No. 3): Issue Nos. 42, 43, 44, 45, 46, 47, 48, 49, 50, 51, 52, 53, 54, 55, 57, 63, 64, 65, 66, 67, and 71. These same rules should not be relieved for all CLPs, but only CLPs that make a Subsection (h) election;

7. That an ILEC's wholesale performance measurement plan will not be affected by the company's adoption of a Subsection (h) plan;

8. That the Commission adopts the NCTIA's and the Public Staff's position on Issue Nos. 1, 2, 3, 26, and 28 (Group No. 4). CLPs that do not elect to operate under S.L. 238 are not to be relieved of the referenced statutes, only CLPs that provide notice that they will be operating under S.L. 238. Further, the Commission concludes that G.S. 62-133.5(g) applies only to ILECs adopting traditional price plan regulation; it does not automatically apply to Subsection (h) entities. Any determination of statutes no longer applicable to Subsection (h) entities is to be handled within the context of this proceeding, not simply by applying G.S. 62-133.5(g) to Subsection (h) entities;

9. That the only avenue available for complaints about the Subsection (h) retail services a CLP may receive is by way of G.S. 62-73.1; however, complaints from a CLP against a Subsection (h) entity with respect to wholesale services may still be heard under G.S. 62-73;

10. That Subsection (h) entities should adhere to Rule R17-8 (Group No. 6; Issue No. 11);

11. That the Commission agrees with the Working Group's position for Group No. 7; Issue No. 15, except item (i) should be modified to read, "(i) not applicable to retail services offered by Subsection (h) entities.";

12. That the Commission adopts the Working Group's consensus position that G.S. 62-133.5(f) concerning retail promotions is not applicable to retail services offered by Subsection (h) entities (Group No. 8; Issue No. 17). The Commission finds that CompSouth's suggestion that the Commission consider whether it is necessary to impose a notice requirement to ensure that CLPs have notice of availability of retail service and promotional offerings is outside the scope of this proceeding;

13. That the Commission adopts the NCTIA's and the Public Staff's position that Rule R1-15 is not applicable to retail services of Subsection (h) entities and that applicability to non-retail services provided by Subsection (h) entities will be addressed in future comments on non-retail regulation of Subsection (h) entities (Group No. 9; Issue No. 31). The Commission

does not agree with CompSouth's suggestion that Rule R1-15 should be construed to apply to stand-alone basic residential service of electing entities. S.L. 238 provides all of the new pricing rules that will apply to stand-alone residential service, and Rule R1-15 will no longer apply to any retail service offering of Subsection (h) entities;

14. That the Commission adopts CompSouth's position that it is an open question whether non-retail requirements set forth in price regulation plans continue to survive once a company elects a Subsection (h) plan (Group No. 10; Issue No. 90). The Commission does conclude that upon a Subsection (h) election, the retail provisions contained in an ILEC's price regulation plan are not longer in effect, however, there are non-retail services outlined in price regulation plans. The Commission considers the status of non-retail services contained in price regulation plans to be an open question that will be addressed in the future; and

15. That the issue of the appropriate regulatory treatment of non-retail services of Subsection (h) entities, and, subsequently which rules and statutes may still apply to non-retail services[1], will be addressed at a later date.

ISSUED BY ORDER OF THE COMMISSION.
This the 30th day of March, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Patricia Swenson, Deputy Clerk

bp032910.01

[1] Some Matrix Issues have a Working Group consensus position that the rule or statue does apply to non-retail services, and, as appropriate, the Commission has adopted those positions in the context of this Order.

DOCKET NO. P-100, SUB 165

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Implementation of Subsection (h) Price Plans Pursuant to House Bill 1180, Session Law 2009-238 and House Bill 466, Session Law 2010-173	)	ORDER ALTERING SUBSECTION (h) REQUIREMENTS FOR CLPs, ADOPTING AN AMENDED CLP CERTIFICATION APPLICATION FORM, AND AMENDING COMMISSION RULES R20-1(a), (b), (c), and (e)

BY THE COMMISSION: On April 8, 2010, the Commission issued its Order Ruling on Motions for Reconsideration in this docket. The April 8, 2010 Order outlined revised Subsection (h) filing requirements for local exchange companies (LECs) and competing local providers (CLPs) as reflected in Appendix A to the Order.

On August 2, 2010, House Bill 466, Session Law 2010-173 was signed into law by Governor Perdue. A copy of Session Law 2010-173 is attached to this Order as Appendix A. Session Law 2010-173 altered Subsection (h) as previously outlined in House Bill 1180, Session Law 2009-238.

By this Order, the Commission is altering the Subsection (h) requirements previously adopted by the Commission in its April 8, 2010 Order to appropriately reflect revisions necessary due to the passage of Session Law 2010-173. A copy of the amended Subsection (h) requirements reflecting Session Law 2010-173 is attached to this Order as Appendix B.

Further in this docket, on March 30, 2010, the Commission issued its Order Concerning Working Group Report. Ordering Paragraph No. 2 of the Order stated that the Public Staff should draft and file a copy of an amended CLP certification application form within 30 days of the date of issuance of the Order for consideration by the Commission. Further, Ordering Paragraph No. 3 stated that the Public Staff should draft and file a copy of a new proposed Rule R20-1(a), (b), (c), and (e) within 30 days of the date of issuance of the Order for consideration by the Commission.

On April 29, 2010, the Public Staff filed clean and redlined versions of: (1) a proposed amended CLP certification application form; and (2) a proposed amended version of Rules R20-1(a), (b), (c), and (e) as requested by the Commission.

The Public Staff noted in its filing that the proposed amended CLP certification application form addresses how a company may file an application for local exchange service certification and a Subsection (h) election at the same time. The Public Staff further noted that, pursuant to the Commission's March 11, 2010 Order in Docket No. M-100, Sub 134, applicants for CLP certification are also directed to provide electronic addresses.

The Public Staff also maintained that the proposed revisions to Rules R20-1(a), (b), (c), and (e) should ensure compliance with the Federal Communications Commission's (FCC's) current rules regarding slamming and any subsequent amendments to such rules.

On May 6, 2010, the Commission issued an Order allowing interested parties an opportunity to comment on the Public Staff's April 29, 2010 filing. No party filed comments on the Public Staff's April 29, 2010 filing.

WHEREUPON, the Commission finds it appropriate to adopt the revised Subsection (h) requirements necessary due to the passage of Session Law 2010-173 as reflected in Appendix B.

Further, the Commission finds it appropriate to adopt the amended CLP certification application form filed by the Public Staff on April 29, 2010, modified to recognize the passage of Session Law 2010-173, which will allow a company to file an application for local exchange service certification and a Subsection (h) election at the same time. A copy of the adopted amended CLP certification application form is attached to this Order as Appendix C, and the new application form is effective as of the date of this Order.

In addition, the Commission finds it appropriate to rescind Commission Rule R20-1(c) and to amend Commission Rules R20-1(a), (b), and (e) as reflected in the Public Staff's April 29, 2010 filing in order to ensure that the North Carolina Rules reflect the FCC's current slamming rules and any subsequent amendments to such rules. A copy of the amended Rules R20-1(a), (b), (c), and (e) is attached to this Order as Appendix D, and the amended Rules are effective as of the date of this Order.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 5th day of August, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

bp080410.01

APPENDIX A

GENERAL ASSEMBLY OF NORTH CAROLINA
SESSION 2009

SESSION LAW 2010-173
HOUSE BILL 466

AN ACT TO AMEND THE CONSUMER CHOICE AND INVESTMENT ACT OF 2009.

The General Assembly of North Carolina enacts:

SECTION 1. G.S. 62-133.5(g) reads as rewritten:

"(g) The following sections of Chapter 62 of the General Statutes shall not apply to local exchange companies subject to price regulation under the terms of subsection (a) of this ~~section:~~ section or electing companies subject to alternative regulation under the terms of subsection (h) of this section: G.S. 62-35(c), 62-45, 62-51, 62-81, 62-111, 62-130, 62-131, 62-132, 62-133, 62-134, 62-135, 62-136, 62-137, 62-139, 62-142, and 62-153."

SECTION 2. G.S. 62-133.5(h) reads as rewritten:

"(h) Notwithstanding any other provision of this Chapter, a local exchange company that is subject to rate of return regulation or subject to another form of regulation authorized under this section and whose territory is open to competition from competing local providers may elect to have its rates, terms, and conditions for its services determined pursuant to the plan described in this subsection by filing notice of its intent to do so with the Commission. The election is effective immediately upon filing. A local exchange company shall not be permitted to make the election under this section unless it commits to provide stand-alone basic residential lines to rural customers at rates that are less than or comparable to those rates charged to urban customers for the same service.

(1) Definitions. – The following definitions apply in this subsection:

a. Local exchange company. – The same meaning as provided in G.S. 62-3(16a).

b. Open to competition from competing local providers. – Both of the following apply:

1. G.S. 62-110(f1) applies to the franchised area and to local exchange and exchange access services offered by the local exchange company.

2. The local exchange company is open to interconnection with competing local providers that possess a certificate of public convenience and necessity issued by the Commission. The Commission is authorized to resolve any disputes concerning whether a local exchange company is open to interconnection under this section.

c. Single-line basic residential service. – Single-line residential flat rate basic voice grade local service with touch tone within a traditional local calling area that provides access to available emergency services and directory assistance, the capability to access interconnecting carriers, relay services, access to operator services, and one annual local directory listing (white pages or the equivalent).

d. Stand-alone basic residential line. – Single-line basic residential service that is billed on a billing account that does not also contain another service, feature, or product that is sold by the local exchange company or an affiliate of the local exchange company and is billed on a recurring basis on the local exchange company's bill.

(2) Beginning on the date that the local exchange company's election under this subsection becomes effective, the local exchange company shall continue to offer stand-alone basic residential lines to all customers who choose to subscribe to that service, and the local exchange company may increase rates

NC-RETS

North Carolina Renewable Energy Tracking System

Interim Operating Procedures

June 30, 2010

Disclaimer: This document is intended to guide the operations of NC-RETS, both the users of the system and its administrator, APX. It is intended to be consistent with the NC Utilities Commission's rules implementing North Carolina's Renewable Energy and Energy Efficiency Portfolio Standard. Please contact Commission Staff if you believe there is a conflict between these Operating Procedures and the Commission's rules. NC-RETS users can propose changes to these procedures by participating in the NC-RETS Stakeholders Group.

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Glossary

Account: An Account is the vehicle by which an individual or an organization participates in NC-RETS and uses the system to upload Renewable Energy Facility production data, or to create, hold, track and/or retire RECs in Sub-accounts, or to audit an Electric Power Supplier's compliance with North Carolina's Portfolio Standard. There are four Account types in NC-RETS: NC Electric Power Supplier, General, Qualified Reporting Entity, and Program Auditor.

Account ID: A unique NC-RETS identifier for an Account that is assigned by NC-RETS when the NC-RETS Administrator approves the Account in NC-RETS.

Account Holder: An Account Holder is a person or organization that has registered with NC-RETS and has established an Account in order to own RECs in NC-RETS, provide Renewable Energy Facility production data to NC-RETS, or audit a compliance program within NC-RETS.

Account Manager: An Account Manager is the administrator for an Account Holder's NC-RETS Account, having the ability to, among other things, setup and manage additional logins and login privileges for other Users, typically other employees of the same organization.

Active Certificates: An Active Certificate is a Renewable Energy Certificate or Energy Efficiency Certificate that is held in an Active Sub-account and that has not yet been retired. Such Certificates may be traded, transferred, exported or retired at the discretion of the Account Holder of the Active Sub-account, except that Energy Efficiency Certificates can be used for compliance with North Carolina's Portfolio Standard only by the Electric Power Supplier that produced them or by a group of affiliated Electric Power Suppliers using the same Utility Compliance Aggregator.

Active Sub-account: An Active Sub-account is a Sub-account of an Account Holder's Account and is the holding place for all Active Certificates. If the Account Holder is the owner of a Renewable Energy Facility, or is the Responsible Party of a Renewable Energy Facility, their Active Sub-account will be the first point of deposit for any Certificates created that are associated with the Project ID number, unless the Certificate is subject to a Forward Certificate Transfer. Similarly, if the Account Holder is an Electric

Power Supplier that operates an energy efficiency program, the related Certificates are created in an Active Sub-account. An Active Sub-account may be associated with one or more Projects.

Balancing Authority: The entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority area, and supports interconnection frequency in real time. Duke Energy and Progress Energy are the Balancing Authorities for most of North Carolina. PJM is the Balancing Authority for Dominion North Carolina Power's service area.

Bulletin Board Sub-account: The Bulletin Board Sub-account is an Active Sub-account of an Account Holder's Account and is the holding place for Active Certificates that the Account Holder has posted for sale on the Bulletin Board.

Certificate: NC-RETS issues two kinds of Certificates: Renewable Energy Certificates (RECs), and Energy Efficiency Certificates (EECs). Unless otherwise specified by statute, rule or NCUC order, NC-RETS will issue one Certificate for each MWh of energy produced by a Renewable Energy Facility or saved via an Electric Power Supplier-sponsored energy efficiency or demand-side management program. Certificates from Renewable Energy Facilities that are Multi-fuel Facilities shall be issued pursuant to Section 4.2.

Commission: The Commission is the North Carolina Utilities Commission.

Compliance Sub-account: A Sub-account used by an Electric Power Supplier or Utility Compliance Aggregator to demonstrate compliance with a specific year of Portfolio Standard obligation(s). The Account Holder places Certificates into the Compliance Sub-account, which is then audited by the Public Staff. Once the Commission has approved the Account Holder's compliance with the Portfolio Standard, the RECs are retired.

Creation Date: The date (DD/MM/YYYY) that a Certificate is created. Certificates are created upon acceptance of production data by the Account Holder, or if the production data passes all system validations, the Certificates will automatically create fourteen (14) days after the production data was uploaded into NC-RETS.

Customer-Sited Distributed Generation: A Renewable Energy Facility that is interconnected behind a retail customer meter and therefore not directly interconnected with either the distribution system or transmission system (including net metered facilities).

Directory of Account Holders: The Directory of Account Holders is a listing of all Account Holders registered with NC-RETS. This directory includes limited information for contacting each Account Holder and is available to the public via the NC-RETS website.

Directory of Renewable Energy Facilities and Energy Efficiency Projects: This is a listing of all approved Projects within NC-RETS.

Dynamic Data: Dynamic Data is variable information that is associated with a specific MWh produced or saved by a Project, such as Certificate Serial Number or Creation Date.

Electric Power Supplier: An organization that sells electricity to retail end users, such as investor-owned utilities, municipal utilities, and electric membership corporations. All Electric Power Suppliers in North Carolina must comply with the State's Portfolio Standard, although the requirements vary slightly for investor-owned utilities versus municipal utilities and electric membership corporations.

Forward Transfer: A transfer of Certificates arranged in advance to be effectuated on a specific future date.

Fuel Type: The kind of fuel or source of energy used to produce electric or thermal energy at a Renewable Energy Facility. See Appendix D for a list of eligible Fuel Types. This list was established by the North Carolina General Assembly when it enacted NC's Portfolio Standard.

General Account: This type of Account can hold, transfer (outgoing and incoming), and Retire Certificates for voluntary (non-compliance) reasons. This kind of Account can also open a Sub-account where RECs are created for a Renewable Energy Facility.

Generation Activity Log: The Generation Activity Log is an electronic ledger where energy production from Renewable Energy Facilities and energy saved by Electric Power Supplier energy efficiency programs is posted prior to Certificate creation. Each time production or savings data is received by NC-RETS for a particular Project, the date and quantity of qualifying MWhs produced or saved is posted to the Generation Activity Log. Adjustments received are posted likewise.

Inbox: Certificate transfers to an Account Holder are first posted in the Account Holder's Inbox. The Account Holder then either accepts or rejects the transfer. Upon acceptance, the Certificates are deposited in the Sub-account designated by the Account Holder.

Megawatt-hour (MWh): One thousand kilowatt-hours or 1 million watt-hours of energy. One MWh of energy produced by a qualifying fuel at a Renewable Energy Facility is required to create one Renewable Energy Certificate. One MWh of energy saved by an Electric Power Supplier's energy efficiency or demand side management project is required to create on Energy Efficiency Certificate.

Multi-fuel Facility or Generation Project: A Renewable Energy Facility that produces energy using more than one Fuel Type and might partially rely on a fuel that does not qualify for issuance of Certificates, See Section 4.2 below.

Nameplate Capacity: The maximum rated output of a generator, prime mover or other electric power production equipment under specific conditions designated by the manufacturer. Size classification in Megawatts (MW) is based on Nameplate Capacity.

NC-RETS Administrator: The NC-RETS Administrator is the entity under contract with the Commission to implement the NC-RETS Operating Procedures. The Commission selected APX to be the NC-RETS Administrator. The NC-RETS Administrator confers with Commission Staff, which seeks Commission concurrence, for exceptions to the NC-RETS Operating Procedures.

North Carolina Electric Power Supplier Account: This type of Account can hold, transfer (outgoing and incoming), and Retire Certificates. A North Carolina Electric Power Supplier Account can also register and maintain Projects and have Certificates issued to it for its Projects. A North Carolina Electric Power Supplier Account is the only kind of Account that can retire Certificates for compliance with NC's Portfolio Standard.

Outbox: After initiating a Certificate transfer, an Account Holder will see the Certificates in its Outbox. The Account Holder to whom the Certificates have been transferred will either accept or reject the transfer. If rejected, the Certificates will be returned to the Active Sub-account from which they were transferred. If accepted, the Certificates are transferred to the receiving Account Holder.

Portfolio Standard: The law enacted by North Carolina's General Assembly via Session Law 2007-397 that requires all Electric Power Suppliers serving retail customers in North Carolina to meet an increasing portion of their customers' electricity needs from renewable energy and conservation.

Prior Period Adjustment: An addition or subtraction made to a current Certificate issuance in order to correct for an under- or over-issuance of Certificates made in error in a prior period, most commonly due to inaccurate metering data.

Program Auditor Account: North Carolina regulators will use this Account to review Compliance Sub-accounts submitted by North Carolina Electric Power Suppliers and Utility Compliance Aggregators, as well as to view NC-RETS reports.

Project: A Project is either a Renewable Energy Facility or an Electric Power Supplier's qualifying energy efficiency programs (including demand-side management for municipalities and electric membership corporations).

Project ID: A unique NC-RETS identifier for a Project that is assigned by NC-RETS when the NC-RETS Administrator approves a Project for Certificate issuance in NC-RETS.

Project Name: Project Name is the name assigned to a Project when it is registered in NC-RETS.

Public Staff: The State agency charged with investigating Electric Power Supplier compliance with North Carolina's Portfolio Standard (among other things) and representing the using and consuming public in proceedings before the Commission.

Qualified Reporting Entity (QRE) Account: This Account type should be used for an NC-RETS Account Holder that reports meter readings and other generation data to the NC-RETS Administrator. Qualified Reporting Entities include Balancing Authorities, Electric Power Suppliers, a federal power agency or a municipal power agency. A QRE Account is assigned to each Project (except for those that are allowed to provide Qualified Estimates and Self-Reporting Facilities) and it is responsible for providing the Project's energy production information. NC-RETS tracks the specific Projects for which a QRE provides production information. A QRE Account cannot hold Certificates.

Qualifying Estimates: These are electric production estimates, based on generally accepted analytical tools such as PV Watts (www.pvwatts) for inverter-based solar photovoltaic Renewable Energy Facilities with a Nameplate Capacity of 10 kW or less. The facility owner shall document such estimates and retain such documentation for audit by the Commission and the Public Staff. Qualifying Estimates may be used to issue RECs in NC-RETS.

Qualifying Meter: This is a meter that provides energy production data of sufficient quality that it can be relied upon for the issuance of Certificates. For a Renewable Energy Facility that is interconnected to a Balancing Authority, it is the meter or data source that is used by the Balancing Authority for settlements. For Renewable Energy Facilities that are interconnected to an Electric Power Supplier's distribution system, it is the meter supplied by and read by the Electric Power Supplier. For a Renewable Energy Facility that is interconnected behind an Electric Power Supplier's meter at a customer's location, a Qualifying Meter can either be 1) an ANSI-certified meter that may be read and self-reported by the owner of the Renewable Energy Facility who shall comply with the Commission's meter testing requirements pursuant to Commission Rule R8-13; or 2) another industry-accepted, auditable and accurate metering, controls and verification system. For a combined heat and power system or solar thermal energy facility that has been approved by the Commission as a Renewable Energy Facility, the facility's useful thermal energy (excluding energy used to produce electricity) may be measured by an industry-accepted meter for measuring British thermal units (Btu). NC-RETS shall issue one Certificate for every 3,412,000 Btu of qualifying thermal energy.

Qualifying MWh: Energy that is produced by a Renewable Energy Facility via a fuel source or technology that qualifies it for the NC Portfolio Standard.

Renewable Energy Certificate (REC): See Certificates.

Renewable Energy Facility: An energy production facility that has been approved by the Commission as eligible to have some or all of its output count toward NC's Portfolio Standard. The owner of such a

Facility located in North Carolina is eligible to register that Facility in NC-RETS, where Certificates are issued for qualifying energy production.[1]

Responsible Party: An Account Holder who has been assigned the registration rights for a given Project. This assignment occurs outside of NC-RETS and gives the designated Account Holder *full and sole* management authority over the transactions and activities related to the Project within NC-RETS.

Retirement Sub-account: A Retirement Sub-account is used as a repository for Certificates that the Account Holder wants to designate as Retired and remove from circulation. Once a Certificate has been transferred into a Retirement Sub-account, it cannot be transferred again to any other Sub-Account.

Retirement of Certificates or Retirement/Retire: Retirement of Certificates is an action taken within NC-RETS to permanently remove a Certificate from circulation. There are two types of retirement: voluntary or compliance. Retirement may be initiated only by the Account Holder for Certificates in his/her own Sub-accounts. Voluntary retirement is effectuated by transferring Certificates into a Retirement Sub-account. For Electric Power Suppliers, compliance retirement occurs when RECs are placed into a Compliance Sub-account, and submitted for review to the Commission. RECs associated with an approved Compliance Sub-account are placed into retirement by Commission action.

Self-Reporting Facility: This is a Renewable Energy Facility or utility-sponsored energy efficiency or demand-side management Project for which the owner self-reports its output or energy savings. This includes 1) a customer-sited Renewable Energy Facility interconnected behind an Electric Power Supplier's meter that has either 1) a meter that meets ANSI standards and complies with Commission Rule R8-13, or 2) another industry-accepted, auditable and accurate metering, controls and verification system; 2) inverter-based solar facilities of 10-kWor less; 3) solar thermal facilities; and 4) combined heat and power facilities. Self-Reporting Facilities transmit their production data to the NC-RETS Administrator via the Self-Reporting Interface pursuant to Section 5.7

Self-Reporting Interface: This is a standard internet-based data entry portal that serves as the method for a Self-Reporting Facility, including energy efficiency and demand-side management Projects, to communicate dynamic data to the NC-RETS Administrator pursuant to Section 5.7.

Serial Number: NC-RETS assigns a Serial Number to each Certificate that it issues. The Serial Number contains embedded codes that explain when it was issued.

Static Data: Static Data describes the attributes of a Project and includes information related to the characteristics of the Renewable Energy Facility such as technology type, ownership and location.

Station Service: Station Service is the portion of electricity or thermal energy produced by a Renewable Energy Facility that is immediately consumed at that same facility in order to power the facility's pumps, etc., or to process fuel. Such energy is not eligible for issuance of Certificates.

User: Any person who has been granted access by an Account Holder to "use" its Account in NC-RETS, which may include viewing information, performing transactions and changing personal information. The Account Holder may at any time revoke the permissions granted to a User by notifying the NC-RETS Administrator. NC-RETS tracks the specific activities of each User through their unique login and password.

Utility Compliance Aggregator: An organization that assists an Electric Power Supplier or group of Electric Power Suppliers in demonstrating its compliance with NC's Portfolio Standard.

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[1] The owner of a Renewable Energy Facility that is located in South Carolina, which has its meter read by a NC Electric Power Supplier, may also register the Project in NC-RETS for the issuance of RECs.

1 Introduction

The Commission established the North Carolina Renewable Energy Tracking System (NC-RETS) to issue and track Renewable Energy Certificates (RECs) and Energy Efficiency Certificates (EECs). NC's electric utilities use NC-RETS to demonstrate compliance with the State's Portfolio Standard established under Session Law 2007-397. Renewable energy producers may register their facilities with the Commission. If approved, they can use NC-RETS to create RECs that meet the requirements of NC's Portfolio Standard.

NC-RETS uses verifiable energy production data from participating facilities to create one digital Certificate for each MWh (or thermal equivalent) generated from renewable energy. Electric Power Suppliers and Utility Compliance Aggregators use NC-RETS to track the results of qualifying energy efficiency and demand-side management customer programs operated by Electric Power Suppliers. NC-RETS and all related energy.production and customer program records are audited by the Public Staff of the North Carolina Utilities Commission. NC-RETS will integrate with all other REC tracking systems in the United States to allow for the import and export of RECs to and from North Carolina.

2 NC-RETS User Registration

2.1 Participation in NC-RETS

Any party is eligible to participate in NC-RETS, which means that any person can own RECs and track them in NC-RETS. NC-RETS includes many reports and links that are available to the general public. The Public Staff and the Commission use NC-RETS to audit compliance with NC's Portfolio Standard.

Electric Power Suppliers (or their Utility Compliance Aggregators) must use NC-RETS to demonstrate their compliance with NC's Portfolio Standard. An Electric Power Supplier establishes an Account in NC-RETS to hold RECs, including those that they acquire or generate and those associated with allocations from the Southeastern Power Administration (SEPA). Similarly, an Electric Power Supplier uses NC-RETS to document and track eligible energy savings via Energy Efficiency Certificates (EECs) from its qualifying energy efficiency and demand-side management programs. Each year, starting in 2011 for the 2010 compliance year, Electric Power Suppliers and Utility Compliance Aggregators will move RECs and EECs into a Compliance Sub-account, which will be audited to determine whether the organization complied with the Portfolio Standard.[1] Once the Commission determines that the organization has complied, those RECs will be permanently Retired, meaning they cannot be sold or reused for compliance.

NC-RETS issues and tracks Certificates originating from NC's Projects registered in NC-RETS and also tracks those Certificates that are imported into NC-RETS from other tracking systems in the United States. Organizations that operate Renewable Energy Facilities located in North Carolina and that want RECs associated with their facilities' output to be eligible to count toward NC's Portfolio Standard must participate in NC-RETS.[2] They use NC-RETS to create an Account for each facility where production data (meter readings or self-reported data, depending on the facility's size) or other criteria are uploaded, and RECs are issued. After arranging to sell RECs to a North Carolina Electric Power Supplier or Utility Compliance Aggregator, they will be able to use NC-RETS to transfer those RECs to the purchaser. In addition, NC-RETS has a Bulletin Board where they can post RECs that they would like to sell.

[1] Some municipal utilities and electric membership corporations (EMCs) have contracted with a power agency, GreenCo Solutions, Duke Energy, or Progress Energy, to act as a Utility Compliance Aggregator that will manage and report compliance with the Portfolio Standard on behalf of that municipal utility or EMC.

[2] If a facility already participates in PJM's Generation Attribute Tracking System (GATS), it does not need to also participate in NC-RETS. This may be the case if the facility is located in Dominion's service territory.

Utility organizations that read the production meters for any Renewable Energy Facilities located in North Carolina use NC-RETS to provide those meter readings on an on-going basis. NC-RETS uses those meter readings to create one REC for each qualifying MWh of energy produced by a Renewable Energy Facility.[1]

Balancing Authorities (Duke Energy and Progress Energy) that provide energy balancing and accounting at the transmission level, use NC-RETS to upload monthly production data for Renewable Energy Facilities that are interconnected to their transmission systems.

2.2 Establishing an Account

Any person or entity wanting to participate in NC-RETS must establish an Account. Accounts should be established in accordance with the timeline for certificate creation (see Section 6.2) to ensure Certificate eligibility.

Registrants will provide basic Account registration information, such as Account Holder name, address and contact information, to the NC-RETS Administrator through a secure web-page on the NC-RETS website[2] and agree to the Terms of Use. (The Terms of Use are available for review on the NC-RETS website, www.NCRETS.org, under "Documents.") See Appendix A for step-by-step instructions. The NC-RETS Administrator reviews the Account application and may request more information before approving or rejecting the application. An Account remains active until terminated. Termination can be initiated by the Account Holder by notifying the NC-RETS Administrator. Accounts can also be terminated if an Account Holder fails to pay the NC-RETS fees or is otherwise in default under the Terms of Use. The Terms of Use describe these issues, as well as additional important terms, and should be read and understood by anyone applying to be an Account Holder.

Account Types and Sub-Account Structure
There are four (4) types of Accounts in NC-RETS:

- **North Carolina Electric Power Supplier Account:** This type of Account can hold, transfer (outgoing and incoming), and Retire Certificates. A North Carolina Electric Power Supplier Account can also register and maintain Projects and have Certificates issued to it for its Projects, including energy efficiency and demand side management programs. A North Carolina Electric Power Supplier Account is the only type of Account that can retire Certificates for compliance with NC's Portfolio Standard. An organization that provides compliance services for another Electric Power Supplier is called a Utility Compliance Aggregator. Only Electric Power Suppliers and Utility Compliance Aggregators are eligible to establish a North Carolina Electric Power Supplier Account.

In 2010, when North Carolina Electric Power Suppliers (and Utility Compliance Aggregators) first register to open an Account in NC-RETS, they will be required to input (on the Account registration screen) their organization's 2009 North Carolina retail sales (in MWh). As soon as NC-RETS generates the Account Holder's first NC-RETS bill on September 1, 2010, the Account Holder's "prior year retail sales" field will be locked. NC-RETS will use the locked sales data to calculate bills from September 2010 through June 2011. In June of 2011 and each subsequent year, the Account Holder must enter the "prior year's retail sales" data. For more details, please refer to the Fee Schedule, which is on-line at www.ncrets.org.

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[1] "Qualifying MWh" is one that was produced by a fuel that qualifies under Session Law 2007-397 at a facility that has been registered with the Commission as a Renewable Energy Facility. NC-RETS does contain the functionality to apply multipliers in exceptional cases such as the Duke off-shore wind turbines, where one MWh will create more than one REC.

[2] http://www.NC-RETS.org

- **General Account:** This type of Account can register Projects and have RECs issued to it for its Projects. (Before creating Certificates in NC-RETS, a Renewable Energy Facility must first register with the Commission.) A General Account can hold, transfer, and Retire Certificates (for reasons other than compliance with NC's Portfolio Standard). The Account Holder for a Renewable Energy Facility Project can seek eligibility for its facility with Green-e Energy or Low-Impact Hydro Institute (LIHI). If accepted by those organizations, NC-RETS can indicate such eligibilities on Certificates issued for output from the facility.

- **Qualified Reporting Entity (QRE) Account:** An Account Holder with a QRE Account is assigned to a Project and is responsible for providing energy production information such as monthly meter readings for that Project. A QRE Account cannot hold Certificates. The QRE uses its NC-RETS Account to upload meter reads or monthly settlement data for each Project to which it is assigned. An Electric Power Supplier should have a QRE Account if it reads the production meter for Renewable Energy Facilities, or if it is a Balancing Authority.

- **Program Auditor Account:** This type of Account will allow Commission and Public Staff to perform compliance review and auditing of program data as needed.

Accounts that can hold Certificates (North Carolina Electric Power Supplier and General Accounts) are given three types of Sub-accounts automatically by default when their Account is approved (Active, Retirement and Export Sub-accounts). An Active Sub-account is used to organize Certificates based on an organization's business structure as desired. The default Retirement Sub-account is used to Retire Certificates for voluntary reasons (that is, reasons other than compliance with NC's Portfolio Standard). The Export Sub-account is used to transfer Certificates to another tracking system. The Account Holder has the ability to rename these default Sub-accounts and create as many additional Active and Retirement Sub-accounts as necessary to meet their organization's needs. Retirement Sub-accounts cannot be renamed if they hold Certificates. When Certificates are issued, they are placed into an Active Sub-account that was designated when the Project was registered with NC-RETS. When an incoming Certificate transfer is pending, the recipient Account Holder identifies the Active Sub-account into which the Certificates will be deposited. Each Account Holder will be able to view a listing of Certificates held in each Sub-account and their attributes (e.g. static Project details, eligible program certifications and Certificate origination details).

Accounts that can hold Certificates also have a single Bulletin Board Sub-account, used to post Certificates for sale on the NC-RETS Bulletin Board.

Each Account and Sub-account has a unique identification number. For ease of reference, Account Holders may attach aliases to Sub-accounts (e.g., by customer or by product name).

North Carolina Electric Power Suppliers and Utility Compliance Aggregators will have the ability to create Compliance Sub-accounts. Compliance Sub-accounts can only be used to Retire Certificates for the Portfolio Standard. A Compliance Sub-account is established for a specific compliance year, and the Account Holder must designate whether the Sub-account is subject to the compliance obligations of an electric public utility or the compliance obligations of a municipality / electric membership corporation or a group of municipalities / electric membership corporations.

2.3 Deposits to Active Sub-Accounts

There are four ways that Certificates are deposited into an Active Sub-account.

(a) Within an Account, Certificates can be transferred from one Active Sub-account or Bulletin Board Sub-account to another.
(b) An Account Holder can accept a transfer of Certificates from another Account Holder.
(c) Certificates can be generated by a Project and deposited by the NC-RETS Administrator into the Sub-account assigned to the Project.

(d) Certificates can be transferred into a Compliance Sub-account prior to the Compliance Sub-account being submitted for review by the Commission and Public Staff.

2.4 Transfers from Active Sub-Accounts

There are two ways to withdraw or remove Certificates from Active Sub-accounts:

(a) Transfer the Certificates to the Sub-account of another Account Holder.
(b) Transfer the Certificates to another of the Account Holder's own Sub-accounts (Active, Retirement, Export, Compliance, or Bulletin Board Sub-account).

Certificates that have been deposited in a Compliance Sub-account cannot be moved out of that Sub-account once the Electric Power Supplier or Utility Compliance Aggregator submits the associated Portfolio Standard Compliance Report to the Commission for review.

2.5 Retirement Sub-Accounts

A Retirement Sub-account is used as a repository for Certificates that the Account Holder wants to designate as voluntarily retired. There are three ways that Certificates are deposited in a Retirement Sub-account:

(a) Within an Account, Certificates can be transferred from an Active Sub-account or a Bulletin Board Sub-account to a Retirement Sub-account.
(b) An Account Holder can accept a transfer of Certificates from another Account Holder directly into a Retirement Sub-account.
(c) Certificates can be transferred from a Compliance Sub-account to a Retirement Sub-account prior to the Compliance Sub-account being submitted for review by the Commission and Public Staff.

An Account Holder choosing to retire a Certificate or a block of Certificates will use the transfer screen to identify the quantity of Certificates to Retire and the reason for Retirement. The Account Holder must select the Retirement Sub-account to which the Certificates will be deposited. The Retirement Sub-account will show the Serial Numbers of the Certificates Retired, the date of Retirement and the reason for Retirement. In addition, there will be a mechanism to view the Project characteristics and Certificate fields associated with the Retired Certificates. *Once Certificates are Retired, they cannot be moved or transferred out of the Retirement Sub-account to any other Sub-Account or Account Holder.*

NC-RETS validations ensure that Certificates deposited in a Retirement Sub-account are no longer transferable to another party or another Sub-account. NC-RETS reports allow Account Holders to show evidence of the Retirement.

2.6 Compliance Sub-Accounts

A Compliance Sub-account will be available to North Carolina Electric Power Suppliers and Utility Compliance Aggregators only. These entities can have one electric public utility Compliance Sub-account per compliance year and an unlimited number of municipal utility / electric membership corporation type of Compliance Sub-accounts per year. For example, for 2010, an Electric Power Supplier can have one Compliance Sub-account for itself (as an electric public utility) and 1 or more for each municipality/coop or group of such electric power suppliers for which it provides compliance reporting. Each Compliance Sub-account will be subject to the statutory requirements for either: 1) an electric public utility, or 2) a municipal utility/electric membership corporation (cooperative). Certificates in a Compliance Sub-account will be in a "pending retirement status" while the State Program Auditor/Regulator accesses it via a compliance report for audit. When that review and the related regulatory proceeding are complete, the Commission will use NC-RETS to finalize Retirement of the Certificates into a permanent Retirement status. State Program Auditors will see the related Compliance Report from their own Accounts.

There are two ways that Certificates are deposited into a Compliance Sub-account:

(a) Within an Account, Certificates can be transferred from an Active Sub-account or a Bulletin Board Sub-account to a Compliance Sub-account.
(b) An Account Holder can accept a transfer of Certificates from another Account Holder directly into a Compliance Sub-account.

The NC-RETS Administrator is not responsible for the Retirement of Certificates by Account Holders, as it relates to voluntary or compliance-related Retirement deadlines or otherwise.

2.7 Transfers between Accounts

North Carolina Electric Power Supplier and General Account Holders may transfer Active Renewable Energy Certificates to other Account Holders. Certificates will be specified by their Serial Numbers. The Account Holder will select the recipient from a pull-down list of Account Holders. After the transfer has been initiated, the Certificates that are pending transfer will be marked as "transfer pending" in the Account Holder's Outbox. This will have the effect of "freezing" the Certificates so that they cannot be moved to another Sub-account or to another Account Holder.

After the transfer has been initiated, NC-RETS will send an electronic notification of the request to transfer Certificates to the proposed recipient. The transfer recipient can review the Certificate transfer details from the Account Holder's Outbox and must confirm or reject the transfer within fourteen (14) calendar days of when it was requested by the transferor. If rejected, the Certificates will be deposited back into the originating transferor's Sub-account. If confirmed, the transfer recipient must designate the Sub-account to which the Certificates are to be delivered. As soon as the recipient has confirmed or rejected the transfer, NC-RETS will send an electronic notification to the transferor indicating the action taken. The transferor may cancel any transfer before such transfer has been confirmed by the recipient by withdrawing the transfer from the Account Holder's Outbox in NC-RETS. If the transfer is withdrawn, NC-RETS will notify the recipient of the action.

2.8 Compatible Tracking Systems

NC-RETS is set up to accept transfers of eligible Certificates from compatible tracking systems. A compatible tracking system is a system that has set-up up a process with NC-RETS on how to handle imports and/or exports and implemented the required technology. NC-RETS is working towards setting up imports and exports with all registries that track generation from facilities that have been approved by the NC Commission. Appendix F lists the compatible tracking systems at the time of NC-RETS launch. This list is also posted at www.ncrets.org and will be updated as more registries are deemed to be compatible.

2.8.1 Imports from other Tracking Systems

Only Certificates from facilities and fuel types that have been approved by the Commission can export Certificates to NC-RETS. In order to import a Certificate from another tracking system the Account Holder in the exporting tracking system will need to follow that tracking system's procedures for an export. This generally includes designating a specific batch of Certificates for export and designating the importing registry (i.e. NC-RETS) and the importing NC-RETS Account Holder (Account ID and name).

The NC-RETS Account Holder will see the imported Certificates in their Inbox module with a note stating that these are import Certificates. The Certificate transferor will be NC-RETS Administrator.

The imported Certificates will have a unique Serial Number that references the originating registry instead of NC-RETS. The Certificate data screen will also contain the original Serial Number from the issuing registry. All Projects from which Certificates have been imported into

NC-RETS will be listed on the public 'Imported Facility Report.' No information about the quantity transferred and the parties involved in the transaction will be publicly posted.

Tracking systems track fuel types differently. Certificates in NC-RETS will issue with the fuel types used by NC-RETS and that correspond to fuel types approved by the Commission.

2.8.1.1 Multi-fuel Facilities that use Swine and/or Poultry Waste

Only NC-RETS and the North American Renewables Registry (NAR) currently can track swine waste and poultry waste Certificates separately from other kinds of biomass used in a Multi-fuel Facility. If a NC-RETS Account Holder is planning to import Certificates from a Project that is (1) registered in a tracking system other than NAR, and, (2) using more than one type of biomass, and, (3) where one or more of the fuels is swine and/or poultry waste, then additional procedures are needed to correctly differentiate swine and/or poultry waste Certificates from other biomass Certificates. NC-RETS Account Holders contracting for such Certificates should contact the NC-RETS Administrator before the export is initiated from the exporting tracking system. The NC-RETS Administrator and the Commission will ask the NC-RETS Account Holder for Project specific information (i.e. fuel deliveries, generation data etc.) needed to substantiate that swine and/or poultry waste generated the energy associated with the RECs.

If the Project only uses one biomass fuel (i.e. swine waste or poultry waste) the above procedure is not needed.

2.8.2 Exports to other Tracking Systems

In order to export a Certificate to another tracking system the NC-RETS Account Holder will designate a specific batch of Certificates for export and designate the registry and Account Holder (Account ID and Name) to whom the Certificates should be delivered.

After the transfer has been initiated, it will show up in the NC-RETS Account Holder's Outbox module as "Pending." It will remain "Pending" until the NC-RETS Administrator confirms that the Certificates are eligible for export to the importing tracking system.

3 Access to Accounts and Confidentiality

3.1 Account Access

An Account Manager is established as part of the Account registration process. The individual listed in the initial Account application will be considered the Account Manager and have the ability to setup and manage any additional User logins and login privileges for his or her organization. The Account Manager will have full access to the organization's Account. The Account Manager can customize login permissions to allow view-only access to information or to allow the User to perform activities such as transfers and submitting/updating information. Such privileges can also be further attached to specific Sub-accounts or Projects. This provides Account Holders with significant flexibility when assigning Users to specific tasks or roles. User login setup can be done during the Account registration process or at any time the Account Manager wishes to add Users to the Account. The Account Manager supplies contact information for each User and designates their login name and password.

NOTE: The NC-RETS Terms of Use shall apply to any person who receives access to an NC-RETS Account or Sub-account from an Account Holder or Account Manager.

Once a User login is established, NC-RETS sends an email to the login contact specified by the Account Manager with details on the individual's login name. The Account Manager is required to communicate the password to the new User. Upon logging into NC-RETS for the first time, the new User is prompted by NC-RETS to change his or her password. The new User can then perform the functions or view the information per the permissions granted by the Account Manager. The Account Manager or NC-RETS Administrator may at any time remove or add permissions to a User by using the Account administration screens.

The NC-RETS My Event Log report tracks and displays all actions performed within the Account by login name and timestamp. Account Managers have access to the My Event Log report for their Account and Sub-accounts.

3.2 Levels of Account Access

When an Account Holder creates logins for additional Users, the Account Holder assigns to the User one of two levels of specific access rights:

3.2.1 Account Holder – Supervisor

When completing the login profile for a new User, the Account Manager can assign them "Account Holder – Supervisor" privileges. Such a new User is able to register Projects, manage Certificates, and create additional logins, if necessary. The Account Manager can also give this User a subset of these privileges if needed.

3.2.2 Account Holder – View Only

When completing the login profile for a new User, the Account Manager can assign the User "Account Holder – View Only" privileges. This provides the User with limited view rights. The Account Manager will then identify the specific Sub-accounts and Certificates that the User will be able to access and view.

3.3 Confidentiality

As stated in the Privacy Policy [www.ncrets.org] and the Terms of Use, certain Account information is held confidential. Account information is only used and released by NC-RETS in aggregate through the public reporting process.

4 Project Registration

Within NC-RETS and all related NC-RETS documents, the term "Project" is used to refer both to (1) a generating Project, which is a Renewable Energy Facility registered with the Commission, accepted by the NC-RETS Administrator and for which NC-RETS issues Certificates, and (2) an energy efficiency Project, which is registered with NC-RETS by an Electric Power Supplier for its energy efficiency or demand-side management programs, or a Utility Compliance Aggregator on behalf of an Electric Power Supplier. (Note: only municipal utilities and electric membership corporations can use their demand-side management programs for Portfolio Standard compliance.) Once a Project is registered within NC-RETS, monthly production data or annual energy savings can be uploaded to NC-RETS to create Renewable Energy Certificates or Energy Efficiency Certificates. Step-by-step instructions for registering a Project can be found in Appendix B.

4.1 Registering a Project

To ensure that double-counting does not occur, Renewable Energy Facilities registered in NC-RETS must have 100% of their output tracked by NC-RETS (with the exception of imported Certificates). If a Renewable Energy Facility or an associated contract for its production was registered in another tracking system at one point, the NC-RETS Administrator should be notified of this during the registration process and the Account Holder should be prepared to provide documentation to prove the Renewable Energy Facility (and, if applicable, its associated contracts) have been removed from the previous tracking system.

The owner, or Responsible Party, of a Renewable Energy Facility must first establish an Account within NC-RETS as described above and then register a Project as a Renewable Energy Facility or an Energy Efficiency Project, as the case may be, before NC-RETS can certify and issue Certificates attributable to it. The Account types that can register Renewable Energy Facilities are the NC Electric Power Supplier Account and the General Account. Only the NC Electric Power Supplier Account can register energy efficiency Projects in NC-RETS.

To register a Renewable Energy Facility or an energy efficiency Project (which would include DSM programs), the owner or the Responsible Party must:

- Have an approved Account in NC-RETS;
- Have registered with the Commission and received approval from the Commission for the Renewable Energy Facility; and
- Submit a completed on-line registration form containing information related to the characteristics of the Renewable Energy Facility or energy efficiency Project. (Note: Many Electric Power Suppliers will have several energy efficiency programs – their energy savings will be uploaded into one Project.)

The NC-RETS Administrator will review the information provided and request additional information as needed before approving a Renewable Energy Facility registration request in NC-RETS.

4.2 Multi-fuel Renewable Energy Facility Project

A Multi-fuel Renewable Energy Facility Project is one that produces energy using more than one Fuel Type. A Multi-fuel Renewable Energy Facility Project can use a renewable fuel with a fossil fuel or use multiple types of renewable fuels. Such facilities must register with NC-RETS as a Multi-fuel Renewable Energy Facility Project. If the relative quantities of energy produced from each fuel cannot be measured or calculated, and verified, the facility is not eligible to register as a Multi-fuel Renewable Energy Project in NC-RETS.

Each Certificate issued for a Multi-fuel Renewable Energy Facility Project will reflect only one Fuel Type. The total number of Certificates issued for a Fuel Type in a reporting period will be proportional to the energy output from that Fuel Type for that reporting period.

Each NC-RETS Account Holder or Responsible Party that has registered a Multi-fuel Renewable Energy Facility Project must report monthly to the NC-RETS Administrator the proportion of energy output per Fuel Type, by MWh or Btu, generated by the Multi-fuel Renewable Energy Facility Project during that month, calculated according to the applicable provisions of Section 0. Though energy produced from all Fuel Types must be reported, NC-RETS will only issue Certificates for the qualified renewable energy. Certificates will not be issued until such information is provided by the Account Holder or Responsible Party.

The procedures and methodologies used by the Account Holder or Responsible Party to calculate the contribution of each Fuel Type should be retained by the Account Holder or Responsible Party according to Commission rules, and will be subject to audit by the Public Staff and the Commission.

To import Certificates from multi-fuel generators, see Section 2.8.1.

4.3 Verification of Static Data Submitted During Project Registration

Upon completion of the Renewable Energy Facility Project registration process, the NC-RETS Administrator will review attestations, Energy Information Administration reports and other data sources to verify the information provided by the Account Holder.

In the event data submitted is found to be incorrect or if there is a discrepancy between the information submitted during the on-line registration process and the materials provided to verify the information, the NC-RETS Administrator will notify the registrant that the information could not be positively verified. A process of either correcting the registration form, or withdrawing the registration form, or providing proof that the information on the registration form is correct will ensue between the NC-RETS Administrator and the registrant until the NC-RETS Administrator is satisfied that the information provided meets NC-RETS standards for accuracy. If any issues arise, the NC-RETS Administrator will raise them with the Public Staff in case a site visit is needed to verify the legitimacy of Project registration and generation data.

4.4 Updating Static Data

After the initial Project registration in NC-RETS, Account Holders should continually notify NC-RETS of the following actions or occasions that will have the effect of changing Static Data tracked by NC-RETS:

(a) A change in Fuel Type for a Renewable Energy Facility, and the date on which the change occurred, within thirty (30) calendar days from when the change is implemented. (The Account Holder should also notify the Commission, referencing the docket number from its registration order.)
(b) A change in Project ownership, and the date on which the change occurred, within thirty (30) calendar days after the change occurs. A change in ownership must be confirmed by a letter signed by both the prior and new owners of the Project, and provided to the NC-RETS Administrator. Neither NC-RETS nor the NC-RETS Administrator will be responsible for depositing Certificates into an Account that no longer represents a Project if the incorrect deposit occurs as a result of a lack of notification by the prior and new owners of the Project. Parties should arrange for a meter-reading to occur coincident with the ownership change. This meter read will be used to determine the final REC issuance to the original owner. Subsequent production data will be used to generate RECs that will be issued to the new owner. (A facility owner must notify its QRE of any change of ownership. A new owner must also register the facility with the Commission.)
(c) A change in a Project's eligibility for any programs or certification tracked by NC-RETS. This must be communicated by the Account Holder before any Certificates affected by the change are issued or within thirty (30) calendar days after the change occurs, whichever is sooner.
(d) A change to any of the "essential generating characteristics" of the Project.

4.5 Misrepresentation of Static Information:

Account Holders can be removed from NC-RETS for cause, including misrepresentation of Static Data. NC-RETS reserves the right to withhold issuing Certificates, to freeze a Sub-account or Account associated with a particular Project, or to withhold participation in NC-RETS for Projects that have willfully misrepresented Static Data. If the NC-RETS Administrator has cause to suspend the Project's participation in NC-RETS, no Certificates will be created while the Project is under suspension. While under suspension, metering data may continue to be uploaded to the Project by the QRE but it will not contribute to Certificate creation. Upon removal of the suspension, Certificate issuance can proceed.

4.6 Terminating a Project's Participation in NC-RETS

If a Project's owner or Responsible Party wants to remove a Project from NC-RETS, they can do so by notifying the NC-RETS Administrator and specifying the following:

(a) The date the Project should be/will be removed from NC-RETS;[1]
(b) The name of the Project's Qualified Reporting Entity, if applicable; and
(c) The Sub-account to which Certificates should be deposited (if the usual Account for deposit is being closed as well).

[1] This is the same as the final date of generation for which Certificates are to be issued.

NC-RETS will issue Certificates for a Project up to the date of Project termination as instructed by the Project's owner or Responsible Party. No Certificates will be issued for adjustments that occur after the termination date. If the Account to which the Project is linked is also closed at the same time, the Project's owner or Responsible Party must also specify the Account to which any remaining Certificates that have not yet been issued should be deposited. Failure to do so will result in loss of Certificates.

4.7 Changing the Account (Owner) with which a Project is Associated

If the Project's owner or Responsible Party wants to change the Account with which a Project is associated, they can do so by notifying the NC-RETS Administrator and providing the information requested by the NC-RETS Administrator, including, but not limited to:

(a) The new Account number with which the Project will be associated;
(b) The date the change will be effective; and
(c) Any documentation required for legal purposes or to meet certification requirements.

Certificates from the Project that were created up to the day the Account change takes effect will remain in, or be deposited into, the Account that the Project was associated with at the time the generation occurred. For example, if a Project's owner changes the Account with which the Project is associated from Account A to Account B, and the change is effective on March 1, then the Certificates relating to generation that issued prior to March 1 will be deposited into Account A. Any issuance from the Project after March 1 will go into Account B.

The NC-RETS Administrator will need written confirmation of this change from both parties involved in the Project transfer in order to implement the change. When changing the Account with which a Project is associated, there cannot be any time when the Project is not associated with an Account. If there is such a lapse, this will be treated as a deregistration/re-registration of the Project instead of a change of Account. (Note: Project owners also need to inform the Commission of a change in ownership, referencing the docket number that the Commission assigned to their registration order.)

5 Dynamic Data in NC-RETS – Generation Data – Role of Qualified Reporting Entity

5.1 Qualified Reporting Entity (QRE) Guidelines

A QRE is a Balancing Authority, an Electric Power Supplier, or a federal or municipal power agency. They provide production data to NC-RETS for Renewable Energy Facilities at least monthly. A Balancing Authority provides data consistent with its monthly settlements process. Other QREs provide data from routine meter readings. Each QRE adheres to the following guidelines:

1. A QRE that must also comply with the Portfolio Standard shall demonstrate that its employees who are responsible for reporting facility production data are separated organizationally from its employees who are responsible for Portfolio Standard compliance. "Separate from" means that the QRE employee(s) work in a separate department, division, section or unit that is not responsible for planning for, demonstrating or assuring Portfolio Standard compliance. The NC-RETS Administrator may make exceptions for extremely small Electric Power Suppliers after consulting with the Commission. However, in no event shall the employee who creates or uploads production data be the same employee who uses NC-RETS for compliance purposes.

2. A QRE creates a QRE Account in NC-RETS. The NC-RETS Administrator will validate the application information that it submits.

3. Upon approval, each QRE is added to the list of QREs available for selection by a Project. Upon registration, a Project will have to provide a unique ID that is assigned by the QRE, which links its facility to the QRE. NC-RETS will provide each QRE with a list of the Projects that have selected it.

4. A QRE will at least monthly provide electricity production data to NC-RETS that is inherently reliable and auditable.

5. Reported electricity production data shall be financial settlement quality data from revenue quality meters, which would include those that meet ANSI-12 standards.

6. Each QRE shall upload data to NC-RETS. The QRE must use a valid active NC-RETS login and password associated with its NC-RETS QRE Account. After logging into the Account, the QRE Account Holder should locate the Meter Data Loading module. To locate the desired generation output file, the User selects the Meter Data Loading module's "browse" button to display a pop-up screen where the User can locate the desired file on computer or network drives. After selecting a file, the User selects the "Upload Now" button to upload the file. The file must be formatted in ASCII Text with data fields delimited by commas (Comma-Separated Value (CSV) format).

   The following example shows a conforming input file.

   NCRETSPROJECTID,REPORTINGENTITYID,VINTAGE,FROMDATE,TODATE,TOTALMWH
   114,2A58A68,08/2010,08/01/2010,08/31/2010,100

   The fields are as described in the following table:

Field Name	Data Type	Description
NCRETSPROJECTID	Integer	Unique NC-RETS identifier for the Project assigned by NC-RETS upon Project approval.
REPORTINGENTITYID	Integer and Character(50)	Unique identifier for the Project assigned by its QRE from the QRE's internal systems.
VINTAGE	Numeric Character(7)	Month and year of production, formatted as MM/YYYY for any month in the current reporting period
FROMDATE	Numeric Character(10)	Begin month-day-year of production output period formatted as MM/DD/YYYY
TODATE	Numeric Character(10)	End month-day-year of production output period formatted as MM/DD/YYYY
TOTALMWH	Floating decimal	Total MWhs for reporting period, with three spaces beyond the decimal

A current period output file can be loaded as many times as needed adhering to the following restrictions. (1) After an Account Holder has explicitly accepted the posted output data, NC-RETS will not accept re-loaded data for the same production period. NC-RETS will reject an attempted re-loaded. If the Account Holder has not yet accepted, the QRE can re-load the data, the previous data will be over-written and the Account Holder will receive notification of new data being posted. Otherwise, the QRE should contact the NC-RETS Administrator, who can re-load the file if it is appropriate to do so. (2) If NC-RETS has accepted the data or the Account Holder has disputed the data, and no Certificates have yet issued, a QRE can re-load the data. In all other instances, the QRE should work with the NC-RETS Administrator if it believes data needs to be re-loaded.

NC-RETS will validate a Project's uploaded data before posting the output into the NC-RETS data base. When all validations[1] are successfully completed, the data is loaded into the database and can be seen in a Project's Generation Activity Log. If the Project fails to produce energy in a given month, a QRE should report by uploading "zero" to be accepted by the Account Holder. NC-RETS then notifies the Account Holder via email that generation output has been loaded for the Project, and the data is available to be reviewed for approval or dispute.

5.2 Generation Data Requirements

NC-RETS will not create Certificates for generation supplying Station Service. Data used to issue Certificates for Renewable Energy Facilities must be derived from a Qualifying Meter or Qualifying Estimate and communicated to the NC-RETS Administrator.

For Renewable Energy Facilities whose output is settled monthly by a Balancing Authority, a "Revenue-Quality Meter" is the data source used by the Balancing Authority for settlements. The data must be electronically collected by a meter data acquisition system, such as an MV-90 system, or pulse accumulator readings collected by the Balancing Authority's energy management system, and verified through a Balancing Authority checkout/energy accounting or settlements process that occurs monthly. The preferred source for the data is a meter data acquisition system. If the Balancing Authority does not have an electronic source for collecting revenue meter data, then manual meter reads will be accepted.

When a QRE submits generation data (either manually entered or uploaded via file) NC-RETS validates the data to verify its engineering feasibility. To perform the validation, NC-RETS uses the following required variables from the Generating Project Registration screen:

- Nameplate Capacity
- Capacity Factor or Maximum Annual Energy

Data validation is performed for both current period reporting and Prior-Period Adjustment reporting, regardless of whether the data is loaded as a file or entered manually in the Project's Self-Reporting Interface. To determine the feasibility of the submitted data, NC-RETS will use the following equations:

For those Projects with a registered "Capacity Factor":
(Nameplate Capacity) • (Capacity Factor) • (number of hours in the duration) • (1.02)

For those Projects with a registered "Maximum Annual Energy":
(maximum annual energy)/(8640 hours in a year)] * (number of hours in the duration) * (1.02)

The number of hours in the duration is based on the duration of the generating period each time the information is reported on the Project. To determine the duration value, NC-RETS will calculate the number of hours in the generating period (for example, the number of hours in the generating period with a Begin Date of January 1, 2006 and an End Date of January 31, 2006 would be 744). The 1.02 will allow for a margin of error.

If the validation is successful, and the reported energy production is less than or equal to the maximum feasible generation for the facility, the data becomes available to the Account Holder to review and then accept, or dispute. If the Account Holder accepts the data, it will be included in the next Certificate issuance cycle. For Prior-Period Adjustments, the data will contribute to the next Certificate issuance after it was accepted (either by the Account Holder, or auto-accepted by NC-RETS).

[1] Validations include correct assignment of QRE, assessment of engineering feasibility of output, potential overlap of reporting period with prior uploads, data exceeds 31 days reported for a given vintage, and whether data for a previous period remains subject to dispute.

If the loaded data fails the engineering feasibility validation, the QRE will be prompted with a "soft" warning as to the failed validation. The QRE has the ability to continue posting the data by selecting the "continue" button on this pop-up screen. If the QRE wishes to continue posting data, NC-RETS will send an automated email to both the NC-RETS Administrator and the Account Holder that the data loaded for their Project has failed the engineering feasibility validation, but that the QRE has decided to have the data posted to the database anyway. The notification will also state that the data has a status of "NC-RETS Pending" until either corrected, or approved by the NC-RETS Administrator. Data with this status will not contribute to Certificate creation. The QRE can instead decide to not post the data to the database as a result of the failed validation by selecting the "cancel" button on this same pop-up screen. Selecting cancel will discontinue the data loading process for the Project in question and no notifications will be sent.

For all loaded data, the NC-RETS Administrator will have a report "Engineering Feasibility Estimate Calculations Report" which will list all Projects that have had data loaded, the amount of output loaded, and the feasibility pass/fail result.

NOTE: Failed validation for a single facility does not result in a failure to load the entire file – only the data for the facility that failed the validation.

5.3 Measurement of Generation and Adjustments

The output from each Renewable Energy Facility Project registered in NC-RETS will be measured at the point of interconnection to the transmission or distribution company's facility. Losses occurring on the bulk transmission or distribution systems after the metering point are not reflected in the Certificates created. NC-RETS will not create Certificates for that portion of the generation that is used to supply Station Service, and therefore, generation data should also be netted of Station Service supplied from the generator's side of the point of interconnection. For Renewable Energy Facilities also serving onsite loads, NC-RETS will create Certificates for the on-site load distinct from Station Service, if the facility's owner or Responsible Party can provide evidence that the metering used is capable of distinguishing between on-site load and Station Service. If adjustments are needed, due to metering, reporting, error or any other reason, the QRE must report the adjustment as soon as possible to the NC-RETS Administrator. If Certificates have not yet been created for the original generation amount to which the adjustment applies, the Certificate or debit will be posted to the Generation Activity Log, and will be reflected in the number of Certificates created. If Certificates have been created, the adjustment will be treated as a Prior Period Adjustment described below in Section 5.4.

5.4 Prior Period Adjustments

Adjustments can be requested by an Account Holder, including Self-Reporting Facilities, or a QRE, after the data is reported and used to issue Certificates in NC-RETS. These adjustments are known as Prior Period Adjustments. The Account Holder accesses the Project Output Data Review screen to submit an adjustment to the NC-RETS Administrator. If accepted by the NC-RETS Administrator, the Certificate or debit to the generation volume reported in the current month will post to the Generation Activity Log. Consequently, the adjustment will be realized when Certificates are next issued. If new Certificates are created, the vintage of the Certificates shall reflect the actual generation period. NC-RETS will not accept adjustments for generation reported more than one year prior.

5.5 Notification of Adjustments

The Account Holder will be informed of all positive or negative adjustments once the adjustment has been posted to the Generation Activity Log. Once NC-RETS informs the Account Holder of a need for adjustment, the Account Holder then has fourteen (14) calendar days to dispute or accept the adjustment. If after fourteen (14) days the Account Holder has failed to respond, the NC-RETS Administrator will automatically accept and create the adjustment.

5.6 Data Collection Procedure

Energy-generation data should be reported within 30 days of the meter read and will be accepted by the NC-RETS Administrator on an ongoing basis. Currently, NC-RETS can accommodate data in batches that contain up to 31 days of production data. [In order to conform to Commission rules, the NC-RETS Administrator will pursue changes such that NC-RETS will be able to accommodate 35 days worth of production data.] Data files are to be electronically transmitted to NC-RETS using a secured protocol and a standard format specified by the NC-RETS Administrator. The data shall reflect, at a minimum, the month and year of the generation, monthly accumulated MWhs for each NC-RETS Project ID and the associated NC-RETS and Project ID(s) for each Project. The owner of the Generating Project, as the owner of the metered data, or the Responsible Party, has the responsibility to direct the QRE to release generation data to NC-RETS.

The data must be transmitted by a single entity, which must be either (1) a QRE Self-Reporting Facility.

5.7 Special Requirements for Self-Reporting Facilities Only

A Self-Reporting Facility must enter actual cumulative meter readings measured in kWh / MWh or Btu (which will be converted to MWh) and the date of the meter reading via the Self-Reporting Interface. Actual cumulative meter readings must be entered no less frequently than annually. If a Self-Reporting Generator chooses to report data in cumulative over the course of multiple months (for example, 01/2010-06/2010), it can do so by uploading the data for the most recent vintage month (06/2010) and providing evidence of the monthly breakdown quantity to the NC-RETS Administrator. Self-Reporting Facilities that do not enter meter readings via the Self-Reporting Interface as required will receive a reminder notice by email from the NC-RETS Administrator. Self-Reporting Facilities risk having their Project de-activated in NC-RETS if they do not provide meter readings at least annually.

5.8 Generation Activity Log

Each Project registered in NC-RETS will have a Generation Activity Log associated with it. The Generation Activity Log is an electronic ledger where generation is posted prior to Certificate creation. Each time generation data is received by NC-RETS for a particular Project, the date and quantity of MWh is posted to the Generation Activity Log. Similarly, adjustments received will be posted likewise. The status of each entry in the Generation Activity Log will be noted, where the possible values are:

- **NC-RETS Accepted:** This label is used for all generation that has been reported to NC-RETS, has passed the NC-RETS feasibility test and has been logged to the Generation Activity Log, but has not yet been accepted (or disputed) by the Account Holder.

- **NC-RETS Pending:** The NC-RETS Administrator is waiting for the resolution of a situation before the Certificates can be issued. For example, if the NC-RETS Administrator is waiting to receive a Fuel Type allocation from a Multi-fuel Generation Project or other update from a Generating Unit.

- **Account Holder Accepted:** The Account Holder has accepted the posted generation, but the Certificates have not yet been issued.

- **NC-RETS Admin Accepted:** The NC-RETS Administrator has accepted the posted generation, but the Certificates have not yet been issued.

- **Account Holder Disputed:** The Account Holder has disputed the posted amount of generation.

- **NC-RETS Admin Disputed:** The NC-RETS Administrator has disputed the posted amount of generation.

- **Certificates Created:** Certificates have been created.

The status of each entry in the Generation Activity Log will be changed consistent with the information received by the NC-RETS Administrator. Certificates will be issued based on the total whole number of MWh on the Generation Activity Log that are marked "Account Holder Accepted." Only Certificates that are marked as such will contribute to Certificate creation. Any fractional MWh will be rolled forward until sufficient generation is accumulated for the creation of a Certificate. Each time an item is posted to the Generation Activity Log, the Account Holder will be notified electronically. Account Holders will have fourteen (14) calendar days to accept or dispute any new regular entries to the Generation Activity Log and fourteen (14) days to accept or dispute adjustments. If the Account Holder does not respond, the posting will be automatically accepted after the specified period and Certificates issued.

The Generation Activity Log will include, at minimum, the following entries:

(a) Account Holder's Name
(b) Activity Date
(c) NC-RETS Project ID for associated data posted
(d) Activity Description identifying Data Submitted, Fractional Data Remaining, Certificates Created, etc.
(e) Reporting Period Start
(f) Reporting Period End
(g) MWh of generation reported to NC-RETS during the current month
(h) Fuel Type
(i) Status
(j) Note (displaying Serial Numbers or data upload file names)

5.9 Multi-fuel Generation Projects

For Multi-fuel Generation Projects, Certificates will be created for the eligible Fuel Type(s) only.[1] Each Certificate issued for a Multi-fuel Generation Project will reflect only one fuel source, with the total number of Certificates issued for a Fuel Type being proportional to the overall output for that reporting period.

After each upload of production data, the Project's Account Holder will be asked to first verify the energy production data, and then input how much of the production is attributable to each Fuel Type. The Account Holder for the facility shall retain for audit supporting documentation related to the derivation of the proportion of electric output per Fuel Type for each period for which the Generating Unit is issued Certificates. Such supporting documentation is subject to audit by state regulators (including the Commission) and the Project's QRE.

5.9.1 Allocating Output for Each Fuel Source

For purposes of creating Certificates reflecting the fuel source mix of Multi-fuel Generation Projects, the proportion of Certificates attributable to each Fuel Type shall be determined consistent with the following rules:

For biomass co-fired with fossil fuels or using fossil fuels for startup or supplemental firing: In each month, the Certificates for each Fuel Type in such Multi-fuel Generation Project will be created in proportion to the ratio of the net heat content of each fuel consumed to the net heat

[1] For example, a coal-fired Generating Unit that uses biomass for co-firing can be considered a Multi-fuel-Generation Project and have biomass Certificates issued in respect of that biomass-fired generation.

content of all fuel consumed in that month, adjusted to reflect differential heat rates for different fuels, if applicable.

5.10 Energy Efficiency Data Requirements

An Electric Power Supplier that is eligible to demonstrate Portfolio Compliance via Energy Efficiency Certificates, or its Utility Compliance Aggregator, shall create a Project in NC-RETS for that purpose. The Electric Power Supplier (or its Utility Compliance Aggregator) shall use the Self-Reporting Interface to create EECs. The Electric Power Supplier or its Utility Compliance Aggregator shall retain for audit work papers demonstrating how it calculated the amount of EECs to be created. Such work papers shall detail for each customer program the estimated volume of customer participation and related energy savings, adjustments for actual operating results (participation and savings rates) and the findings of measurement and verification analyses.

6 Creation of Certificates

Certificates are issued in whole numbers only. Once a Certificate is created, no changes can be made to that Certificate.

6.1 Certificate Creation

The NC-RETS Administrator will issue one Certificate for each MWh of eligible electric energy or 3,412,000 Btu of eligible thermal energy that is generated or electric energy saved by a Project. Certificates are issued based on the number of whole MWh listed in the Generation Activity Log for a given reporting period. Each Certificate shall have a unique Serial Number. Certificate Serial Numbers shall contain codes embedded in the number. The table below identifies the Serial Number format used in NC-RETS.

TABLE 2: NC-RETS SERIAL NUMBER IDENTIFIERS

Identifier	Display Order	Data Type	Length	Range of Codes	Comments
Originating Registry	1	Alpha-numeric	3	NCRETS (WREGIS, ERCOT, GATS, MRETS, MIRECS, NEPOOL & NAR (for Certificate imports)	Used to identify originating registry (especially important for enabling import-exports with other registries)
Unit type	2	Alpha-numeric	4	REC: Renewable Energy Certificate issued for a Renewable Energy Facility or SEPA allocation EEC: Energy Efficiency Certificate issued for an energy efficiency project	Used to identify if the issuance is based on renewable energy generation, energy efficiency project
NC-RETS ID	3	Numeric	6	1-999999	NC-RETS Unique ID assigned to each Facility
State	4	Alpha-numeric	2		State Abbreviation identifying the State in which the renewable energy generation occurred. SEPA would be NA. EE or DSM would be NC

Identifier	Display Order	Data Type	Length	Range of Codes	Comments
Vintage Month	5	Numeric	2	01-12	The month in which the renewable energy and SEPA generation occurred. Not needed for EE and DSM
Vintage Year	6	Numeric	4	2008-2099	The year in which the energy efficiency or renewable energy generation occurred.
Batch Number	7	Numeric	5	Numeric value assigned to the each batch of certificates created 1 – 99,999 unique per source per vintage.	
Serial Block Start	8	Numeric	9	Numeric values assigned by NC-RETS from 1 - 999,999,999.	A number to identify the first certificate in a block of certificates.
Serial Block End	9	Numeric	9	Numeric values assigned by NC-RETS from 1 - 999,999,999.	A number to identify the last certificate in a block of certificates.

6.2 Process and Timeline for Certificate Creation

Certificates will not be issued for generation occurring prior to January 1, 2008.

Once the generation data (production data as measured by a Qualifying Meter or a Qualifying Estimate) is received by the NC-RETS Administrator and a data validity check is performed, it will post in the Account Holder's "Generation Activity Log" and NC-RETS will notify the Account Holder via email that generation has been posted. The generation posting will be marked "NC-RETS Accepted" on the Generation Activity Log. Once the generation is accepted by the Account Holder, the generation posting will be marked "Account Holder Accepted." The Certificates will issue immediately following this. If the Account Holder takes no action, Certificates will issue in 14 days.

The Account Holder must notify the NC-RETS Administrator if it believes the generation data amount recorded on the Generation Activity Log is inaccurate for any reason. The Account Holder may register a dispute any time after the generation is posted and will have 14 calendar days to do so. While the generation posting dispute is being resolved, the generation posting will be marked "Account Holder Disputed." If the Account Holder does not register a dispute with the NC-RETS Administrator, the Certificates will be created in 14 days.

For Multi-fuel Generation Projects, RECs will not issue until the Account Holder both accepts the generation data and supplies supporting fuel allocation data, as specified in Section 5.9. The Account Holder must submit to NC-RETS the proportion of energy output to be allocated to each Fuel Type. The Account Holder provides the Fuel Type allocation via the Generation Data Review screen located in the Account Holder's Asset Management Module. The fuel allocation information will remain available in NC-RETS for audit purposes. Account Holders must retain for audit the work papers demonstrating how they determined the fuel allocation for each reporting period.

6.3 Certificate Creation for Accumulated Generation

Generation data from Renewable Energy Facilities that have a Nameplate Capacity of 10 kW or less that self-report their output need not be reported monthly and may be accumulated over several months prior to submittal to NC-RETS for Certificate issuance. However, NC-RETS will require the owner to self-report the data in time-increments that do not exceed 31 days. The vintage on the issued Certificate(s) will be the last month and year of generation contributing to one (1) accumulated MWh.

6.4 Data Fields Carried on Each Certificate

Each Certificate carries a list of data fields. Some of these fields may not be applicable for energy efficiency projects.

TABLE 3: CERTIFICATE DATA FIELDS

DATA FIELD	COMMENTS
CERTIFICATE DATA	
Certificate Type	REC or EEC
NC-RETS ID	Unique ID assigned to each Project record in NC-RETS.
Project Type	Used to identify if the issuance is based on a Renewable Energy Facility (including SEPA), or Energy Efficiency Project (including demand side management)
Project Name	Name of Project
Certificate Vintage	Vintage of Generation (month/year for RECs; Year for EEC, including DSM)
Certificate Serial Numbers	See details above
Quantity of Certificates	Total Certificates
Meter Data From:	Year-Month-Date
Meter Data To:	Year-Month-Date
Certificate Creation Date:	Date Certificates were issued in NC-RETS
Cost-Recovery Year:	Year of Cost-Recovery
NC REPS Expiration:	Expiration of NC REPS Eligibility
Utility behind project [EEC only]	Name of Electric Power Supplier running the EE/DSM program(s)
STATIC ASSET DATA	
State or Province	State or Province facility is located in
Country	Country facility is located in
NERC Region	NERC Region facility is located in
eGrid Sub-Region	eGRID Sub-Region facility is located in
Commenced Operation Date	Date the Facility commenced operation
Fuel Type	Fuel Type abbreviation
Nameplate Capacity	Nameplate Capacity of Facility
Reporting Entity Type	QRE or Self-reporting
Reporting Entity Contact Company or Organization name	Name of QRE, if applicable
Utility to which Facility is interconnected	Utility Interconnect
Hydro Upgrade (Y/N)	Denotes whether Facility has been Upgraded
Upgrade Amount: NA	Denotes the portion, if applicable, of facility that has been upgraded and is eligible to create RECs for upgrade amt.
Re-power date (required if Re-powered Indicator = Y)	Date of re-powering

NC In-State/Out-of-State	Facilities eligible for NC and located in NC; Facilities eligible for NC and located outside of NC but with power delivered to any NC utility. If these certificates are transferred out of the utility account, they lose the NC In-State and become Out-of-State; Facilities eligible for NC and located outside of NC
ELIGIBILITY FOR VOLUNTARY PROGRAMS:	
Green-e Energy Eligible[1]	Denotes eligibility and, if applicable, certification number
LIHI Certified[2]	Denotes eligibility and, if applicable, certification number

7 Certificate Errors and Correction

7.1 Generation Data Validity Check

All generation data received by NC-RETS will undergo an automatic data validity check to ensure that erroneous and technically infeasible data is not entered into NC-RETS and used to issue Certificates. The data validity check will compare reported energy production to an engineering estimate of maximum potential production, calculated as a function of technology type, associated maximum capacity factor, Nameplate Capacity, Fuel Type and time period since the previous cumulative meter reading was entered. If data entered exceeds an estimate of technically feasible generation, the NC-RETS Administrator will be notified and the generation will be posted to the Generation Activity Log noting the status of failed feasibility. The NC-RETS Administrator will contact the Account Holder if the generation data entered is infeasible.

7.2 Certificate Errors Discovered After Certificate Issuance

Once a Certificate is created, no changes can be made to that Certificate. In the event that an error is discovered after Certificates have been issued, the NC-RETS Administrator will contact the Commission to explain the issue. The NC-RETS Administrator and the Commission will determine appropriate action, which could include Retiring Certificates that were created erroneously. (Certificate issuance errors caused by errors made in calculating the relative fuel mix for Multi-fuel Generation Projects will be handled in this manner.) The NC-RETS Administrator may "freeze" Certificates that are implicated in an issuance error until a method of addressing the error is developed. This means that the Certificates cannot be transferred to another Account Holder or Retired until the error is resolved. Certificate issuance errors and their resolution will be logged, and that log made available to the Public Staff and the Commission for audit.

8 NC-RETS Compliance Requirements

Electric Power Suppliers and Utility Compliance Aggregators will make transfers to the Compliance Sub-account to mirror and support their annual Portfolio Standard compliance filing to the Commission. Certificates in this Sub-account will remain in Active status until the Compliance Sub-account has been reviewed and approved by the Commission. Once approved, the Certificates will be Retired. The Public Staff and the Commission will have access to the Sub-account details.

The process will work as follows:

1) Electric Power Suppliers will establish a Compliance Sub-account for a compliance year using the "Create New Sub-Account" link. Reference Section 2.6 for more details about how Compliance Sub-accounts function. The Electric Power Supplier or Utility Compliance Aggregator will select the relevant compliance year and compliance type (electric public utility or municipality/electric membership corporation) to determine the mandates they have to meet via the given Compliance Sub-account. Utility Compliance Aggregators will need to specify the specific Electric Power Suppliers for which they are reporting, along with the prior year retail sales for each of those Electric Power Suppliers. Utility

[1] This field is targeted for users who will use NC-RETS for voluntary program certifications.

[2] This field is targeted for users who will use NC-RETS for voluntary program certifications.

Compliance Aggregators have the option to create a Compliance Sub-account for each municipality or electric membership corporation separately if they so choose. Or, several Electric Power Suppliers (municipality/electric membership corporations only) can be grouped together for purposes of a Compliance Sub-account.

2) Electric Power Suppliers or Utility Compliance Aggregators can then proceed to transfer Certificates to the Compliance Sub-account(s).

3) From a Compliance Sub-account the Account Holder can access a Compliance Report that displays the quantity achieved and quantity still needed for specific mandates such as solar power, swine waste, and poultry waste, as well as the overall Portfolio Standard mandate, using the mandate requirement reflected in the statute for electric public utilities or municipal utilities/electric membership corporations. The report will also display the proportion of the Certificates that are in-state (including out-of-state RECs bundled with power delivered to NC) and how many are unbundled out-of-state Certificates.

4) When the Account Holder has finished their transfers for the compliance year, they will 'submit' the Compliance Sub-account for Commission review. This will lock the Certificates in place allowing for the Public Staff and Commission to perform their reviews. No changes to this Sub-account can be made by the Account Holder during this time.

5) The Commission will receive an automatic notification that a report has been submitted for their review. After their review the Commission can select to either 'approve' or 'reject' the Compliance Sub-account. Approval will result in the Certificates being Retired permanently in the Compliance Sub-account associated with the given compliance year. Rejection will reopen the Compliance Sub-account to allow the Account Holder to amend the Compliance Sub-account with the required Certificates after which they can re-submit the Sub-account for Commission review. Status of the Compliance Sub-account can be accessed via the Compliance Reports available to the Account Holder, the Public Staff and the Commission.

9 Public Reports

Public reports will be accessible to anybody via the public page on the NC-RETS website. It is expected that additional public reports will be added to meet future needs of Account Holders and Program Administrators using NC-RETS. Public reports are carefully designed to ensure the confidentiality of Account Holder data per the Terms of Use. See the Terms of Use for more information regarding confidentiality.

- **Account Holders.** This report contains a listing of all Account Holders with some limited contact information.

- **NC-RETS Projects.** This report contains a list of current and historic facilities by fuel source with owner information, updated daily as needed. It includes a link to each Project's docket within the Commission's website.

- **RECs Issued- Annual Report.** This report will have a drop-down list beginning with 2008. Data for 2010 RECs Issued will not be posted until April 1st 2011. The same will be true with all following years where the data for the previous year is not posted until April 1st. Data to be shown will be an aggregate of RECs issued by fuel type and eligibility.

- **EECs Issued- Annual Report.** This report will have a drop-down list beginning with 2008. Data for 2010 EECs Issued will not be posted until April 1st 2011. The same will be true with all following years where the data for the previous year is not posted until April 1st. Data to be shown will be an aggregate of EECs issued per utility that performed the energy savings.

- **Public Utility Compliance Report.** Provides details of each utility's Portfolio Standard compliance filed per year.

- **Imported Facilities Report.** Shows all Renewable Energy Facilities which exported Certificates into NC-RETS.

- **Bulletin Board.** Shows RECs which are posted by Account Holders as being available for purchase.

9.1 Account Holder Reports

Account Holder reports for a specific Account will only be accessible to the Account Holder, their designated agents and the NC-RETS Administrator. Account Holders, including all of the Users for an Account, can view up-to-date data in these reports at any time. Current reports include:

- **My Event Log.** This report lists all of the events that have taken place in the Account.

- **My Sub-Accounts.** This provides a list of Certificates held in the Account's Sub-accounts and allows the Account Holder to filter data by specific Active or Retirement Sub-accounts.

- **My Certificate Transfers.** This report provides a comprehensive list of Certificate transfers between Sub-accounts and other Account Holders in NC-RETS.

- **My Recurring Transfers.** This includes transfer details related to Forward Transfers only.

- **My Account Holder Registration History.** This report provides a list of all the changes to the Account Holder registration data.

- **My Project Registration History.** This report provides a list of all the Projects that have been registered in NC-RETS and includes the date of registration, the NC-RETS ID and a link to the Project registration screens.

- **My Generation Activity Log.** This report provides a log of all generation and energy efficiency data loaded into NC-RETS for all of an Account Holder's Projects. It includes both self-reported data and each file uploaded by a QRE.

- **My Generation Report:** This report shows a summary of the data loaded by vintage for each facility.

- **My Compliance Report.** This report provides North Carolina Electric Power Suppliers and Utility Compliance Aggregators the ability to view their Certificates transferred into their Compliance Sub-accounts with built-in calculations to determine if the compliance obligations are being met or not.

- **Non-NC REPS Retirement Report:** This report captures all voluntary retirement for any Account Holder retiring RECs for reasons other than the Portfolio Standard requirement.

- **Cost Recovery Report.** The Cost Recovery Report is only available to NC Electric Power Supplier Accounts. This report lists all Certificates held in the Account with a checkbox for the Account Holder to select all batches of Certificates to be reported for a cost recovery year.

- **My Invoices.** This report lists all NC-RETS invoices that have been issued to the Account Holder including the amount and payment status. The report also includes payment information.

10 Data Security

The following are a minimum set of security practice requirements for NC-RETS to ensure data integrity and confidentiality:

(a) Secured web portal interface with password protection for Static Data collection, User access and reporting.
(b) Restricted access privileges based on participant and User roles using digital certificates.
(c) Well-defined system backup and recovery processes.
(d) Secured file transfer and data upload processes using encrypted communications for all data interfaces

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Appendix A: Account Holder Registration Process

The following information will guide you through the steps necessary to create an NC-RETS Account. The NC-RETS Administrator is available to assist you throughout the registration process. Please call (888-378-4461) or email NCRETS@apxenv.com.

STEP 1 – REVIEW NC-RETS OPERATING DOCUMENTS

You should first review the NC-RETS Operating Documents including the Terms of Use, Fee Schedule and Operating Procedures. The documents are on the Documents page (under the Resources tab) on the NC-RETS website (www.NCRETS.org).

STEP 2 – ONLINE REGISTRATION

Go to www.NC-RETS.org and select the "Register for an Account" link. A pop-up window will appear with a checklist describing the steps required to register for an Account. Select the appropriate Account Type and click the "Continue Registration" button.

The available Account Types are:

- North Carolina Electric Power Supplier[1]
- General Account
- Qualified Reporting Entity
- Program Auditor

STEP 3 – ACCEPT THE TERMS OF USE

Read and agree to the NC-RETS Terms of Use (this is your next step after clicking "Continue Registration"). Acceptance of the Terms of Use must be indicated by reviewing all terms; checking each section; and lastly, agreeing to the Terms of Use by pressing the "I Agree" button.

STEP 4 – COMPLETE ACCOUNT APPLICATION

Upon accepting the Terms of Use, the next screen shows the online New Account Application Form. You will need to complete all required fields that are noted by an asterisk (*). You must designate at least one person, but may designate two, who would receive emails regarding the status of NC-RETS invoices and payments. Note: It will be possible for the public to view the Organization Contact information you provide when your Account is approved by the NC-RETS Administrator.

Upon completing the New Account Application Form and clicking "Submit," you will receive an email notification to validate/activate your registration. This activation must occur before the NC-RETS Administrator is notified of your pending Account.

STEP 5 – ACCOUNT REVIEW

[1] See Page 3 for instructions regarding inputting prior year sales data.

The NC-RETS Administrator will review the Account application. If the Account application is complete and approved, an email notification of Account approval will be sent to the designated Account Manager email address provided in the New Account Application Form. If materials are incomplete or additional information is required, the NC-RETS Administrator will notify the Account Manager. Approved Account Holders may begin using all functions of NC-RETS available to their type of Account.

STEP 6 – CREATE SUB-ACCOUNT(S) & ADDITIONAL LOGINS

Upon Account approval, default Sub-accounts are automatically created based on the privileges of your Account type. All NC Electric Service Provider Accounts, and General Accounts will receive one Active, Export and Retirement Sub-account. Additional Sub-accounts can be created and Logins added to an Account.

Appendix B: Project Registration Process

The following information will guide you through the steps necessary to register a Project in your NC-RETS General or North Carolina Electric Power Supplier Account. The NC-RETS Administrator is available to assist you throughout the registration process. Please call 888-378-4461 or email NCRETS@apxenv.com.

STEP 1 – Review NC-RETS Operating Procedures

The NC-RETS operative documents detail the requirements and definitions of different types of Projects. The documents are available on:

www.NC-RETS.org/resources/documents.

STEP 2 - Register Project

a. Log in to your Account and from the Manage Projects module, select the "Register New Project" link.
b. Fill out the information on the New Project Registration page and select "Next."
c. Continue to fill out the information on the second and third page of the New Project Registration screen and press "Submit."
d. The NC-RETS Administrator will then be notified of the New Project Registration.
e. At any time during this process you can save the form and return to complete it at a later time if you do not have all the required information.

Note: Owners of thermal projects will be required to enter their facility's maximum capacity in MW or annual energy production in MWh. To ease the process of registering a new thermal project, owners might want to calculate these conversions prior to starting the registration process.

STEP 3 - Project Review

The NC-RETS Administrator will review the New Project Registration. The NC-RETS Administrator will compare the registration information to the Commission's order approving the Project as a Renewable Energy Facility. Discrepancies regarding ownership and Project fuel(s) and size will need to be resolved before the Administrator will approve the Registration. If the New Project Registration is complete and approved, an email notification describing account approval is sent to the Account Holder. If materials are incomplete or additional information is required, the Administrator will notify the Account Manager.

STEP 4 – Certificate Issuance

Certificates can be issued whenever metering data is available and has been communicated to NC-RETS. Metering data must come from a QRE (unless the Project is a Self-Reporting Facility). The Account Holder will receive an email indicating that metering data is available for their review. The Account Holder has 14 days in which to dispute the metering data. If the Account Holder takes no action, Certificates will issue in 14 days. In addition, the Account Holder can immediately approve the data, and Certificates will issue within one day.

All energy efficiency projects (including demand side management for municipalities and electric membership corporations) are self-reporting and can submit the energy savings data once per year to issue Energy Efficiency Certificates. Such Electric Power Suppliers must retain for audit their work papers demonstrating their forecasted energy savings for each program that they operate, and the actual results of those programs, including data from measurement and verification reports filed with the Commission. A group of energy efficiency programs may be treated by an Electric Power Supplier or Utility Compliance Aggregator as one Project within NC-RETS, provided that the Electric Power Supplier or Utility Compliance Aggregator maintains thorough documentation explaining how the net savings (and resulting Energy Efficiency Certificates) were calculated.

Unless otherwise provided, each municipal utility or electric membership corporation (or their Utility Compliance Aggregator) that wants NC-RETS to issue Certificates for their Southeastern Power Administration (SEPA) allocations will need to create a Project in NC-RETS and self-report their monthly SEPA deliveries based on their invoice from SEPA.

STEP 5 – Annual Update of Renewable Energy Facility Registration

Per the Commission's rules, Renewable Energy Facilities must annually provide attestations in order to continue to earn Certificates eligible for compliance with the Portfolio Standard. Each March 1st, March 20th, April 1st and April 15th NC-RETS will send an automated notification reminder to Account Holders that have Projects assigned to them. These notifications will remind the Account Holder of the need to complete the on-line attestation form. The Account Holder will be asked to certify that the Renewable Energy Facility remains in substantial compliance with laws for protecting the environment, that the facility continues to be operated as a Renewable Energy Facility, that Certificates from the facility are not being remarketed and that the Account Holder agrees to the auditing of its books by the Public Staff and the Commission. The facility owner certifies on-line regarding these four statements and provides their name, title, company and phone number. After April 1, the Account Holder will be forced to complete the attestation in order to continue using NC-RETS. If the Account Holder has not completed the attestation by April 15, NC-RETS will notify the Commission which will consider whether to revoke the Renewable Energy Facility's registration.

Appendix C: Documentation Requirements for Multi-fuel Generation Projects

Upon registering a Multi-fuel Generation Project, the Account Holder must submit to the NC-RETS Administrator a report documenting the methodology it will use to calculate the energy production associated with each fuel used during a month. Following the NC-RETS Administrator's review and acceptance of such a report's methodology, the Account Holder may seek creation of Certificates.

Documentation of the following information used to calculate the proportion of energy output per Fuel Type generated by the Renewable Energy Facility during a billing period must be maintained by Multi-fuel Renewable Energy Facilities for 10 years or as otherwise required by Commission rule.

1. Quantities of each Fuel Type used must be documented and must be consistent with those reported to Balancing Authority(s), EPA or state air regulators, if applicable.
2. Documentation of net heat content for each Fuel Type (if applicable) must be supported by documentation.
3. Specification of a heat rate must be consistent with the heat rate reported to the Renewable Energy Facility's Balancing Authority, if applicable.

Appendix D: NC-RETS Generator Fuel Types

Fuel/Project Type (Short Description)	Fuel/Project Type(Long Description)	Renewable
BAW	Biomass - Agricultural Solid Waste	Yes
BA3	Biomass - Animal Waste - Other Animal Waste, Solid or Gas	Yes
BA2	Biomass - Animal Waste - Poultry Waste, Solid or Gas	Yes
BA1	Biomass - Animal Waste - Swine Waste, Solid or Gas	Yes
BML	Biomass - Combustible Liquids - Other	Yes
BBL	Biomass - Combustible Liquids - Spent Pulping Liquors	Yes
BMC	Biomass - Energy Crop	Yes
BLF	Biomass - Landfill Methane	Yes
BMO	Biomass - Other Biomass, including Combustible Residues	Yes
BIM	Biomass - Other Combustible Gas	Yes
BWW	Biomass - Wood Waste	Yes
CO1	Coal	No
DI1	Diesel	No
GE1	Geothermal	Yes
HYD	Hydropower - Non-SEPA	Yes
H2O	Hydropower - SEPA	Yes
JET	Jet Fuel	No
MSW	Municipal Solid Waste - Non-Renewable	No
NG1	Natural Gas	No
OC1	Ocean/Wave/Current	Yes
OIL	Oil	No
OTH	Other non-renewable fuel	No
SO1	Solar - Photovoltaic	Yes
STH	Solar - Thermal	Yes
WND	Wind	Yes

Appendix E: List of Referenced Documents

NC-RETS Terms of Use
NC-RETS Fee Schedule
North Carolina Session Laws 2007-397
Commission Rules R8-64 through 69

Appendix F: Compatible Tracking Systems

Compatible Tracking System	Can Export Certificates to NC-RETS	Can Import Certificates from NC-RETS	Website
North American Renewables Registry (NAR)	Yes	Yes	narenewables.apx.com

for those lines annually by a percentage that does not exceed the percentage increase over the prior year in the Gross Domestic Product Price Index as reported by the United States Department of Commerce, Bureau of Economic Analysis, unless otherwise authorized by the Commission. With the sole exception of ensuring the local exchange company's compliance with the preceding sentence, the Commission shall not:

a. Impose any requirements related to the terms, conditions, rates, or availability of any of the local exchange company's stand-alone basic residential lines.

b. Otherwise regulate any of the local exchange company's stand-alone basic residential lines.

(3) Except to the extent provided in subdivision (2) of this subsection, beginning on the date the local exchange company's election under this subsection becomes effective, the Commission shall not do ~~either~~ any of the following:

a. Impose any requirements related to the terms, conditions, rates, or availability of any of the local exchange company's retail services.

b. Otherwise regulate any of the local exchange company's retail services.

c. Impose any tariffing requirements on any of the local exchange company's services that were not tarriffed 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.

(4) A local exchange company's election under this subsection does not affect the obligations or rights of an incumbent local exchange carrier, as that term is defined by section 251(h) of the Federal Telecommunications Act of 1996 (Act), under sections 251 and 252 of the Act or any Federal Communications Commission regulation relating to sections 251 and 252 of the Act, nor does it affect any authority of the Commission to act in accordance with federal or State laws or regulations, including those granting authority to set rates, terms, and conditions for access to unbundled network elements and to arbitrate and enforce interconnection agreements.

(5) A local exchange company's election under this subsection does not prevent a consumer from seeking the assistance of the Public Staff of the North Carolina Utilities Commission to resolve a complaint with that local exchange company, as provided in G.S. 62-73.1.

(6) A local exchange company's election under this subsection does not affect the Commission's jurisdiction concerning the following:

a. Enforce federal requirements on the local exchange company's marketing activities. However, the Commission may not adopt, impose, or enforce other requirements on the local exchange company's marketing activities.

b. The telecommunications relay service pursuant to G.S. 62-157.

c. The Life Line or Link Up programs consistent with Federal Communications Commission rules, including, but not limited to, 47 C.F.R. § 54.403(a)(3), as amended from time to time, and relevant orders of the North Carolina Utilities Commission.

d. Universal service funding pursuant to G.S. 62-110(f1).

e. Carrier of last resort obligations pursuant to G.S. 62-110.

f. The authority delegated to it by the Federal Communications Commission to manage the numbering resources involving that local exchange company.

g. Regulatory authority over the rates, terms, and conditions of wholesale services."

SECTION 3. G.S. 62-133.5(i) reads as rewritten:

"(i) ~~To the extent applicable, a~~ A competing local provider authorized by the Commission to do business under the provisions of G.S. 62-110(f1) may also elect to have its rates, terms, and conditions for its services determined pursuant to the plan described in subsection (h) of this section. However, it is provided further that any provisions of subsection

(h) of this section requiring the provision of a specific retail service or impacting the pricing of such service, including stand-alone residence service, shall not apply to competing local providers."

SECTION 4. This act is effective when it becomes law.

In the General Assembly read three times and ratified this the 8th day of July, 2010.

s/ Walter H. Dalton
President of the Senate

s/ Joe Hackney
Speaker of the House of Representatives

s/ Beverly E. Perdue
Governor

Approved 4:11 p.m. this 2nd day of August, 2010

APPENDIX B

CERTAIN SUBSECTION (H) REQUIREMENTS AFTER SESSION LAW 2010-173

1. Docket Numbers. A Subsection (h) election filing and all future filings pursuant to that election shall be made utilizing the next sequential subdocket of the company for its current price plans. For example, the docket number for AT&T is Docket No. P-55, Sub 1013L. In the case of CLP's or a rate-of-return LEC's election of a Subsection (h) price plan, the docket number will be the next sequential docket pertaining to that company.

2. Election filing requirements. In order for a Subsection (h) election notice to be acceptable, a LEC or a CLP must file a statement under oath that it meets the following necessary conditions which are outlined in G.S. 62-133.5(h). Such LEC or CLP must submit a sworn statement (a) that its territory is "open to competition from competing local providers" within the meaning of the definition set forth in G.S. 62-133.5(h)(1)(d); (b) that it "commits to provide stand-alone basic residential lines to rural customers at rates that are less than or comparable to those rates charged to urban customers for the same service," together with providing a comprehensive list of the its current charges for stand-alone basic residential lines in each of its rural exchanges, an analysis and assessment of whether such rates are comparable, and if not, how such LEC or CLP plans to make such rates comparable; (c) that it "shall continue to offer stand-alone basic residential lines to all customers who choose to subscribe to that service"; and (d) that if it raises rates for stand-alone basic residential lines, it will only "increase rates for those lines annually by a percentage that does not exceed the percentage increase over the prior year in the Gross Domestic Product Price Index (GDP-PI)" as reported by the U.S. Department of Commerce, Bureau of Economic Analysis. Notwithstanding the above, for a CLP's notice to be acceptable, the CLP must file a statement under oath only with respect to Paragraph 2(a) above.

3. Annual stand-alone basic residential line GDP-PI statement. Any LEC that has elected to operate under a Subsection (h) price plan shall be required to provide a sworn annual statement to the Commission stating (a) the applicable GDP-PI for the prior year; (b) whether it has raised rates for stand-alone basic residential service; and (c) if so, whether such rates were raised at or below the GDP-PI; and (d) the amount such rates were raised within the various exchanges within its service area. This filing shall be made annually and will be due two weeks prior to the anniversary date of the LEC's Subsection (h) election filing so that the Public Staff will have an opportunity to review it.

4. Access charges, rates, terms, and conditions. The LEC access charges that exist in a LEC's price plan at the time of the Subsection (h) election shall continue to exist with respect to that LEC and are frozen pending a future proceeding on the subject. The access charges of a CLP electing a Subsection (h) price plan are likewise frozen.

APPENDIX C

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

Revised 08/05/10

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))

<u>FOR: QUESTIONS ON THE APPLICATION</u>

____
(NAME- PRINTED OR TYPED)

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

____
(MAILING ADDRESS - IF DIFFERENT FROM ABOVE)

____
(EMAIL ADDRESS)

____
(TELEPHONE NUMBER) (FACSIMILE NUMBER)

<u>FOR: GENERAL REGULATORY MATTERS</u>

____
(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)

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.

5. 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.

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?

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?

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.

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.

______________________________ (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.

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.

6. 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;

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.

APPENDIX D

Rule R20-1. Slamming, cramming and related abuses in the marketing of telecommunications services.

(a) No telecommunications provider shall submit, or cause to be submitted, a change order for preferred intraLATA interexchange carrier, interLATA interexchange carrier or local exchange carrier to any telecommunications company except in accordance with the procedures required by the current regulations of the Federal Communications Commission.

(b) If the Commission determines that a telecommunications provider has submitted, or caused to be submitted, a change order and cannot demonstrate that it has complied with subsection (a), the Commission shall make available to the customer the remedies authorized by the current regulations of the Federal Communications Commission, with respect to both interstate and intrastate service, and for this purpose the customer's authorized carrier may be made a party to the proceeding.

(c) (Reserved for future use.)

. . .

(e) Any telecommunications provider's telemarketing, direct mail or other forms of solicitation to change a customer's preferred local exchange carrier, intraLATA interexchange carrier, or interLATA interexchange carrier shall comply with the current regulations of the Federal Communications Commission regarding separate letters of authorization.

DOCKET NO. T-100, SUB 69

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Petition by Movin' On Movers, Inc. to Amend Rule R2-8.1	)	ORDER
Applications for Certificates of Exemption; Transfers; and	)	SCHEDULING
Notice	)	HEARING

BY THE COMMISSION: On August 29, 2008, the Commission issued its Order Amending Rule R2-8.1 and Allowing Additional Comments in Docket No. T-100, Sub 69. The Order was mailed to all companies that held a certificate of exemption on the date of issuance. Ordering Paragraph No. 2 of said Order, at page 31, requires the following:

> That, in connection with its first annual report following the issuance of this Order and the adoption of amendments to Rule R2-8.1(a) promulgated herein, each current holder of a certificate of exemption pursuant to G.S. 62-261(8) should provide the information being required by Rule R2-8.1(a) (3) e-g, as amended.

Commission Rule R2-8.1(a) (3) e-g, as amended, is as follows:

> e. That the applicant certifies that only persons possessing valid driver's licenses will operate the motor vehicles that will be used for transporting household goods;
>
> f. That the applicant or all its partners/principals submit a certified criminal history records check for the immediately preceding 10-year period; and
>
> g. That the applicant or all its partners/principals certifies that he or she (1) is a United States citizen or (2) if not a United States citizen, to submit employment authorization document(s) proving legal status to work within the United States.

On February 17, 2009, a letter, which included a blank annual report form and instructions sheet, requesting annual reports for calendar year 2008 was mailed by the Public Staff, Transportation Rates Division to all of the companies that held a certificate of exemption as of December 31, 2008. This letter again informed the companies that they must provide the information required by Rule R2-8.1(a) (3) e-g with their completed 2008 annual reports. The annual report and the information required by the amended Rule R2-8.1(a) (3) e-g were to be submitted by April 30, 2009. Subsequently, on April 14, 2009, the Commission mailed a letter to all of the companies certified as of December 31, 2008, clarifying certain aspects of the criminal history record check and employment authorization documentation required for submission under the Rule as amended.

To date, the companies listed in Appendix A, attached hereto, have failed to comply either in whole or in part with the Commission's August 29, 2008 Order.

Whereupon, the Commission is of the opinion that each company listed in Appendix A should be required to appear before the Commission at a hearing and show cause why it should not be subject to sanctions provided by statute, including monetary penalties, for failure to comply with the Commission's filing requirements. A company may be excused from attendance at this hearing if it fully complies with Rule R2-8.1(a) (3) e-g and files the required information on or before October 19, 2010.

IT IS, THEREFORE, ORDERED as follows:

1. That each company listed in Appendix A attached hereto shall appear before the Commission on Tuesday, October 26, 2010 at 9:00 a.m. in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina and show cause why it should not be subject to sanctions provided by statute, including monetary penalties, for failure to file the information required by Rule R2-8.1(a) (3) e-g as ordered by the Commission on August 29, 2008.

2. That the Public Staff of the Utilities Commission shall participate in the hearing on behalf of the using and consuming public.

3. That any company listed in Appendix A that is organized in a manner other than a sole-proprietorship/individual shall retain legal counsel, as required by Commission Rule R1-22, to represent it before the Commission in this proceeding.

4. That the Chief Clerk shall serve a copy of this Order on each company listed in Appendix A by means of United States certified mail, return receipt requested.

ISSUED BY ORDER OF THE COMMISSION.
This the 23rd day of June, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

br061910.01

Appendix A

MOTOR CARRIERS OF HOUSEHOLD GOODS DELINQUENT IN COMPLYING WITH DRIVER'S LICENSE, CRIMINAL HISTORY RECORD CHECK, AND/OR UNITED STATES CITIZENSHIP/EMPLOYMENT AUTHORIZATION DOCUMENT REQUIREMENTS

Company Name	Company Number
A & A Moving, Pitt Movers, Inc. d/b/a	T-2939
A & D Relocation, Inc.	T-4204
A & L Movers, McArthur Dale Littlejohn d/b/a	T-4369
A-1 Clean-Up & Movers, Inc.	T-4142
AAA Moving and Storage, LLC	T-4150
AAA Reed's Moving Service, Alvin Reed d/b/a	T-3951
AAA Storage Company, Inc.	T-913
ABC Moving and Storage, Inc.	T-968
ACE Movers, ACE Group Corporation Incorporated d/b/a	T-4324
Advance Moving & Storage, Inc.	T-4101
All American Moving & Storage of Fayetteville, Inc.	T-4264
All My Sons Moving and Storage, Bournias, Inc. d/b/a	T-4074
All My Sons Moving and Storage of Raleigh, SG of Raleigh, Inc. d/b/a	T-4149
All The Right Moves, Inc.	T-4222
Allen's Moving Service of Fayetteville, Inc.	T-890
Allstar Moving and Storage Co, Inc.	T-4272
All-States Moving and Storage Company	T-908
American Moving Systems & Storage, Inc.	T-4124
Anderson Moving Co., Herbert Earl Anderson d/b/a	T-4320
Andy Anderson Moving Company, Craig M. Anderson d/b/a	T-3729
Antiques Abroad, Ltd.	T-4267
Anytime Movers, John Michael Garver d/b/a	T-4238
Armstrong Transfer & Storage Co, Inc./ Armstrong Relocation Company	T-3206
Arpin, Paul, Van Lines, Inc.	T-4107
ASE Moving Services, American Star Enterprises, Inc. d/b/a	T-3245
Atlantic Moving Systems, Murray Transfer & Storage Company, Inc. d/b/a	T-4389
Ballantyne & Beyond, LLC	T-4400
Barnes & Barnes Moving, Margaret Hunsucker Barnes d/b/a	T-2869
Berger Charlotte, Inc.	T-4169
Bill Scott Trucking, William B. Scott d/b/a	T-4281
Blue Ridge Movers, Inc.	T-4359
Bright's Moving, Susan Bright Melton d/b/a	T-4302
Bulldog Moving, LLC	T-4344
Campbell's Transfer & Storage, Tommy Campbell d/b/a	T-2471
Caraway Moving, Inc.	T-4211
Carey Moving & Storage of Asheville, Inc.	T-9

GENERAL ORDERS -- TRANSPORTATION

Company Name	Company Number
Carolina Classic Transport, LLC	T-4212
Central Moving & Storage, Inc.	T-4386
Chapel Hill Moving Company, Inc.	T-4191
Charlotte Van and Storage Co., Inc.	T-931
China Grove & Landis Moving, Ecil Campbell d/b/a	T-4136
City Transfer & Storage Co.	T-416
Coastal Moving Company, Inc.	T-1643
Coleman American Moving Services, Inc.	T-4263
Covan World Wide Moving, Inc.	T-4085
Crofutt & Smith Storage Warehouse of North Carolina, Inc.	T-3803
Crown Moving & Storage, Inc.	T-1595
Custom Moving and Storage, Inc.	T-1700
D C Movers, LLC	T-4220
DeHaven's Transfer & Storage of Greensboro, Inc.	T-2244
DeHaven's Transfer & Storage of Raleigh, Inc.	T-2490
DeHaven's Transfer & Storage of Wilson, Inc.	T-3255
DeHaven's Transfer & Storage, Inc.	T-1276
Delancey Street Moving & Transportation, Delancey Street North Carolina d/b/a	T-3214
Denham Moving Services, Kiply Todd Denham d/b/a	T-4229
Duke, D.R., Moving, Inc.	T-4073
Dunmar Moving Systems, Centre Carriers Corp. t/a	T-4261
Dunnagan's Moving & Storage, James G. Dunnagan d/b/a	T-2739
Eastern Moving and Storage, Inc.	T-3372
Easy Movers, Inc.	T-4087
Excel Moving & Storage of Greensboro, Inc.	T-4217
Excel Moving and Storage, Inc.	T-4118
Exodus Works, Exodus Outreach Foundation d/b/a	T-4385
E-Z Move, Inc.	T-4192
Fayetteville Moving & Storage, Inc.	T-952
Ferguson, Gene, Moving Co., Inc.	T-4243
Fidelity Moving & Storage Co., Inc.	T-1267
First Choice Moving & Storage, Inc.	T-4167
Fleming – Shaw Transfer and Storage, Inc.	T-60
Gasperson Transfer, WNC Moving & Storage, Inc. d/b/a	T-4090
Gentle Giant Moving Company (NC), LLC	T-4321
Goldsboro Van & Storage, Inc.	T-1594
Graebel /North Carolina Movers, Inc.	T-2333
GT Moving, Inc.	T-4364
Hardy Moving & Storage, Kitchen Distributors of North Carolina, Inc. d/b/a	T-4144
Harrison's Moving & Storage Co., Inc.	T-4381
Highland Moving & Storage Co., City Transfer Fayetteville, LLC d/b/a	T-4375

Company Name	Company Number
Hilldrup Moving & Storage, Hilldrup Companies, Inc. d/b/a	T-4095
Holloway Moving and Storage, Inc.	T-4122
Home 2 Home Moving, Pickup & Delivery Co.	T-4168
Hood's Movers, Linwood Hood d/b/a	T-4343
Horne Moving Systems, Inc.	T-1651
Humphrey, Troy, Moving & Storage, Inc.	T-986
I. H. Hill Transfer and Storage, Inc.	T-876
International Moving & Storage, Inc.	T-4093
Jack Bartlett Moving Company, Jack Bartlett Moving Company, Inc. d/b/a	T-1863
Jackson Moving and Storage Company	T-855
Jeff's Express, LLC	T-4403
John's Moving & Storage, Outstanding Service Corp. d/b/a	T-4135
John's Service Company of New Bern, Inc.	T-4315
Kepley Moving and Storage, Inc.	T-1006
LaFayette Moving & Storage, Inc.	T-3997
Lawrence Transportation Systems, Inc.	T-1765
Lil John Movers, Johnnie Peele d/b/a	T-4312
Long Transfer, Inc.	T-2306
Lytle's Transfer & Storage, Inc.	T-4098
Maddox Moving Services, Frank James Maddox d/b/a	T-4384
Markethouse Moving and Storage, Inc.	T-3857
Marrins' Moving Systems, Ltd.	T-4329
Mather Brothers Moving Company, LLC	T-4227
Matthews Moving Systems, Inc.	T-2985
MBM Moving Systems, LLC	T-4396
McCollister's Transportation Systems, Inc.	T-4170
Men on the Move, Inc.	T-4230
Merchants Moving & Storage, Inc.	T-1423
Mitchell Movers, Leo Mitchell d/b/a	T-4257
Modern Moving and Storage, Inc.	T-882
Move It Now, Jabear, Inc. d/b/a	T-4296
Movemart Relocation, Inc.	T-4248
Movers at Demand, Inc.	T-4176
Movers Not Shakers, Thomas James Simpson d/b/a	T-4360
Movin' On Movers, Inc.	T-3620
Moving Company, Inc., The	T-4408
Mungro's Moving, David Mungro d/b/a	T-4226
Murphy Movers, Inc.	T-4351
Murray Transfer & Storage Company, Inc.	T-350
Muscle Movers, Inc.	T-4223
Nelson's Delivery Service, John B. Nelson d/b/a	T-3579

GENERAL ORDERS -- TRANSPORTATION

Company Name	Company Number
New Beginnings Moving & Storage, Inc.	T-4265
New Bell Storage, A & E Moving and Storage, Inc. d/b/a	T-4216
New World Van Lines, Inc.	T-4291
Nilson Van & Storage, Inc.	T-3498
North Star Movers, Igor Nesterenko d/b/a	T-4333
Old Farm Rd. Moving & Storage, Timothy Cobb Robinson d/b/a	T-4380
Omni Moving and Storage, Inc.	T-552
Owen, Randy, Moving Service, LLC	T-4377
Parks Moving & Storage, Inc.	T-4197
Patterson Storage Warehouse Company, Inc.	T-857
Paxton Van Lines of North Carolina, Inc.	T-3814
Peach Movers of North Carolina, Inc.	T-4309
Piedmont Van and Storage Co.	T-1483
Pilot Van Lines, Inc.	T-1680
Port City Transfer & Storage, LLC	T-4249
Pro Movers, LLC	T-4363
Quality Moving & Storage, Inc.	T-4225
Ray Moving & Storage, Inc.	T-4301
Redi-Care Movers, LLC	T-4303
Reliable Van & Storage, Inc.	T-1597
RM Moving & Storage, McKenzie Enterprises, LLC d/b/a	T-4218
Roller Mill Moving & Storage, James Edward Davenport, Jr. d/b/a	T-4214
Sandhills Moving & Storage Co.	T-1852
Sawyers E Z Move, Sawyer Enterprises of Pensacola, Inc. d/b/a	T-4395
Seaboard Moving & Storage, Inc.	T-1664
Shore to Shore Moving & Storage, Shore to Shore, LLC d/b/a	T-4137
Small Moves, Mark Daniel Powell d/b/a	T-4251
Smith Dray Line & Storage Co., Inc.	T-853
Smith, W.E. Moving Co., City Transfer Fayetteville, LLC d/b/a	T-4376
Smoky Mountain Moving Co., Inc.	T-4111
Smooth Movin Services, Inc.	T-4284
South End Moving Co., James Canady Haywood & Jeffrey Mark Rape d/b/a	T-4362
Southern Moving, Inc.	T-4206
State Moving and Storage, Inc.	T-1518
Steele & Vaughn Moving, Johnson TV Service Center, Inc. d/b/a	T-4228
Stevens Van Lines, Inc.	T-2453
Superior Moving Systems, Inc.	T-4146
T & J Movers, Tyrone Lamount Levan d/b/a	T-4327
Taylor's Moving Company, Orlandus Dungee Taylor d/b/a	T-4203
Terminal Storage Company, Inc.	T-1476
Thomas J.E., & Sons Moving, John E. Thomas d/b/a	T-4311

GENERAL ORDERS -- TRANSPORTATION

Company Name	Company Number
T-N-T Moving Systems, Inc.	T-4201
Trading Post, Inc., The	T-4196
Triangle Mobile Storage & Moving, LLC	T-4339
Triangle Moving Service, Inc.	T-3809
Tri-City Movers, Kelvin Plummer Kearney d/b/a	T-4407
Triple A Moving & Storage, Inc.	T-3438
TROSA Moving, Triangle Residential Options for Substance Abusers, Inc. d/b/a	T-4082
Truckin' Movers Corporation	T-4154
Tru-Pak Moving Systems, Inc.	T-1429
Turner's Moving, Inc.	T-4405
Two Men and A Truck, Soaring Eagle, Inc. d/b/a	T-4086
Two Men and A Truck of Asheville, AMS & Sons Moving Co., LLC d/b/a	T-4338
Two Men and A Truck of Durham, NC, Oliver & Finley, LLC d/b/a	T-4278
Two Men and A Truck of Eastern NC, ARRGH, LLC d/b/a	T-4368
Two Men and A Truck of Fayetteville, Green Leaf Associates, Inc. d/b/a	T-4370
Two Men and A Truck of Raleigh, SOKO, Inc. d/b/a	T-4131
Two Men and A Truck of Wilmington, T & K Moving, Inc. d/b/a	T-4132
Two Men and A Truck of Winston-Salem, MOTS, Inc. d/b/a	T-4198
Umstead Brothers, Inc.	T-1439
VIP Transport Services, Langlois Ventures, Inc. d/b/a	T-4394
Wainwright Transfer Co. of Fayetteville, Inc.	T-861
Weathers Brothers Moving and Storage Company, Inc.	T-4114
Weathers Moving & Distribution, Weathers Bros. Transfer Co., Inc. d/b/a	T-4194
Whitaker Moving & Express, Algie M. Whitaker, Jr. d/b/a	T-4177
Wile Transfer and Storage Co., Inc.	T-838
Willis Moving and Storage, Inc.	T-949
Worldwide Relocation Services, Inc.	T-4347
Yarbrough Transfer Company	T-734

DOCKET NO. E-2, SUB 976

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of

Application by Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc. for Authority to Adjust Its Electric Rates and Charges Pursuant to G.S. 62-133.2 and NCUC Rule R8-55	) ORDER APPROVING FUEL CHARGE ADJUSTMENT

HEARD: Tuesday, September 21, 2010, at 9:00 a.m. in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

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

APPEARANCES:

For Progress Energy Carolinas, Inc.:

Len S. Anthony, General Counsel, Progress Energy Carolinas, Inc., Post Office Box 1551, PEB 17A4, Raleigh, North Carolina 27602-1551

For the Using and Consuming Public:

Antoinette Wike, Chief Counsel, Public Staff, North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

Len Green, Assistant Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602-0629

For the Carolina Industrial Group for Fair Utility Rates II:

Ralph McDonald, Bailey & Dixon, L.L.P., Post Office Box 1351, Raleigh, North Carolina 27602-1357

BY THE COMMISSION: On June 4, 2010, Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc. ("PEC" or "the Company"), filed an Application and the accompanying testimony and exhibits of Bruce P. Barkley and Dewey S. Roberts II pursuant to G.S. 62-133.2 and Commission Rule R8-55 relating to fuel and fuel-related charge adjustments for electric utilities.

On June 11, 2010, the Commission issued an Order Scheduling Hearing, Establishing Discovery Guidelines, and Requiring Public Notice. PEC provided notice in newspapers of general circulation as required by the Order.

On June 7, 2010, the Carolina Industrial Group for Fair Utility Rates II ("CIGFUR II") filed a petition to intervene. On June 9, 2010, Roy Cooper, Attorney General, filed a notice of intervention; the intervention of the Attorney General is recognized pursuant to G.S. 62-20. On June 29, 2010, the Carolina Utility Customers Association, Inc. ("CUCA") filed a petition to intervene. The Commission allowed the intervention of CIGFUR II and CUCA on June 15, 2010 and July 2, 2010, respectively. The intervention of the Public Staff is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e). CUCA did not participate in the evidentiary hearing in this matter.

On August 20, 2010, PEC filed the supplemental testimony and exhibits of witness Barkley. On September 2, 2010 and September 8, 2010, the Public Staff filed requests for an extension of time to file its direct testimony and exhibits. The Commission granted both requests, on September 3, 2010 and September 8, 2010, respectively. On September 9, 2010, the Public Staff filed the affidavit of Thomas W. Farmer, Jr. and the testimony and exhibits of Kennie D. Ellis and Randy T. Edwards. On September 17, 2010, PEC filed the rebuttal testimony of Bruce P. Barkley.

The case came on for hearing as scheduled on September 21, 2010. The prefiled testimonies and exhibits of PEC witnesses Dewey S. Roberts II, Manager – Power System Operations, and Bruce P. Barkley, Manager – Fuel Forecasting and Regulatory Support, were received into evidence. The Commission admitted into evidence the testimony and exhibits of Public Staff witnesses Kennie D. Ellis, Utilities Engineer, Electric Division, and Randy T. Edwards, Staff Accountant, Accounting Division, and the Affidavit of Thomas W. Farmer, Jr., Director, Economic Research Division. No other party presented witnesses and no public witnesses appeared at the hearing. On September 28, 2010 PEC filed a late-filed exhibit showing the under-recovery of fuel costs through August 2010. On October 11, 2010 the Public Staff filed a late-filed exhibit to correct a mathematical error. After the hearing, the parties filed briefs and/or proposed orders on November 1, 2010, as allowed by the Commission.

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

FINDINGS OF FACT

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 North Carolina Utilities Commission as a public utility. PEC is lawfully before this Commission based upon its Application filed pursuant to G.S. 62-133.2 and Commission Rule R8-55.

2. The test period for purposes of this proceeding is the 12-month period ended March 31, 2010.

3. PEC's fuel and fuel-related practices and procurement costs during the test period were reasonable and prudent.

4. The performance of PEC's base load plants during the test period was reasonable and prudent.

5. All of the transmission charges associated with PEC's long-term power purchase agreements with Calpine's Broad River Energy Center generating facility, Southern Company's Rowan Plant generating facility, and American Electric Power's Rockport Unit. No. 2 generating facility, are recoverable through the fuel and fuel-related cost rider.

6. The projected fuel and fuel-related costs for the North Carolina retail jurisdiction for use in this proceeding are $1,030,754,396. This consists of $77,282,805 of non-capacity purchased power costs, $25,846,580 of qualifying facility capacity costs and renewable energy costs, and $927,625,011 of other fuel and fuel-related costs. Consistent with G.S. 62-133.2(a2), the annual increase in the aggregate amount of fuel-related expenses associated with non-capacity purchased power costs, qualifying facility capacity costs, and renewable energy costs does not exceed two percent of PEC's total North Carolina jurisdictional gross revenues for 2009.

7. The Company's North Carolina retail jurisdictional fuel and fuel-related expense under-collection for purposes of the Experience Modification Factor ("EMF") was $69,427,566, including an under-collection of $67,787,680 related to the Settlement Agreement approved in Docket No. E-2, Sub 929 (the Sub 929 Settlement Agreement). As permitted by G.S. 62-133.2(d) and Commission Rule R8-55(d)(3), PEC included in the calculation of its EMFs its under-recovered fuel cost through July 31, 2010. The under-collection also reflects allowed interest. PEC's request to recover $34,009,193 of the under-collection in this proceeding and to seek recovery of $35,418,373 in next year's proceeding is approved. However, all amounts recorded subsequent to March 31, 2010 will be subject to audit by intervenors and further review by the Commission.

8. The uniform bill adjustment methodology proposed by PEC is consistent with the Sub 929 Settlement Agreement, is just and reasonable, and should be approved for the purpose of this proceeding.

9. The provision of the Sub 929 Settlement Agreement to spread the recovery of PEC's fuel and fuel-related cost under-recovery as of July 31, 2008, over three years with interest is reasonable and should be approved for the purpose of establishing the appropriate EMFs to adopt in this proceeding.

10. Consistent with the cost allocation requirements of G.S. 62-133.2(a2)(1) and the Sub 929 Settlement Agreement, the proper composite fuel and fuel-related costs factors for this proceeding for each of PEC's rate classes, excluding gross receipts tax (GRT) and regulatory fee, are as follows: 2.957¢/kWh for the Residential class; 2.537¢/kWh for the Small General Service Class; 2.680¢/kWh for the Medium General Service class; 2.758¢/kWh for the Large General Service class; and 3.251¢/kWh for the Lighting class.

11. The appropriate EMFs established in this proceeding, excluding gross receipts tax and the regulatory fee, are as follows: (0.012)¢/kWh for the Residential class; 0.422¢/kWh for the Small General Service class; 0.199¢/kWh for the Medium General Service class; 0.087¢/kWh for the Large General Service class; and (0.032)¢/kWh for the Lighting class.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

This finding of fact is essentially informational, procedural, and jurisdictional in nature and is not controverted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

G.S. 62-133.2(c) sets out the verified, annualized information which each electric utility is required to furnish to the Commission in an annual fuel and fuel-related charge adjustment proceeding for a historical 12-month test period. In Commission Rule R8-55(b), the Commission has prescribed the 12 months ending March 31 as the test period for PEC. PEC's filing was based on the 12 months ended March 31, 2010. In its Order Adopting Final Rules issued on February 29, 2008, in Docket No. E-100, Sub 113, the Commission amended Commission Rule R8-55 to allow a utility to include its under- or over-recovery of fuel and fuel-related costs through the date that is 30 calendar days prior to the date of the hearing, and to move PEC's hearing date from the first Tuesday in August to the third Tuesday in September. The amendments also changed the deadline for filing the information required under Rule R8-55 so that the filing must be made at least 90 days prior to the hearing and changed the effective date of any rate change resulting from such a proceeding to no later than 180 days from the filing date in this proceeding, which makes any rate change resulting from the Commission's decision in this proceeding effective on or about December 1, 2010.

The test period proposed by the Company was not challenged by any party, and the Commission concludes that the test period appropriate for use in this proceeding is the twelve months ended March 31, 2010.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3, 4 & 5

The evidence for these findings can be found in PEC's Application and the monthly fuel reports on file with the Commission as well as the testimony of PEC witnesses Barkley and Roberts and the affidavit of Public Staff witness Farmer and the testimony of Public Staff witnesses Edwards and Ellis.

Commission Rule R8-52(b) requires each electric utility to file a Fuel Procurement Practices Report at least once every 10 years and each time the utility's fuel procurement practices change. PEC's updated fuel procurement practices were filed with the Commission on June 2, 2008 in Docket No. E-100, Sub 47A, and were in effect throughout the 12 months ended March 31, 2010. In addition, PEC files monthly reports of its fuel and fuel-related costs pursuant to Commission Rule R8-52(a). These reports were filed in Docket No. E-2, Sub 943, for calendar year 2009 and Docket No. E-2, Sub 971, for calendar year 2010.

ELECTRIC – ADJUSTMENT OF RATES/CHARGES

PEC witness Barkley described in detail PEC's coal and gas procurement practices. PEC relies on short-term and long-term simulation models to estimate the coal and gas requirements of its generating plants. Using this information in conjunction with plant inventory levels and supply risks, a determination is made of the coal requirements at that time. Once this determination is made, coal suppliers are contacted and asked to submit bids to meet the coal requirements. Coal contracts are awarded based on economic evaluation, supplier credit review, past performance and coal specifications. Gas contracts follow a similar process. During the test period, PEC purchased coal at an average price of $96.15 per ton and natural gas at $6.80 per mmBtu excluding fixed costs.

Witness Barkley further testified that PEC continuously evaluates the term and spot markets for fuel and purchased power in order to determine the appropriate portfolio of long-term and spot purchases that ensures a reliable supply of electricity to customers at the lowest reasonable prices. Such evaluations include daily, weekly, and monthly solicitations and subscriptions to fuel pricing services and trade publications. Witness Barkley concluded that PEC prudently operated its generation resources and purchased power during the period under review in order to minimize its costs.

Witness Barkley testified that during the review period ended March 31, 2010, coal market prices initially decreased and then returned to approximately the same level as experienced at the beginning of the period. The strengthening of prices during the second half of 2009 and continuing through the end of the review period was attributable to indicators of worldwide economic recovery and to decreasing coal production. Supply reductions were primarily based upon the weak economy and high coal inventories at US utilities that led to lower market prices.

Witness Barkley testified that, as shown on his Exhibit No. 2, the market price of coal is expected to increase during the forecasted period. Demand is expected to increase due to anticipated global economic growth, and the challenges faced by coal mining companies to maintain or expand coal supply are expected to persist. As he had discussed in prior annual fuel review proceedings, factors negatively impacting coal supply include a shortage of labor, difficult permitting requirements for new mines and increased costs associated with miner safety and environmental regulations. Witness Barkley testified that PEC projects that its cost of coal consumed during the forecasted period will closely approximate costs forecasted in PEC's 2009 fuel and fuel-related cost recovery proceeding. However, PEC expects increasing coal costs in future annual proceedings based on the demand and supply trends outlined previously. PEC also expects the market price of coal to exhibit volatility, particularly in response to revised expectations of economic recovery and to legislation impacting coal.

Witness Barkley stated that PEC continues to follow the same procurement practices that it has historically followed as outlined in Barkley Exhibit No. 1. He explained that PEC carefully monitors supplier and freight performance to ensure compliance with established contracts. PEC also continuously evaluates the market for higher and lower sulfur coals, maintaining maximum supply flexibility and the opportunity for potential cost savings. Finally, PEC continues to adhere to its disciplined strategy of procuring most of its coal under contractual arrangements of varying lengths and vintages, supplemented with market purchases as appropriate.

Witness Barkley testified that PEC evaluates its long-term and short-term coal needs to obtain a reliable supply of coal at the lowest total cost. Items considered in this evaluation include coal price, coal quality, transportation cost, operating costs such as the limestone and ammonia needed to operate pollution control devices, maintenance costs, emission allowance costs and any associated capital costs. PEC uses a wide variety of procurement options through its supplier bidding process in order to obtain the best-priced coal for its generating fleet. Witness Barkley emphasized that PEC has and will continue to pursue coals of varying qualities and geographic origins in order to obtain the most secure and cost effective supply of coal.

With regard to PEC's cost to transport the coal it consumes at its generating units, PEC witness Barkley stated that coal is generally transported by rail using either the CSX railway ("CSX") or the Norfolk & Southern railway ("NS"). PEC receives a limited amount of coal by truck at the Asheville Plant and has received foreign coal by barge at the Sutton Plant located near Wilmington. The Roxboro and Mayo Plants, PEC's largest coal plants, and the Asheville Plant are served solely by NS. The Robinson, Weatherspoon, and Sutton Plants are served solely by CSX. The Lee and Cape Fear Plants can be served by either CSX or NS. To minimize transportation costs, Witness Barkley testified that PEC negotiates the most advantageous rates reasonably possible. PEC, through a consortium of shippers, participates in proceedings before the Federal Surface Transportation Board in an attempt to lower its rail costs. Witness Barkley explained that PEC's use of water and truck transportation demonstrates its commitment to diversification of coal transportation. PEC indicated it does not expect significant changes in its transportation costs during the rate period. However, indices related to inflation and oil prices are variables which impact PEC's freight costs.

Finally, with regard to PEC's coal costs, witness Barkley testified that PEC hedges its coal costs by entering into long-term contracts at fixed prices for a significant portion of its projected coal needs. Any additional coal requirements are purchased on the spot market as needed to maintain inventories. PEC staggers contract expiration dates so that a portion of the contracts expires each year and is replaced with new contracts of corresponding duration, similar to the investing strategy known as dollar cost averaging. PEC targets a minimum of 85% of its projected needs for the current year to be under contract. The targeted percentages for coal under contract decline for succeeding years two through five. Contracts beyond five years may be pursued if appropriate terms and conditions can be established. This structure of tiered contracts provides a reasonable degree of cost stability and allows the Company to respond appropriately to market trends. PEC's coal contracts will enhance the reliability of coal supply over the forecasted period and reduce price volatility

With regard to PEC's cost of natural gas, witness Barkley testified that PEC's costs, excluding fixed costs, decreased by $2.74 (29%) from $9.54 per mmbtu during the prior test period to $6.80 per mmbtu during the current test period. Witness Barkley's Exhibit No. 2, Page 2, indicates natural gas prices have declined dramatically since the peak in the summer of 2008. This has resulted from the global recession and the continued success of production coming from unconventional domestic shale formations. PEC's forecasted cost of natural gas for the year ending November 30, 2011 is approximately 15% lower than the amount forecasted in last year's proceeding. PEC expects the market price of natural gas to continue to exhibit volatility.

Witness Barkley explained that PEC's natural gas procurement practices are very similar to its coal procurement practices. Production costing models are used to project future demands. Based on the projections, requests for proposals are made, bids received, and contracts based on monthly and daily price indices are established to cover a minimum of 85% of the projected requirement for the coming year. Declining percentages of firm needs are obtained for periods of up to four years. Long-term contracts are established and maintained for gas transportation. On a short-term basis, additional purchases on the spot market are made as needed to manage the Company's natural gas requirements.

Regarding PEC's natural gas hedging procedures, witness Barkley testified that in response to PEC's increased usage of natural gas beginning in 2005, PEC began hedging its natural gas requirements by executing fixed price contracts. He indicated that PEC also utilizes financial contracts to reduce price volatility and provide improved rate stability for customers. PEC has hedging targets of 50% to 80% of forecasted consumption for the calendar year and will execute financial hedges over a rolling 36-month period with declining percentages for periods beyond the upcoming calendar year.

Witness Barkley discussed the impact of newly discovered natural gas shale reserves in PEC's natural gas strategy. Primarily due to the development of shale gas reserves and advanced methods of horizontal drilling, North American natural gas resources have approximately doubled over the past three years resulting in an amount of natural gas that could supply current levels of consumption for more than one hundred years. Shale gas is expected to grow to more than 50% of domestic supply by 2030. Importantly, the shale formations are not located in the Gulf of Mexico and are much more secure from disruptions such as hurricanes.

Witness Barkley explained the forecasted availability of significant volumes of shale natural gas will continue to impact natural gas prices. Although volatility will continue, prices should be reduced by the continued growth in domestic supply. As a result of these developments, PEC is targeting to hedge at the lower end of its established hedging targets and is not hedging beyond a rolling 36-month period. PEC had previously targeted to hedge higher percentages and executed hedges over longer periods.

Witness Barkley explained PEC's belief that it should continue hedging a portion of its natural gas requirements. He stated that a cessation of hedging would expose customers to price risk and volatility. PEC's annual natural gas usage is expected to increase significantly from current levels and will be a larger component of PEC's overall fuel mix as approximately 2100 megawatts of new combined cycle gas generation is added at Richmond County, Wayne County and the proposed Sutton facility over the next few years. Natural gas prices continue to be volatile and can have large percentage changes day to day, even though prices have declined from historic highs. For example, witness Barkley observed that on April 29, 2010, the June 2010 NYMEX contract changed by approximately 8.5%. He concluded that PEC has prudently reduced its targeted percentage and time horizon for hedging in light of these evolving market realities.

Public Staff witness Farmer submitted an affidavit regarding his investigation of PEC's natural gas hedging procedures and activities. He concluded that PEC's natural gas hedging procedures and activities during the period under review were reasonable and prudent.

Effective August 20, 2007, North Carolina Session Law 2007-397 ("Senate Bill 3") added the recovery of certain fuel-related costs, including "ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions," hereinafter referred to as "reagents," through the fuel factor. Witness Barkley testified that PEC's procurement practices for limestone and ammonia are consistent with its coal procurement practices and include determining requirements, monitoring consumption and inventory levels, conducting formal requests for proposals, and prudently combining market purchases with long-term contracts. Reagent and transportation counterparties' performance is closely monitored. PEC's ammonia and limestone costs during the test period were $8,734,497 and $8,109,817, respectively.

Senate Bill 3 also amended G.S. 62-133.2 to allow electric utilities to recover the total delivered non-capacity costs, including all related transmission charges, of all power purchases subject to economic dispatch or economic curtailment, the capacity costs of power purchases associated with qualifying facilities subject to economic dispatch; and, except for those costs recoverable pursuant to G.S. 62-133.8(h), the total delivered costs of all purchases of power from renewable energy facilities pursuant to G.S. 62-133.8. Finally, Senate Bill 3 requires the inclusion in fuel costs of the net gains and losses resulting from sales of by-products produced in the generation process to the extent the cost of the inputs leading to the by-product are included in fuel or fuel-related costs. PEC witness Barkley explained that all such purchased power costs and by-product net gains and losses were included in test year expenses and PEC's forecasted fuel and fuel-related costs. PEC allocated these costs to its customers in the manner required by G.S. 62-133.2(a2). PEC witness Barkley testified that PEC prudently incurred all of its fuel and fuel-related costs in this proceeding, including its reagent and purchased power costs.

Witness Roberts testified that PEC prudently operated and dispatched its generation resources during the test period in order to minimize its fuel costs. He also testified that 45.02% of PEC's generation during the test period was provided by its nuclear plants. According to Barkley Exhibit No. 8, the average cost of nuclear fuel burned during the test period equaled $5.80/MWh. This cost is less than 15% of the cost of coal generation and less than 10% of the cost of natural gas generation.

Regarding power plant performance, witness Roberts testified that PEC uses two different measures to evaluate the performance of its generating facilities, the equivalent availability factor and the capacity factor. Equivalent availability factor refers to the percent of a given time a facility was available to operate at full power if needed. It describes how well a facility was operated, even in cases where the unit was used in a load following application. Capacity factor measures the generation a facility actually produces against the amount of generation that theoretically could be produced in a given time period, based on its maximum dependable capacity.

Regarding the operation of PEC's natural gas and coal fired plants, witness Roberts explained that PEC's combustion turbines averaged 92.15% equivalent availability and a 4.47% capacity factor for the twelve-month period ending March 31, 2010. These performance indicators are consistent with combustion turbine generation's intended purpose. The generation was almost always available for use, but operated minimally. PEC's intermediate combined cycle unit had an 85.30% equivalent availability and a 58.92% capacity factor for the twelve-month period ended March 31, 2010. PEC's intermediate coal-fired units had an average equivalent availability factor of 89.53% and a capacity factor of 53.62% for the twelve-month period ended March 31, 2010. Again, these performance indicators for the intermediate units are indicative of good performance and management. Witness Roberts testified that PEC's fossil base load units had an average equivalent availability of 92.97% and a capacity factor of 70.31% for the twelve-month period ended March 31, 2010. Thus, the fossil base load units were also well managed and operated.

With regard to the operation of PEC's nuclear generation plants, witness Roberts explained that for the twelve-month period ended March 31, 2010, the Company's nuclear generation system achieved a net capacity factor of 91.36%. This capacity factor includes nuclear plant refueling outages. In contrast, the North American Electric Reliability Corporation's (NERC) five-year average capacity factor for 2004-2008, appropriately weighted for size and type of each plant in PEC's nuclear system, was 89.00%. The Company's nuclear system incurred a 2.37% forced outage rate during the twelve-month period ended March 31, 2010 compared to the industry average of 3.24% for similar size nuclear generators. Witness Roberts concluded that these performance indicators reflect good nuclear performance and management for the review period.

Witness Roberts explained that Commission Rule R8-55 provides that a rebuttable presumption of prudent operation of a utility's nuclear facilities is created if it achieves a system average nuclear capacity factor during the test period that is (a) at least equal to the national average capacity factor for nuclear production facilities based on the most recent 5-year period available as reflected in the most recent NERC Equipment Availability Report, appropriately weighted for size and type of plant or (b) an average system-wide nuclear capacity factor, based upon a two-year simple average of the system-wide capacity factors actually experienced in the test year and the preceding year, that is at least equal to the national average capacity factor for nuclear production facilities based on the most recent 5-year period available as reflected in the most recent NERC Equipment Availability Report, appropriately weighted for size and type of plant. Witness Roberts testified that the Company met the standard for prudent operation as set forth in Commission Rule R8-55. Public Staff witness Ellis verified PEC's test year capacity factor calculation.

Regarding power purchases to replace PEC owned generation, witness Roberts testified that PEC is constantly reviewing the power markets for purchase opportunities. He explained that PEC purchases power when there is reliable power available that is less expensive than the marginal cost of all available resources to PEC. This review of the power markets is done on an hourly, daily, weekly, and monthly basis. Also, with regard to long-term resource planning, PEC always evaluates purchased power opportunities against self-build options.

PEC witness Roberts concluded that PEC prudently operated and dispatched its generation resources during the period April 1, 2009 through March 31, 2010 in order to minimize its fuel costs.

Public Staff witness Ellis testified that his investigation included a review of the Company's test period and projected fuel and fuel-related costs and consisted of reviewing the following: (1) the Company's application and testimony; (2) the performance of the Company's base load power plants; (3) the Company's purchased power transactions; (4) the Company's projected fuel and fuel-related costs; (5) the Company's coal, natural gas, nuclear and reagent procurement practices and contracts, and (6) the current coal, natural gas, nuclear fuel and reagents markets. He concluded that PEC had prudently operated its system during the test period and its fuel and fuel related costs were reasonable and prudent. However, he recommended that PEC should not be allowed to recover through the fuel and fuel-related costs rider a portion of the transmission service charges associated with three long-term dispatchable power purchases.

The statute and Commission Rule applicable to this issue are G.S. 62-133.2(a1)(4) and Commission Rule R8-55(a)(4). Both allow a utility to recover the following costs through the fuel and fuel-related charge adjustment clause:

> "The total delivered noncapacity related costs, including all related transmission charges, of all purchases of electric power by the electric public utility that are subject to economic dispatch or economic curtailment."

In his testimony, Public Staff witness Ellis took exception to the recovery of all monthly charges incurred by PEC to reserve firm transmission capacity under these transmission agreements, regardless of the amount of energy actually purchased by PEC using these transmission paths, as fuel and fuel-related costs under the statute. Witness Ellis testified that the Public Staff believes that these transmission charges are recoverable as fuel and fuel-related costs only if they are related to actual purchases of electric energy that are subject to economic dispatch or curtailment. Further, the Public Staff believes that only the portion of the charges related to the transmission of specific purchases of dispatchable/curtailable energy is eligible for recovery under G.S. 62-133.2(a1)(4). He also profers that under PEC's interpretation of the statute, whereby "all related transmission charges" means all charges relating to ensuring that capacity is available for the transmission of dispatchable generation and can be relied on when energy from the facilities is needed, PEC could purchase as little as one kWh of dispatchable energy from a particular source during a given test period and recover not only the small amount of noncapacity cost of that purchase but also the total amount of the charges for the availability of transmission capacity to deliver energy from that source throughout the test period. As a result, the recoverable transmission charges could be many times greater than the recoverable noncapacity-related costs of the purchases themselves. Witness Ellis stated that this scenario demonstrates that PEC's interpretation of the statute could lead to an absurd result and that costs recoverable under this provision of the statute – both noncapacity costs and transmission charges – must relate to the same purchases.

Accordingly, witness Ellis stated that the Public Staff recommends an adjustment to remove the portion of transmission charges incurred under the agreements that it contends are not related to specific purchases of energy. In order to determine a reasonable amount of transmission charges under the statute, the Public Staff calculated a pro rata adjustment to the total transmission charges that PEC seeks to recover based on the ratio of the actual use of transmission capacity for specific energy purchases to the total reserved capacity available to deliver these purchases. Based on this position and calculation, Public Staff witness Edwards testified that the Public Staff recommends a $13,336,110 decrease to PEC's NC retail fuel costs for the period April 2009 to July 2010. The Public Staff also recalculated the amount of net interest due to PEC on its under-recovery of fuel and fuel-related costs pursuant to the Sub 929 Settlement Agreement. According to witness Edwards the recalculation of net interest resulted in an additional decrease of $96,134 to the Company's proposed fuel and fuel-related costs, for a total recommended decrease of $13,432,244.

PEC rebuttal witness Barkley testified that the transmission charges at issue pertain to three firm transmission paths purchased by PEC for the purpose of bringing purchased power resources into PEC's system. The first power purchase is from Calpine Corporation's Broad River Energy Center generating facility located in Gaffney, South Carolina. This power purchase was the result of request for proposals. The firm transmission service is purchased from Duke Energy Carolinas ("Duke"). The transmission service agreement ensures that PEC is able to dispatch the Broad River Energy Center power purchase to meet PEC's retail customers' needs when it is cost effective to do so. In the absence of the firm transmission service, PEC could not rely on the Broad River purchase to meet load.

The second power purchase is from Southern Company's Rowan Plant located in Salisbury, North Carolina. Similar to the Broad River purchase, this purchase was pursuant to a request for proposals. Duke provides the transmission service which ensures that this power purchase can be dispatched to meet the needs of PEC's customers when it is cost effective to do so. In the absence of the firm transmission service, PEC could not rely on the Rowan purchase to meet load.

The third power purchase is from American Electric Power's ("AEP") Rockport Unit 2 which is a coal-fired unit located in Spencer County, Indiana. This purchase was also the result of a request for proposals. This purchase power agreement ended December 31, 2009. AEP provided the firm long-term transmission service. The transmission service agreement with AEP ensured that this power purchase could be dispatched by PEC to meet PEC's customers' needs when it was cost effective to do so. In the absence of the firm transmission service, PEC could not rely on the Rockport purchase to meet load.

Witness Barkley explained that the transmission service charges the Public Staff challenges are related solely to these long-term power purchases. He indicated that these transmission service charges were included in the economic analyses upon which PEC relied in selecting these resources over other possible purchases or self-build options. These charges would not exist absent the Rowan, AEP and Broad River power purchases. These power purchases exist all year long, not just when PEC actually dispatches the units associated with the purchases. Finally, PEC witness Barkley testified that all three power purchases were included in PEC's 2009 integrated resource plan as firm capacity. He emphasized that these power purchase resources would not qualify for inclusion as system resources if firm transmission service over which to bring the power purchase into PEC's system was not available. Absent a firm transmission path, PEC would not be able to depend upon these power purchases during peak periods. Witness Barkley noted that the Public Staff testified that it was prudent for PEC to engage in these three power purchases, that these power purchases were dispatchable, that the transmission charges in question relate to these power purchases and that it was necessary and appropriate for PEC to purchase firm long-term transmission service for each of these power purchases.

PEC witness Barkley also testified that since the passage of Senate Bill 3 in 2007 (which was the legislation that amended G.S. 62-133.2 to include this language), PEC has interpreted this new section of the fuel and fuel-related costs statute to allow a utility to recover through the fuel and fuel-related cost clause all of the non-capacity related costs of power purchases that are dispatchable and all of the transmission costs associated with the power purchase. He noted that the statute and Rule do not say that only a pro rata portion of the transmission service costs associated with a power purchase is recoverable based upon how often the dispatchable power purchase is dispatched. The Public Staff acknowledged on cross-examination that PEC has been allowed to recover all such transmission costs through the fuel and fuel-related costs rider since the statute was amended in 2007.

Regarding PEC's actual use of these firm transmission services, witness Barkley testified that PEC dispatched the Broad River power purchase during all sixteen of the months in question and the Rowan power purchase for all seven months after the contract became effective January 1, 2010. PEC dispatched the Rockport power purchase during eight months of the nine-month period from April 2009 through the expiration of the contract on December 31, 2009. Witness Barkley explained that Rockport was not available during the month of October 2009 due to a scheduled maintenance outage. In total, more than 2.6 million MWhs were provided by these power purchases during the period from April 2009 through July 2010.

Witness Barkley testified that treating fixed transmission service as usage based is inconsistent with how transmission service is actually bought and utilized, and with the intent of the General Assembly as manifested in the language of the relevant portion of the statute. He noted that the General Assembly established only two requirements for the recovery of all such transmission charges. They are: 1) that the transmission charge relates to a power purchase; and 2) the power purchase must be subject to economic dispatch or economic curtailment. He opined that if the General Assembly had intended to eliminate certain transmission costs from recoverability through the fuel and fuel-related clause, it would have chosen a phrase more prescriptive than "including all related transmission charges". Finally, witness Barkley explained, and Public Staff witness Ellis agreed on cross-examination, that the General Assembly clearly expressed an intent to encourage utilities to purchase power rather than self-build generation by making the amendments to G.S. 62-133.2 through Senate Bill 3 that allow utilities to recover purchased power costs through the fuel and fuel-related costs rider. Witness Barkley concluded that the Public Staff's recommendation would remove a portion of the incentive the General Assembly created to encourage utilities to make power purchases when economic to do so.

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In its proposed order, PEC states that this issue is one of statutory construction. PEC states that the Commission has noted on several occasions that in construing a statute the courts have held that in North Carolina that "statutory interpretation properly begins with an examination of the plain words of the statute. If the language of the statute is clear and is not ambiguous, we must conclude that the legislature intended the statute to be implemented according to the plain meaning of its terms." Three Guys Real Estate v. Harnett County, 345 N.C. 468, 472, 480 S.E.2d 681, 683 (1997). The Commission further explained that "it is fundamental that "the plain meaning of the statute.... control its applicability." Univ. of N.C. at Chapel Hill v. Feinstein, 161 N.C. App. 700, 704, 590 S.E.2d 401, 403 (2003), disc. review denied, 358 N.C. 380, 598 S.E.2d 380 (2004). Thus, the statute "must be given effect and its clear meaning may not be evaded by an administrative body or a court under the guise of construction." State ex rel. Utilities Commission v. Edmisten, 291 N.C. 451, 465, 232 S.E.2d 184, 192 (1977). In construing statutes, courts normally adopt an interpretation which will avoid absurd, bizarre consequences, the presumption being that the legislature acted in accordance with reason and common sense and did not intend untoward results. State ex rel. Com'r of Insurance v. N.C. Automobile Rate Offices, 294 N.C. 60, 68, 241 S.E.2d 324, 329 (1978). Thus, PEC submits it is the plain language of the statute and the intent of the General Assembly that must guide the Commission's interpretation.

Applying these basic principles of statutory construction, PEC believes that its position is the more reasonable and correct interpretation. PEC argues that the plain language of G.S. 62-133.2(a1)(4) states that all of the transmission service charges associated with a dispatchable power purchase are recoverable through the fuel and fuel-related cost clause. The statute does not say that transmission service charges related to a dispatchable power purchase are only recoverable when the purchased power resource is dispatched. The evidence of record clearly indicates that there are three dispatchable power purchases. The record clearly indicates to PEC that the transmission charges in question relate to these power purchases. Once these facts are established, PEC contends that the statute's requirements for recovery of transmission charges are met.

Importantly, PEC believes that its interpretation is consistent with the General Assembly's policy of encouraging power purchases. Though context is not dispositive of statutory construction, PEC states that it is informative when discerning the meaning of any statute in light of the likely legislative intent. PEC contends that the rich and continuing context from which Senate Bill 3 arose is clearly one of a governmental determination that the electric utilities in this State should both diversify and become more efficient in their generation portfolios. Specifically relevant to this dispute, PEC argues that the General Assembly expressed a preference for power purchases over self-generation when doing so is more economic and reliability is comparable. To effectuate this goal, Senate Bill 3 added three new categories of purchased power costs a utility is entitled to recover through the fuel and fuel-related costs rider. According to PEC, the Public Staff agreed that these amendments demonstrate the General Assembly's intent to incent utilities to purchase power when doing so is more cost effective than self-generation.

PEC also submits that it is important to note that the context and concerns that gave rise to Senate Bill 3 persist. Governments, the Commission, the electric industry and customers remain challenged by difficult choices concerning portfolio diversification and construction choices and costs---the imperative to maximize the efficiency of the electric power generation, delivery and consumption system has certainly not diminished. In fact, conversation continues regarding inclusion of a greater mix to the generation portfolio, and of requirements of more efficiency throughout the system. Thus, PEC believes that it is relevant and significant that PEC's actions in securing the power purchases were specifically compliant with the statutory mandate to purchase when it is cost effective to do so. Firm transmission service is a necessary and inextricable component of access to dispatchable (firm) power. The underlying determination of and analytical support for entering into these power purchases relied on inclusion of these transmission charges, priced and purchased as they are in the "real world" of transmission negotiations. PEC opines that the expenditures were reasonable, the cost analyses are not disputed, and the General Assembly's intent is effectuated by PEC's action. Moreover, there is a plain reading of the statute that harmonizes that legislative intent both with the industry practices around access to transmission as a necessary component of dispatchable purchased power and with PEC's practices and conduct in this case. To interpret these amendments in a manner that limits the purchased power costs recoverable through the fuel and fuel-related costs rider would remove a portion of this incentive, would be inconsistent with the General Assembly's intent and language, and would undercut the continuing pressure for increased operational efficiencies. Therefore, PEC believes that all of the transmission charges associated with the three long term power purchases are recoverable through the fuel and fuel-related costs rider.

In its brief, the Public Staff acknowledges the value of long-term agreements for dispatchable purchased power as a resource for meeting PEC's generation needs. The Public Staff also acknowledges the prudence of securing firm transmission capacity for the purpose of delivering energy purchased under these agreements. Moreover, the Public Staff does not question the inclusion of capacity related transmission costs with the total delivered noncapacity costs of power purchases as fuel and fuel-related costs pursuant to G.S. 62-133.2(a1)(4). The Public Staff states that its sole reason for recommending an adjustment to the Company's purchased power costs in this proceeding is its belief that only the portion of the charges related to the actual transmission of dispatchable/curtailable energy is eligible for recovery under the statute.

The Public Staff submits that it is well established that when the language of a statute is clear and unambiguous, it must be given its plain and definite meaning, without the imposition of provisions and limitations not contained therein. Union Carbide Corp. v. Offerman, 351 N.C. 310, 526 S.E.2d 167 (2000). PEC has contended that G.S. 62-133.2(a1)(4) clearly and unambiguously allows the recovery of all transmission costs related to power purchases that are subject to economic dispatch or economic curtailment, regardless of the amount of energy actually dispatched. The Public Staff cannot agree. The phrase "all related transmission charges" may appear to be unambiguous when read in isolation, but the Public Staff believes that when read with the rest of the statutory language, its meaning is less than clear. Therefore, to the extent there is ambiguity, the Public Staff states that the Commission must resort to statutory construction to determine the legislative intent. See Frye Regional Medical Center, Inc. v. Hunt, 350 N.C. 39, 510 S.E. 2d 159 (1999). In this endeavor, the Public Staff opines that the Commission may read the language of the statute not only textually, but contextually, and may consider both earlier versions of G.S. 62-133.2 and the changes enacted by Senate Bill 3 in connection with the object, purpose, and language of the subdivision. In construing an ambiguous statute, earlier statutes on the subject and the history of legislation in regard thereto, including statutory changes over a period of years, may be considered in connection with the object, purpose, and language of the statute. Lithium Corp. of America, Inc. v. Town of Bessemer City, 261 N.C. 532, 135 S.E.2d 574 (1964). Indeed, the Public Staff points out that such an approach was suggested by the Company in its references to the enhancement and expansion of the amount of purchased power costs that are recoverable under G.S. 62-133.2 and the encouragement of economical purchases by electric public utilities.

Prior to the effective date of the amendments to G.S. 62-133.2 enacted by Senate Bill 3, the Public Staff notes that the only recoverable costs related to purchased power agreements such as those at issue here were the fuel cost component, i.e., the cost of fuel burned in the process of generating electricity. Capacity costs and noncapacity costs other than fuel were not recoverable outside a general rate case. The amendments expanded the recoverable costs to include as "fuel and fuel-related costs" all of the noncapacity costs, that is, all the costs of the power that vary with the amount of energy purchased and therefore enter into the decision to dispatch or not to dispatch. The capacity costs, which are sunk costs comparable to the costs of the utility's own generation, do not enter into the dispatch decision and are not recoverable as fuel and fuel-related costs. Thus, the Public Staff submits that its proposed interpretation is entirely consistent with the objective of encouraging economical purchases. The Public Staff acknowledges that it may be argued that under this interpretation the utility will not be encouraged to enter into long-term purchased power agreements of this kind. However, the Public Staff notes that PEC's own witness testified that the decision to enter into one of these agreements as opposed to other resource options, including self-build, is based on total costs, including transmission costs. The Public Staff believes that this is as it should be, given the Company's least cost obligations as an electric public utility under North Carolina law.

The Public Staff also argues that under PEC's interpretation of G.S. 62-133.2(a1)(4), recoverable costs may include both generation related noncapacity generation costs that vary with the amount energy purchased and transmission related capacity costs that do not vary at all. The Public Staff submits that a utility could purchase as little as 1 kilowatt-hour of dispatchable energy from a generation source during a particular test period and recover not only the small amount of noncapacity related costs of those purchases but also the total amount of the charges for available transmission capacity to deliver energy from that source throughout the test period, an amount that could be many times greater than the recoverable noncapacity related costs of the purchases themselves. In other words, the related capacity charges recoverable under the statute could far exceed the noncapacity related costs of the purchases themselves. In construing statutes, courts normally adopt an interpretation which avoids absurd or bizarre consequences, the presumption being that the legislature acted in accordance with reason and common sense and did not intend unfounded results. State ex rel. Comm'r of Insurance v. N.C. Automobile Rate Admin. Office, 294 N.C. 60, 241 S.E. 2d 324 (1978). The Public Staff, therefore, believes that the better interpretation of the statute is that "all related transmission charges" means all transmission charges that are related to "total delivered noncapacity costs," not all transmission charges that are related to "purchases of electric power," and that the General Assembly intended only to allow recovery of transmission charges related to the same purchases to which the recoverable noncapacity related costs were related.

The Public Staff submits that its interpretation of G.S. 62-133.2(a1)(4) is entirely consistent with the history and purpose of this provision and gives significance and effect to each word chosen while avoiding what appears to be an absurd result. While there are admittedly certain difficulties regarding the quantification of recoverable costs under this interpretation, the Public Staff contends that these difficulties are not so great as to indicate that the General Assembly intended to allow the result that could occur under PEC's reading of the statute.

For the foregoing reasons, the Public Staff requests that the Commission conclude that G.S. 62-133.2(a1)(4) allows the recovery of only the portion of transmission charges that are related to specific purchases of energy and approve the Public Staff's proposed adjustments to PEC's fuel and fuel-related costs.

After carefully considering the evidence in the record as well as the legal arguments of PEC and the Public Staff concerning the proper interpretation of G.S. 62-133.2(a1)(4), the Commission finds and concludes that all of the transmission charges at issue in this proceeding are recoverable as fuel and fuel-related costs. In reaching such a decision, the Commission agrees with PEC's interpretation of G.S. 62-133.2(a1)(4) that there are essentially two statutory requirements for the recovery of all transmission charges as fuel and fuel-related costs. First, such transmission charges must be related to purchases of electric power made by the utility. Second, the purchase of power to which all such transmission charges relate must be subject to economic dispatch or economic curtailment. However, as noted by the Public Staff, such an interpretation should not produce an absurd result.

Turning to the evidence in the record in this proceeding, the Commission believes that the evidence demonstrates that all transmission charges at issue were prudently and necessarily incurred by PEC and related to purchases of power made by PEC during the test year. Further, the uncontroverted evidence shows that the power purchases were subject to economic dispatch or economic curtailment. While the Public Staff contends that all of the transmission charges do not directly relate to specific energy purchases and adjusts the transmission charges based on the fact that the transmission paths were not used during all hours of the test year, all evidence indicates that the transmission charges were related to power purchases made by PEC and were incurred for that sole purpose. With respect to the Public Staff's scenario attempting to demonstrate how PEC's interpretation of G.S. 62-133.2(a1)(4) would or could lead to an absurd result, the Commission notes that such a scenario is simply not presented in this proceeding and no such absurdity exists.

Finally, the Commission notes that this is a case of first impression with respect to the transmission issue presented herein. The Commission has interpreted G.S. 62-133.2(a1)(4) after carefully considering the arguments described above and has applied its interpretation to the facts and circumstances contained in the record in this particular proceeding. Should this issue arise in a future proceeding, the Commission will decide such an issue based on the evidence in the record in that proceeding.

Thus, the Commission finds and concludes that PEC's fuel and fuel-related costs and power purchasing practices and costs and the operation of PEC's base load plants were reasonable and prudent during the test period. Based upon the fuel procurement practices report, the evidence in the record and the absence of any evidence to the contrary, the Commission concludes that these practices were reasonable and prudent during the test period.

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

The evidence for these findings of fact is contained in the testimony and exhibits of PEC witness Barkley and the testimony and exhibits of Public Staff witnesses Edwards and Ellis.

Witness Barkley testified that Barkley Exhibit No. 5A provided forecasted fuel costs for the year ending November 30, 2011, and the proposed rate design to recover the cost of fuel and fuel-related costs as mandated by G.S. 62.133.2(a2). This exhibit showed total system fuel costs of $1,548,910,781 consisting of non-capacity related purchased power costs subject to economic dispatch or economic curtailment of $116,836,168, costs of capacity associated with qualifying cogeneration and small power production that are subject to economic dispatch, and the fuel and fuel-related costs of renewables as defined by G.S. 62-133.8 of $37,695,437 and other fuel and fuel-related costs of $1,394,379,176. The nuclear capacity factor included in these projections is 93.77%. PEC allocated non-capacity related purchased power costs subject to economic dispatch or economic curtailment based upon energy usage for the calendar year 2009. Costs of capacity associated with qualifying cogeneration and small power production that are subject to economic dispatch and the fuel and fuel-related cost of renewables as defined by G.S. 62.133.8 were allocated based upon peak demand. The peak demand utilized by PEC is the one hour coincident peak experienced during 2009 which occurred on August 10, 2009, from 3:00 pm to 4:00 pm. The amount of fuel and fuel-related costs allocated to the NC retail jurisdiction was presented on Barkley Exhibit No. 5B. As shown on Barkley Exhibit No. 5B, other fuel and fuel-related costs were allocated to the NC retail jurisdiction based upon forecasted sales. The amount allocated to the NC retail jurisdiction was $1,030,754,396 and included non-capacity purchased power costs, qualifying cogeneration capacity and renewable energy costs and other fuel and fuel-related costs of $77,282,805, $25,846,580 and $927,625,011, respectively. No other parties objected to or otherwise challenged PEC's forecasted fuel and fuel-related costs for the rate period.

G.S. 62-133.2(d) provides in part as follows:

> The Commission shall incorporate in its cost of fuel and fuel-related costs determination under this subsection the experienced over-recovery or under-recovery of reasonable costs of fuel and fuel-related costs prudently incurred during the test period . . . in fixing an increment or decrement rider. Upon request of the electric public utility, the Commission shall also incorporate in this determination the experienced over-recovery or under-recovery of costs of fuel and fuel-related costs through the date that is 30 calendar days prior to the date of the hearing, provided that the reasonableness and prudence of these costs shall be subject to review in the utility's next annual hearing pursuant to this section. The Commission shall use deferral accounting, and consecutive test periods, in complying with this subsection, and the over-recovery or under-recovery portion of the increment or decrement shall be reflected in rates for 12 months, notwithstanding any changes in the base fuel cost in a general rate case.

In PEC witness Barkley's revised direct testimony he stated that for service rendered through July 2010, PEC experienced a fuel revenue under-recovery of $69,427,566 in its North Carolina retail jurisdiction as shown on line 21 of Revised Barkley Exhibit No. 6. This represents an increase of $35,418,373 which is solely due to the use of actual costs rather than estimates for the period May 2010 through July 2010. The cause of the difference is primarily a longer than projected outage at the Robinson 2 nuclear plant and very hot weather experienced during May, June and July.

In PEC's requested under-recovery, witness Barkley included $67,787,680, which is one-third of the deferred account balance at July 31, 2008. A three-year collection of this amount was included in the Settlement Agreement filed in Sub 929. Witness Barkley also included an interest amount of $1,338,151 calculated pursuant to the Sub 929 Settlement.

Witness Barkley stated that PEC was not seeking to revise the proposed billing factors in this proceeding because PEC's industrial customers have relied upon the initially proposed factors for their budgeting purposes and the fuel cost collections generated by existing and proposed billing factors during the twelve months ending July 31, 2011 may offset the impact of the true-up. He stated that PEC plans to seek collection of this amount in its 2011 fuel and fuel-related adjustment proceeding.

Public Staff witness Edwards testified in his affidavit that the Public Staff investigated PEC's under-recovery. According to witness Edwards, the Public Staff's investigation of PEC's proposed EMF rider included procedures intended to evaluate whether PEC properly determined its per book fuel and fuel-related costs, and fuel and fuel-related revenues, during the test period. These procedures included review of the Company's filing, prior Commission Orders, the Monthly Fuel Reports filed by the Company with the Commission, and other Company data provided to the Public Staff. Additionally, the procedures included review of certain specific types of expenditures impacting the company's test year fuel and fuel-related costs, including nuclear fuel disposal costs and payments to non-utility generators. Also, the Public Staff's procedures included review of source documentation of fuel and fuel-related costs for certain selected Company generation resources. Performing the Public Staff's investigation required the review of numerous responses to written and verbal data requests. The Public Staff generally limited its investigation to costs incurred during the test year, in accordance with G.S. 62-133.2(d) and Commission Rule R8-55. Witness Edwards testified that the Public Staff will review PEC's fuel and fuel-related costs incurred from April 2010 through July 2010 in PEC's next annual fuel proceeding.

Witness Edwards concurred with PEC's fuel and fuel-related costs calculations with the exception of the recommended disallowance of $13, 336,110 of purchased power transmission charges discussed in the Evidence and Conclusions for Finding of Facts 4-6 above and reduction of related interest costs of $96,134. Witness Edwards explained that revised rates based upon PEC's actual fuel and fuel-related costs through July, 2010, adjusted to reflect the Public Staff's proposed disallowance, are higher than those being proposed by PEC in this case given that PEC is not seeking to revise its proposed rates to reflect actual rather than estimated costs for the period May-July of 2010. Therefore, the Public Staff recommended approval of PEC's proposed rates.

PEC witness Barkley testified that he had determined that PEC's annual increase in the aggregate amount of the costs identified in subdivisions (4), (5), and (6) of G.S. 62-133.2(al) does not exceed 2% of its North Carolina retail gross revenues for 2009, as required by G.S. 62-133.2(a2).

No other party offered any evidence regarding PEC's under-recovered fuel and fuel-related costs or the Company's forecasted costs for the projected billing period from December 1, 2010, through November 30, 2011. Given that PEC and the Public Staff agree upon the proposed rates, the Commission approves their implementation.

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

The evidence for these findings of fact is contained in the testimony and exhibits of PEC witness Barkley and the testimony and exhibits of Public Staff witnesses Edwards and Ellis.

In PEC's Application and as explained in PEC witness Barkley's testimony, PEC is proposing to recover fuel and fuel-related costs in a manner that will provide to each rate class the same percentage decrease in their average monthly bill. Witness Barkley testified that the Settlement Agreement approved in part by the Commission in Docket No. E-2, Sub 929, required a uniform increase percentage for all rate classes. Specifically, Paragraph One of the Sub 929 Settlement Agreement stated: "In PEC's 2008, 2009 and 2010 fuel and fuel-related cost recovery proceedings, PEC shall propose and all parties shall support the recovery of PEC's fuel and fuel-related costs using a uniform percent increase per average monthly bill per rate class methodology such that each rate class will, on average, experience the same average monthly percent bill increase based upon current rates and charges." PEC proposes that the decrease in this proceeding be handled in a manner consistent with the Settlement Agreement.

Prior to the enactment of Session Law 2007-397, G.S. 62-133.2(a) required the Commission to apply a "uniform increment or decrement" to electric rates for the recovery of fuel costs, i.e., all customers in all classes paid the same fuel rider per-kWh consumed. Section 5 of Session Law 2007-397 removed the word "uniform" from the statute. In the present case, PEC proposes to develop individual factors for each rate class such that each class will experience the same percentage decrease in its average monthly bill. The overall average monthly bill decrease proposed by PEC was -5.28% and was calculated by dividing the level of decrease shown on Barkley Exhibit No. 5B by the annualized and normalized revenues as shown on Barkley Exhibit No. 5C. The rate design being proposed by PEC is consistent with the Sub 929 Settlement Agreement.

Based upon PEC witness Barkley's supplemental testimony, the fuel and fuel-related factors proposed are:

Rate Class	Proposed Adjustment	Proposed Factors	Proposed Adjustment with GRT and Reg. Fee
Residential	1.677¢/kWh	2.957¢/kWh	1.735¢/kWh
Small General Service	1.257¢/kWh	2.537¢/kWh	1.300¢/kWh
Medium General Service	1.400¢/kWh	2.680¢/kWh	1.448¢/kWh

Large General Service	1.478¢/kWh	2.758¢/kWh	1.529¢/kWh
Lighting	1.971¢/kWh	3.251¢/kWh	2.039¢/kWh

The proposed factors above represent total billing rates per Barkley Exhibit No. 5D, exclusive of the EMF. The proposed adjustment is the difference between the proposed fuel factors and the base fuel factor of 1.280¢/kWh originally determined in Docket No. E-2, Sub 537, and as modified in Docket No. E-2, Sub 929.

PEC calculated the necessary EMFs in Barkley Revised Exhibit Nos. 6A through 6D. Witness Barkley testified that he computed EMFs based upon (1) the over-recovery of $45.2 million incurred for service rendered from August 1, 2009 through April 30, 2010; (2) the estimated under-recovery of $10.1 million for service rendered from May 1, 2010 through July 31, 2010; (3) $1,288,854 of interest accrued through July 31, 2010, pursuant to the Sub 929 Settlement Agreement; and (4) $67,787,680, or one-third of the July 31, 2008 deferred account balance as per the Sub 929 Settlement Agreement. These EMFs will remain in effect for twelve months from the effective date of the Commission's Order in this proceeding. The 36,270,199,385 kWh used to calculate the EMF increments represented test year sales to the North Carolina retail jurisdiction adjusted for customer growth and weather normalization. The proposed EMFs are (0.012)¢/kWh for the Residential class, 0.422¢/kWh for the Small General Service class, 0.199¢/kWh for the Medium General Service class, 0.087¢/kWh for the Large General Service class, and (0.032)¢/kWh for the Lighting class, excluding GRT and the regulatory fee. The EMFs including GRT and the regulatory fee are (0.012)¢/kWh for the Residential class, 0.437¢/kWh for the Small General Service class, 0.206¢/kWh for the Medium General Service class, 0.090¢/kWh for the Large General Service class, and (0.033)¢/kWh for the Lighting class.

Public Staff witness Edwards testified that the Public Staff proposed no adjustments to PEC's proposed EMF increments.

Public Staff witness Ellis explained that the total requested dollar decrease as shown on Revised Barkley Exhibit No. 5B is $170,469,937, which reflects projected fuel and fuel-related costs of $1,030,754,396 as well as under-recovered fuel and fuel-related costs of $35,067,341 which include the under-recovered fuel and fuel-related costs during the updated test period (through July 31, 2010) and the third year of the three-year phased-in recovery of $203,363,040 deferred account balance as of July 31, 2008, as provided in the Sub 929 Settlement Agreement. Witness Ellis testified that the projected decrease in fuel and fuel-related costs is largely attributable to a dramatic decrease in coal and natural gas prices during the latter part of 2008 and into 2009. He also testified in support of using the same percentage decrease per average monthly bill for each rate class that witness Barkley proposed and that the prospective and EMF components of the total fuel factors were calculated in accordance with the requirements of G S. 62-133.2.

Witness Ellis recommended approval of the following total fuel factors (the sum of the fuel and fuel-related components and EMF component, excluding GRT and the regulatory fee) consistent with the testimony of PEC witness Barkley effective for the twelve months beginning December 1, 2010:

Rate Class	Total Fuel Factor
Residential	2.945¢/kWh
Small General Service	2.959¢/kWh
Medium General Service	2.879¢/kWh
Large General Service	2.845¢/kWh
Lighting	3.219¢/kWh

No other party offered any evidence regarding PEC's under-recovered fuel and fuel-related costs or forecasted fuel and fuel-related costs for the rate period. Nor did any other party present any evidence regarding PEC's proposed EMFs. No other party presented any evidence regarding the proper rate design for the recovery of these costs. Therefore, the Commission finds and concludes that the rates proposed by PEC and recommended by the Public Staff are just and reasonable and should be approved for the purposes of this proceeding.

IT IS, THEREFORE, ORDERED as follows:

1. That, effective for service rendered on and after December 1, 2010, PEC shall adjust the 1.280¢/kWh base fuel and fuel-related cost factor in its North Carolina retail rates approved in Docket No. E-2, Sub 537, and adjusted in Docket No. E-2, Sub 949, by an amount equal to 1.677¢/kWh for the Residential class, 1.257¢/kWh for the Small General Service class, 1.400¢/kWh for the Medium General Service class, 1.478¢/kWh for the Large General Service class, and 1.971¢/kWh for the Lighting class (excluding GRT and the regulatory fee), and, further, that PEC shall adjust the resultant approved fuel and fuel-related cost factors by increments of (0.012)¢/kWh for the Residential class, 0.422¢/kWh for the Small General Service class, 0.199¢/kWh for the Medium General Service class, 0.087¢/kWh for the Large General Service class, and (0.032)¢/kWh for the Lighting class (excluding GRT and regulatory fee). The EMF increments are to remain in effect for service rendered through November 30, 2011;

2. That PEC shall file appropriate rate schedules and riders with the Commission in order to implement these approved rate adjustments no later than 10 days from the date of this Order; and

3. 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 974, 976, and 977, and the Company shall file such proposed notice for Commission approval as soon as practicable.

ISSUED BY ORDER OF THE COMMISSION.
This the 17th day of November, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

mr111210.01

DOCKET NO. E-7, SUB 934

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Duke Energy Carolinas, LLC Pursuant to G.S. 62-133.2 and NCUC Rule R8-55 Relating to Fuel and Fuel-Related Costs Adjustment for Electric Utilities - 2010	))))	ORDER APPROVING FUEL CHARGE ADJUSTMENT

HEARD: Wednesday, June 2, 2010, at 9:00 a.m., in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

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

APPEARANCES:

For Duke Energy Carolinas, LLC:

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

and

Brian L. Franklin, Assistant General Counsel, Duke Energy Corporation, EC03T/Post Office Box 1006, Charlotte, North Carolina 28201-1006

For the Using and Consuming Public:

Dianna W. Downey, Staff Attorney, Public Staff, North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

Len Green, Assistant Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602-0629

For the Carolina Industrial Group for Fair Utility Rates III:

Ralph McDonald, Post Office Box 1351, Raleigh, North Carolina 27602

BY THE COMMISSION: On March 2, 2010, Duke Energy Carolinas, LLC (Duke Energy Carolinas or the Company), filed an application and accompanying testimony and exhibits pursuant to G.S. 62-133.2 and Commission Rule R8-55 relating to fuel and fuel-related charge adjustments for electric utilities.

On March 11, 2010, the Commission issued an Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice.

On March 19, 2010, Carolina Industrial Group for Fair Utility Rates III (CIGFUR III) filed a petition to intervene. The Commission allowed the intervention of CIGFUR III on March 24, 2010. On April 6, 2010, Roy Cooper, Attorney General, filed a notice of intervention. The intervention of the Attorney General is recognized pursuant to G.S. 62-20. On April 22, 2010, Carolina Utility Customers Association, Inc. (CUCA) filed a petition to intervene. The Commission allowed the intervention of CUCA on April 28, 2010. The intervention of the Public Staff is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

On May 3, 2010, Duke Energy Carolinas filed the direct testimony of David C. Culp adopting the previously filed testimony of Thomas C. Geer. On May 24, 2010, Duke Energy Carolinas filed supplemental direct testimony of Jane L. McManeus. On May 24, 2010, the Public Staff filed a notice of affidavits, the affidavit and exhibit of Kennie D. Ellis, the affidavit of Sonja R. Johnson, and the testimony and exhibits of Michael C. Maness.

On May 25, 2010, Duke Energy Carolinas filed a motion for witnesses to be excused from appearance at the hearing. On May 27, 2010, Duke Energy Carolinas filed the rebuttal testimony of Jane L. McManeus. On May 28, 2010, the Commission issued an order excusing the appearances of Company witnesses John J. Roebel, Senior Vice President, Engineering and Technical Services; David C. Culp, Nuclear Engineering Manager, Nuclear Fuel Management and Design; and Ronald A. Jones, Senior Vice President, Nuclear Operations, at the hearing.

On June 1, 2010, the Public Staff filed the supplemental testimony and exhibits of Michael C. Maness. On June 1, 2010, Duke Energy Carolinas filed affidavits of publication indicating that public notice had been provided in accordance with the Commission's procedural order.

The case came on for hearing as ordered on June 2, 2010. The prefiled testimony and exhibits of Company witnesses Roebel, Culp, and Jones were received into evidence, and Jane L. McManeus, Director, Rates, and Vincent E. Stroud, Vice President, Regulated Fuels, presented direct testimony for the Company. The Commission admitted into evidence the revised affidavits and exhibit of Public Staff witnesses Kennie D. Ellis, Utilities Engineer, Electric Division, and Sonja R. Johnson, Staff Accountant, Accounting Division; and Michael C. Maness, Assistant Director, Accounting Division, presented direct testimony for the Public Staff. No other party presented witnesses, and no public witnesses appeared at the hearing.

On June 3, 2010, the Pubic Staff filed its Late-Filed Exhibit 1; and on July 19, 2010, the Public Staff filed its Second Revised Exhibits of Public Staff witnesses Ellis and Maness, revising the Public Staff's recommendation in this proceeding consistent with the initial testimony of Public Staff witness Maness. Duke Energy Carolinas and the Public Staff filed a joint proposed order on July 19, 2010, as allowed by the Commission.

Based upon the Company's verified application, the testimony and exhibits received into evidence at the hearing, and the record as a whole, including the Public Staff's late-filed exhibits, the Commission makes the following:

FINDINGS OF FACT

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

2. The test period for purposes of this proceeding is the 12-month period ended December 31, 2009.

3. Duke Energy Carolinas' fuel and reagent procurement and power purchasing practices during the test period were reasonable and prudent.

4. The test period per book system sales are 78,030,866 MWh.

5. The test period per book system generation is 84,321,352 MWh and is categorized as follows:

Generation Type	MWh
Coal	35,791,156
Oil and Gas	119,434
Biomass/Test Fuel	3,558
Nuclear	43,129,082
Hydro	2,031,007
Net Pumped Storage Hydro	(722,375)
Purchased Power	3,902,545
Renewable Purchased Power	34,464
Catawba Interchange	(140,980)
Other Interchange	173,461
Total Generation	84,321,352

6. The nuclear capacity factor appropriate for use in this proceeding is 90.68%.

7. The adjusted test period system sales for use in this proceeding are 78,030,331 MWh.

8. The adjusted test period system generation for use in this proceeding is 84,188,163 MWh and is categorized as follows:

Generation Type	MWh
Coal	37,574,145
Oil and Gas	378,834
Biomass/Test Fuel	3,558
Nuclear	41,088,701
Hydro	1,882,000
Net Pumped Storage Hydro	(850,005)
Solar Distributed Generation	13,079
Purchased Power	4,097,851
Total Generation	84,188,163

9. Under G.S. 62-133.2(a1)(4), it is appropriate for the Company to recover noncapacity related costs of purchases of power only if they are subject to economic dispatch or economic curtailment. Therefore, the Company shall not be allowed to recover the system non-fuel energy expenses of purchases that are not subject to economic dispatch or economic curtailment in this proceeding.

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

A. The coal fuel price is $37.42/MWh.
B. The oil and gas fuel price is $144.32/MWh.
C. The appropriate ammonia, limestone, urea and dibasic acid (collectively "Reagents") expense is $30,247,000.
D. The appropriate net costs on sale of by-products are $2,559,000.
E. The total nuclear fuel price is $5.36/MWh.
F. The nuclear fuel price for Catawba generation is $5.53/MWh.
G. The purchased power fuel price is $29.30/MWh.
H. The adjusted level of fuel and fuel-related credits associated with intersystem sales is $51,612,000.

11. The adjusted total test period system fuel and fuel-related cost for use in this proceeding is $1,782,395,000.[1]

12. Consistent with the cost allocation requirements of G.S. 62-133.2(a2), the proper fuel and fuel-related cost factors are 2.2845¢/kWh for the Residential class, 2.2841¢/kWh for the General Service/Lighting class, and 2.2840¢/kWh for the Industrial class, excluding gross receipts tax and regulatory fee.[2]

13. The Company's North Carolina test period jurisdictional fuel and fuel-related expense over-collection, extended to include January 2010 through April 2010 pursuant to Commission Rule R8-55(d)(3), and net of the Fuel Over-Collection Rider (Docket E-7, Sub 909)

[1] Consistent with G.S. § 62-133.2(a2), the annual increase in the aggregate amount of fuel-related expenses associated with non-capacity purchased power costs, qualifying facility capacity costs and renewable energy costs does not exceed two percent of Duke Energy Carolinas' total North Carolina jurisdictional gross revenues for 2009.

[2] Duke Energy Carolinas proposed fuel and fuel-related costs factors excluding gross receipts tax and regulatory fee. However, it is appropriate for the rates schedules to reflect both gross receipts tax and the regulatory fee.

implemented January 1, 2010, was \$62,250,000, \$59,969,000, and \$28,917,000 for the Residential, General Service/Lighting, and Industrial classes, respectively. The pro forma North Carolina retail jurisdictional sales are 21,013,802 MWh, 21,502,109 MWh, and 11,376,803 MWh for the Residential, General Service/Lighting, and Industrial classes, respectively.

14. The Company's Experience Modification Factor (EMF) decrements by customer class are 0.2962¢/kWh for the Residential class, 0.2789¢/kWh for the General Service/Lighting class, and 0.2542¢/kWh for the Industrial class, excluding gross receipts tax and regulatory fee. The EMF interest decrements applicable to the net over-recovery are 0.0444¢/kWh, 0.0418¢/kWh, and 0.0381¢/kWh, respectively, for the Residential, General Service/Lighting, and Industrial classes, excluding gross receipts tax and regulatory fee.

15. The final total fuel and fuel-related cost factors to be billed to Duke Energy Carolinas' North Carolina retail customers during the 2010-2011 fuel clause billing period are 1.9439¢/kWh for the Residential class, 1.9634¢/kWh for the General Service/Lighting class, and 1.9917¢/kWh for the Industrial class, excluding gross receipts tax and regulatory fee. The proper Nantahala Area Customer Rider for the 2010-2011 billing period is 0.1539¢/kWh, excluding gross receipts tax and regulatory fee.

16. The base fuel and fuel-related cost factor established by the Commission in Duke Energy Carolinas' most recent general rate case (Docket No. E-7, Sub 909) includes non-fuel energy costs associated with purchases that are similar to the purchases for which non-fuel energy costs are being excluded from fuel and fuel-related costs in this proceeding. These costs should be recovered only in base rates. Therefore, the base fuel and fuel-related cost factor set in Docket No. E-7, Sub 909 should be restated to exclude non-fuel energy expenses of purchases that should not have been included, as recommended by the Public Staff. The appropriate restated base fuel and fuel-related cost factor is 2.3284¢/kWh.

17. It is reasonable to conclude that the non-fuel energy expenses of purchases that should not have been included in the base fuel factor in Duke Energy Carolinas' most recent general rate case, instead should have been included in the non-fuel portion of the Company's revenue requirement. Therefore, a non-adjustable base rate rider should be established to allow the Company to continue to recover the difference between the base fuel and fuel-related factor originally established in Docket No. E-7, Sub 909 and the restated factor established in this proceeding. The appropriate non-adjustable base rate rider is 0.0205¢/kWh.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

This finding of fact is essentially informational, procedural, and jurisdictional in nature and is not controverted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

G.S. 62-133.2(c) sets out the verified, annualized information that each electric utility is required to furnish to the Commission in an annual fuel and fuel-related charge adjustment proceeding for a historical 12-month test period. In Commission Rule R8-55(b), the Commission has prescribed the 12 months ending December 31 as the test period for Duke Energy Carolinas. The Company's filing was based on the 12 months ended December 31, 2009, except as it relates to the over-recovery where, pursuant to Commission Rule R8-55(d)(3), a 16-month period ending April 30, 2010, was used.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

Commission Rule R8-52(b) requires each electric utility to file a Fuel Procurement Practices Report at least once every 10 years and each time the utility's fuel procurement practices change. The Company's updated fuel procurement practices were filed with the Commission in Docket No. E-100, Sub 47A, in July 2004 and were in effect throughout the 12 months ending December 31, 2009. In addition, the Company files monthly reports of its fuel and fuel-related costs pursuant to Commission Rule R8-52(a). Further evidence for this finding of fact is found in the testimony of Company witnesses Stroud, Roebel, and Culp.

Duke Energy Carolinas witness Stroud described the Company's fossil fuel procurement practices. These practices include establishing appropriate inventory requirements, making regular requests for proposal (RFPs) and performing bid evaluation, balancing long-term contract and spot purchases, staggering contract expirations, pursuing contract extension options, maintaining a well-diversified coal supplier base, and actively monitoring supplier and railroad performance.

Witness Stroud testified that the Company continues to focus on the Central Appalachia region as its primary source of coal. He also testified that although Duke Energy Carolinas continues to maintain a comprehensive coal procurement strategy that has proven successful over the last several years in limiting average annual coal price increases and maintaining average coal costs at or well below those seen in the marketplace, coal markets overall – and the Central Appalachia market specifically – remain weak since Duke Energy Carolinas' 2009 fuel proceeding.

The weak market prices for coal due to the anemic economy and resulting low demand for electricity resulted in high inventories of coal at the Company's generating stations. The average delivered coal cost per ton increased from $80.36 per ton in 2008 to $89.87 per ton in 2009. The average mine price paid by Duke Energy Carolinas increased approximately 23%, from $55.49 per ton in 2008 to $68.09 per ton in 2009.

Witness Stroud testified that the increase was caused by the expiration of low-priced, long-term agreements and their replacement with higher-priced agreements executed during 2008, which drove up the average cost per ton of coal. During 2009, the Company primarily focused on renegotiating long-term contracts and selling some spot coal to ensure that coal inventories did not exceed maximum storage capacity at the stations. He testified that, although the high inventories are moderating back toward more desirable levels, the Company has more than 95% of its 2010 coal needs already under firm prices, and approximately only 20% of 2011 coal requirements remain open to market prices.

According to witness Stroud, the Company currently is engaged in negotiations with both Norfolk Southern Railway Company and CSX Transportation to develop replacement contracts for the delivery of coal. As a result, the Company is unable to predict transportation costs with a high degree of certainty until it finalizes the contracts with both companies. The future activities of the railroads and the Surface Transportation Board will continue to impact the Company's level of service and cost of rail transportation.

Company witness Culp testified as to Duke Energy Carolinas' nuclear fuel procurement practices. These practices involve computing near- and long-term consumption forecasts, establishing nuclear system inventory levels, projecting required annual fuel purchases, qualifying suppliers, requesting proposals, negotiating a portfolio of spot and long-term contracts from diverse sources of supply, assessing spot market opportunities, and monitoring deliveries against contract commitments.

Further, witness Culp testified that Duke Energy Carolinas relies extensively on long-term contracts to cover the largest portion of its forward requirements in the four industrial stages of the nuclear fuel cycle. By staggering long-term contracts over time, the Company's purchases within a given year consist of a blend of contract prices negotiated at many different periods in the markets, which has the effect of smoothing out the Company's exposure to price volatility.

Duke Energy Carolinas witness Roebel described the teams established to achieve the company's objectives in procurement of environmental reagents and managing by-products, which include providing the steam stations with the most effective total cost solution by understanding the technical capabilities of the equipment, assessing reagent input and by-product output over the long-term, assessing and understanding the various reagent and by-product markets, and looking for leverage opportunities with the reagent purchase and by-product sales contracts between stations and with the Company's Midwest operations.

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

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4-6

The evidence for these findings of fact is found in the testimony of Company witnesses McManeus, Roebel, and Jones, and the affidavit of Public Staff witness Ellis.

Company witness McManeus testified that the test period per book system sales were 78,030,866 MWh and test period per book system generation was 84,321,352 MWh. The test period per book generation is categorized as follows:

Generation Type	MWh
Coal	35,791,156
Oil and Gas	119,434
Biomass/Test Fuel	3,558
Nuclear	43,129,082
Hydro	2,031,007
Net Pumped Storage Hydro	(722,375)
Purchased Power	3,902,545
Renewable Purchased Power	34,464
Catawba Interchange	(140,980)
Other Interchange	173,461
Total Generation	84,321,352

Company witnesses Roebel and Jones testified as to the operation and performance during the test period of the Company's (1) fossil-fueled and hydroelectric generating facilities and (2) nuclear generation facilities, respectively. Witness Roebel testified that Duke Energy Carolinas operates a diverse mix of units that allow the Company to meet the continuously changing customer load pattern in a logical and cost-effective manner. He testified that during the test period, the fossil-fuel generating plants operated efficiently and reliably and that the heat rate of the coal units was 9,562 BTU/kWh. Witness Roebel testified that the hydroelectric fleet had outstanding operational performance during the test period, with a system availability factor of 92.6%. Witness Roebel further testified as to the various performance indicators that are indicative of solid performance and good operation and management of Duke Energy Carolinas' fossil and hydroelectric fleet during the test period.

Commission Rule R8-55(c)(1) provides that capacity factors for nuclear production facilities will be normalized based generally on the national average for nuclear production facilities as reflected in the most recent North American Electric Reliability Council's (NERC) Equipment Availability Report, adjusted to reflect the unique, inherent characteristics of the utility facilities and any unusual events. Witness Jones testified that the test period included five refueling outages and that during the test period, Duke Energy Carolinas achieved a system average nuclear capacity factor of 94.34%, the tenth straight year that Duke Energy Carolinas' system average nuclear capacity has been above 90%. He testified that the most recent (2004-2008) NERC five-year average nuclear capacity factor for pressurized water reactor units is 90.50%. In his revised affidavit, Public Staff witness Ellis stated that the updated NERC five-year average nuclear capacity factor for pressurized water reactors was 90.32% for all sizes and 90.43% for the weighted average of Duke Energy Carolinas' nuclear fleet. However, because the Company's proposed fuel and fuel-related costs factor for the billing period was based on the Company's projected 90.68% system nuclear capacity factor, which is greater than the NERC five-year average, there is no impact to retail customers of Duke Energy Carolinas' filed NERC five-year average. Witness Ellis used a nuclear capacity factor of 90.68% in his calculation of the Public Staff's recommended prospective fuel component. Duke witness Jones recommended a nuclear capacity factor of 90.68% for use in setting the fuel rate in this proceeding, based on the operational history of the Company's nuclear units and the number of outage days scheduled for the 2010-2011 billing period.

Public Staff witness Ellis agreed with the Company's per books system sales and generation levels of 78,030,866 MWh and 84,321,352 MWh, respectively, as well as the

Company's recommended nuclear capacity factor of 90.68%. No other party contested these amounts.

Based upon the agreement of the Company and the Public Staff as to the appropriate levels of per book system MWh generation and sales, and noting the absence of evidence presented to the contrary, the Commission concludes that the levels of per book system sales of 78,030,866 MWh and per book system generation of 84,321,352 MWh are reasonable and appropriate for use in this proceeding.

Based upon the requirements of Commission Rule R8-55(c)(1), the historical and reasonably expected performance of the Duke Energy Carolinas system, and the agreement of the Public Staff, the Commission concludes that the 90.68% nuclear capacity factor and the associated generation level of 41,088,701 MWh, excluding the Catawba Joint Owners' portion of said generation, are reasonable and appropriate for determining the appropriate fuel costs in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 7-8

The evidence for these findings of fact is found in the testimony of Company witness McManeus and the affidavit of Public Staff witness Ellis.

Witness McManeus made adjustments of 95,219 MWh and (95,755) MWh to per book system sales and generation, respectively, for adjustments relating to normalization for weather, customer growth, and line losses/Company use, based on a 90.68% normalized system nuclear capacity factor. Thus, witness McManeus calculated an adjusted system sales level of 78,030,331 MWh and an adjusted system generation level of 84,188,163 MWh.

Public Staff witness Ellis accepted witness McManeus' adjusted sales and generation levels of 78,030,331 MWh and 84,188,163 MWh, respectively. No party contested the Company's adjustments for weather normalization, customer growth, line losses/Company use, nuclear generation, or hydroelectric generation.

The Commission concludes, after finding a system nuclear capacity factor of 90.68% reasonable and appropriate in Finding of Fact No. 6, that the net adjustment to per book system generation of (536) MWh and the resulting adjusted test period system generation level of 84,188,163 MWh are both reasonable and appropriate for use in this proceeding. Total adjusted generation is categorized as follows:

Generation Type	MWh
Coal	37,574,145
Oil and Gas	378,834
Biomass/Test Fuel	3,558
Nuclear	41,088,701
Hydro	1,882,000
Net Pumped Storage Hydro	(850,005)
Solar Distributed Generation	13,079
Purchased Power	4,097,851
Total Generation	84,188,163

The Commission also finds the adjusted sales level of 78,030,331 MWh to be reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9.

The evidence for this finding of fact is found in the testimony of Duke Energy Carolinas witness McManeus, the affidavits of Public Staff witnesses Johnson and Ellis, the testimony of Public Staff witness Maness, and the revised and second revised exhibits filed by the Public Staff.

As Public Staff witness Maness testified, pursuant to G.S. 62-133.2(a) and (b), Duke Energy Carolinas is permitted to change its rates, on an annual basis, to "charge an increment or decrement as a rider to its rates for changes in the cost of fuel and fuel-related costs established in the electric public utility's previous general rate case."[1] There are two components to this rider, as further described in G.S. 62-133.2 and Commission Rule R8-55. The first is a prospective adjustment to the fuel and fuel-related cost component of base rates (the base fuel and fuel-related costs factor), designed to account for changes in the cost of fuel and fuel-related costs from that set in a utility's last general rate case. The prospective adjustment is designed to provide, in conjunction with the base fuel and fuel-related cost factor, for the recovery of fuel and fuel-related costs incurred over a future service period beginning as of a date specified in the Commission's final order in a given proceeding. The sum of the base fuel and fuel-related cost factor and the prospective adjustment can be referred to as the prospective component of the fuel and fuel-related cost factor.

The second component is the experience modification factor, or EMF, and reflects the difference between, or true-up of, the reasonable and prudently incurred cost of fuel and fuel-related costs incurred and the fuel and fuel-related revenues that were actually realized for a specified past test period. The prospective component and the EMF are both required to be made up of only the appropriate statutory categories of "fuel and fuel-related costs," as specifically defined in G.S. 62-133.2(a1).

In her revised affidavit, Public Staff witness Johnson testified that her investigation of the EMF riders proposed by the Company did not reveal any adjustments to the Company's reported test year North Carolina retail fuel and fuel-related cost over-recoveries of its proposed EMF riders for each of the customer classes and agreed with the Company's calculation of its revenue over-collection. Similarly, Public Staff witness Ellis agreed with the method in which the Company calculated its proposed fuel and fuel-related cost factor. Both witnesses Johnson and Ellis stated, however, that they agreed with Public Staff witness Maness that certain purchased power costs should be excluded from recovery under G.S. 62-133.2 because they are not subject to economic dispatch or economic curtailment.

Among the categories of costs that are recoverable under G.S. 62-133.2 are the "total delivered noncapacity related costs…of all purchases of electric power by the electric public utility, that are subject to economic dispatch or economic curtailment." Public Staff witness Maness testified that during the course of the Public Staff's investigation in this proceeding, the

[1] G.S. 62-133.2(a).

Public Staff discovered that Duke Energy Carolinas included in the determination of the prospective and EMF portions of its proposed fuel riders the non-fuel energy costs associated with certain power purchases that were not subject to dispatch (and, presumably, not curtailment) by the Company.[1] He stated, in his initial pre-filed testimony, that based on a response provided by Duke Energy Carolinas to a Public Staff data request, the total amount of non-fuel energy expenses not subject to hourly dispatch is approximately $29,572,000, on a system basis, for the test year ended December 31, 2009, and $35,286,000, on a system basis, for the 15 months ended March 31, 2010.[2] Witness Maness asserted that since power purchases not subject at all to dispatch or curtailment cannot by definition be subject to "economic dispatch or economic curtailment," as provided for in G.S. 62-133.2(a1)(4), it appears that the purchases with which these non-fuel energy costs are associated should be classified as "other purchased power" as set forth in G.S. 62-133.2(a1)(7), and, therefore, that only the fuel costs associated with such purchases, not the non-fuel energy costs, should be included in the prospective and EMF components of the fuel increment or decrement riders. Witness Maness stated that these non-fuel energy costs should not be recoverable under the fuel statute. Instead, they should be recoverable in base rates. However, witness Maness added that the fuel cost component of the purchases should continue to be recoverable through the fuel and fuel-related cost factor.

According to witness Maness, the Public Staff believes that in order for a power purchase to be "subject to economic dispatch or economic curtailment," the utility must have the ability to begin or end a purchase of electric energy (1) on relatively short notice (e.g., within one hour) and (2) for economic reasons (i.e., for the reason that either beginning or ending the purchase of energy is economically advantageous to the utility). For a purchase of energy to be economically dispatchable, witness Maness stated that the short notice criterion is particularly important, so that the utility possesses the flexibility to minimize its energy costs by taking advantage of changes in system, market, weather, or other conditions. Furthermore, for purchased energy to be subject to economic dispatch or economic curtailment, the utility must have the ability to decide for itself when a particular purchase is advantageous, and not be required to purchase the energy whenever it is available from the generator, i.e., the utility controls whether it meets its energy requirements with the purchase, an alternative purchase, or by generating the energy with its own facilities.

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[1] There are three categories of purchases at issue here: The first group includes generation and energy imbalance purchases which FERC regulations require Duke Energy Carolinas to make as a Transmission Provider. The second group includes instantaneous capacity and energy agreements or "load following" arrangements. These are contracts under which the Company agrees to make purchases whenever scheduled generation from a third party generator exceeds the load which it is serving (and agrees to make sales whenever such scheduled generation is less than the load it is serving). The third group includes purchases that the Company agrees to make as part of contracts to serve certain native load wholesale customers on a full requirements basis. In some cases, where such a full requirements wholesale customer has pre-existing power supply agreements with other generators for part of its load, the Company agrees to buy the power supplied by those other generators from the wholesale customer.

[2] Mr. Maness also testified that based on discussions with Company personnel subsequent to the provision of the data response, some portions of these purchases might have some dispatchable or curtailable elements, and that the Public Staff was continuing to work with the Company to make any necessary refinements to these amounts. On July 19, 2010, the Public Staff filed Second Revised Exhibits of Public Staff witnesses Maness and Ellis, which adjusted the Public Staff's recommended fuel and fuel-related cost riders to reflect these refinements.

Witness Maness testified that the U.S. Energy Information Administration (EIA) defines the term "dispatching" as follows:

> The operating control of an integrated electric system involving operations such as (1) the assignment of load to specific generating stations and other sources of supply to effect the most economical supply as the total or the significant area loads rise or fall (2) the control of operations and maintenance of high-voltage lines, substations, and equipment; (3) the operation of principal tie lines and switching; (4) the scheduling of energy transactions with connecting electric utilities.[1] [Emphasis added.]

Also, the National Association of Regulatory Utility Commissioners, in its IRC Staff Subcommittee Glossary, defines the terms "Dispatch" and "Dispatching" as follows:

> The control for an integrated electric system to schedule transactions with other interconnected electric utilities and assign generation to specific generating plants and other sources of supply to effect the most reliable and economical supply as the total of the significant area loads rises or falls. The activity has implications for operations and maintenance of high voltage lines, substations and equipment, including administration of safety procedures.[2]

In short, witness Maness testified, purchased power that is subject to "economic dispatch" is power that the utility chooses to purchase when needed and not simply whenever available from the generator; the utility has control.

Although Company witness McManeus did not agree with the "hourly" component of the Public Staff's definition of "subject to economic dispatch or economic curtailment," she otherwise agreed with the definitions of dispatch presented by Public Staff witness Maness. She also agreed that certain purchases included by the Company under G.S. 62-133.2(a1)(4) do not meet the definition of "subject to economic dispatch or economic curtailment" as defined by the Public Staff. Witness McManeus testified that the purchases for which the Public Staff has taken issue, including those certain non-fuel energy costs that are incorrectly classified as fuel-related costs, would not meet the Public Staff's criterion that the utility possess the flexibility to begin or end the purchase on relatively short notice (*e.g.*, within one hour). She testified that the Company's underlying premise for inclusion of these costs as "fuel-related" is based on economic reasons.

Company witness McManeus stated that the difference between the Company's application of the decision criteria and the Public Staff's application is related to timing. According to witness McManeus, the Public Staff's definition requires that the decision always be made in the short-term context; however, she testified that a determination of economic benefits is not always made in this manner. As a result, the Company believes that the fact that

[1] http://www.eia.doe.gov/glossary/glossary_d.htm

[2] http://www.naruc.org/Publications/Glossary_International.pdf

the time of the decision is not always on an hourly basis should not preclude the recognition of the economic value of the decision. Company witness McManeus stated that the revision to the statute to allow additional non-capacity costs to be recoverable as a fuel-related cost suggested to her that there was an intent to provide for more timely cost recovery of non-capacity purchase power costs when the purchases provide an economic benefit to customers. Witness McManeus testified that utilities routinely made economic purchases of power prior to the enactment of Senate Bill 3. However, only the fuel cost component of purchased power was recoverable through the fuel clause at that time; capacity and non-fuel energy costs were recoverable through base rates. Witness McManeus presented the Company's position that the intent of the changes in fuel cost recovery afforded by Senate Bill 3 allows utilities to benefit their customers by allowing more timely cost recovery of the non-capacity costs of such purchases. She added that Duke Energy Carolinas has included the non-fuel energy component of economic power purchases in the fuel rates filed and approved in Docket Nos. E-7, Sub 847 and E-7, Sub 875. She also testified that these purchases have resulted in lower energy costs for the Company and its customers.

On cross-examination, witness McManeus acknowledged that G.S. 62-133.2(a1)(4) specifically includes the phrase "subject to economic dispatch or economic curtailment." Witness McManeus stated that she interpreted the statute to include purchases that were economic and not necessarily limited to dispatchable or curtailable purchases. In essence, if a purchase is economic, regardless of the dispatchability or curtailability, witness McManeus believed it should be recoverable. She also acknowledged that for each category of purchase at issue, Duke Energy Carolinas did not have the ability to dispatch or curtail power at will or at all. She agreed that the concept of dispatch or curtailment means that there has to be a decision made when the need arises or does not arise, and involves making a decision about whether to start or stop a purchase.

The Commission agrees with the Public Staff that G.S. 62-133.2(a1)(4) specifically and plainly provides for the inclusion in fuel and fuel-related costs of the noncapacity related costs of only those purchases "that are subject to economic dispatch or economic curtailment." In applying this statute, the Commission cannot ignore the words "dispatch" and "curtailment" in favor of the interpretation favored by the Company. Duke Energy Carolinas interprets this statute to include these costs if the purchases are economical, irrespective of the Company's ability to dispatch or curtail a purchase. Although economical purchases are laudable (and, as pointed out by witness Maness, are required of all public utilities), an interpretation that would permit the noncapacity related costs of all economical purchases to be included under G.S. 62-133.2(a1)(4), whether or not the purchases were dispatchable or curtailable, would not give full effect to the statute. Such a reading would violate the rule of statutory construction which requires that "[s]ignificance and effect should, if possible . . . be accorded every part of the act, including every section, paragraph, sentence or clause, phrase, and word." Hall v. Simmons, 329 N.C. 779, 784, 407 S.E. 2d 816, 818 (1991). See also N.C. Dept. of Correction v. N.C. Med. Bd., 363 N.C. 189, 201, 675 S.E. 2d 641, 649 (2009) ("Because the actual words of the legislature are the clearest manifestation of its intent, we give every word of the statute effect, presuming that the legislature carefully chose each word used.").

Since we cannot ignore the words "dispatch" and "curtailment," the issue becomes how to interpret the phrase "subject to economic dispatch or economic curtailment." The cardinal rule of statutory interpretation is that the intention of the legislature controls, and that intent is divined first by examining the plain language of the statute. State ex rel. Util. Comm'n v. Carolina Util. Customers Ass'n., Inc., 163 N.C. App. 46, 50, 592 S.E. 2d 221, 224, disc. rev. denied, 358 N.C. 739, 602 S.E. 2d 682 (2004). When the terms of a statute are clear and unambiguous, a Court is to apply the plain meaning of the words, with no need to resort to judicial construction. Wiggs v. Edgecombe Cty., 361 N.C. 318, 322, 643 S.E.2d 904, 907(2007) (citing Diaz v. Division of Soc. Servs., 360 N.C. 384, 387,628 S.E.2d 1, 3 (2006)).

The Public Staff cites the definition of "dispatch" in the IRC Staff Subcommittee Glossary of the National Association of Regulatory Utility Commissioners. This definition is "The control for an integrated electric system to schedule transactions with other interconnected electric utilities . . . to effect the most reliable and economical supply as the total of the significant area loads rises or falls." (Emphasis added.) The notion of dispatch (and curtailment) includes the ability to control when and if to take power on relatively short notice, as circumstances change. The Public Staff argues that if an electric public utility cannot control if and when to purchase power on relatively short notice, it is not recoverable under G.S. 62-133.2(a1)(4). What should be considered "relatively short notice" is obviously a matter that might be debated in any given proceeding; however, the Commission need not address that issue here. There are three categories of purchases at issue here: one is based upon the regulations of the FERC requiring the Company as a Transmission Provider to make imbalance purchases; the other two are based upon up-front contracts requiring the Company to make power purchases whenever the provisions of the contracts apply. In none of these cases does the Company have the control to make an individual dispatch decision at the time of an individual purchase. Company witness McManeus acknowledged that the transactions in question in this proceeding are not subject to Company dispatch or curtailment either at will or at all. The only decision that the Commission need make here is that the purchases contested by the Public Staff were not "subject to economic dispatch or economic curtailment," and we so conclude.

The Commission therefore concludes that the Company shall not be allowed to recover those system non-fuel energy expenses of purchases that are not subject to economic dispatch or economic curtailment and that the adjustments recommended by the Public Staff to exclude non-fuel energy costs related to the three categories of power purchases in question are appropriate and reasonable for purposes of this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The evidence for this finding of fact is found in the testimony and exhibits of Company witnesses Stroud, McManeus, Roebel, and Culp, and the affidavit of Public Staff witness Ellis.

Company witness Stroud testified regarding Duke Energy Carolinas' fossil fuel costs during the test year and changes expected in 2010 and 2011. Witness Stroud testified that the Company's delivered cost of coal during the test period increased from $80.36 per ton in 2008 to $89.87 per ton in 2009, and that the average mine price paid by Duke Energy Carolinas increased approximately 23% from $55.49 per ton in 2008 to $68.09 per ton in 2009. Witness Stroud explained that this increase was driven by the expiration of low-priced, long-term agreements that were replaced with higher-priced agreements executed during 2008.

Witness Stroud testified that the Company continues to focus on the Central Appalachia region as its primary source for coal. Coal markets overall have remained weak since Duke Energy Carolinas' 2009 fuel proceeding, but strengthened somewhat during the fourth quarter of 2009.

Additionally, witness Stroud testified that mining operating costs continue to have upward cost pressure due to growing demand for labor, declining mining productivity, and increasing regulations for mining safety. He further stated that increased regulation around permitting surface reserves has significantly affected Central Appalachia production, causing uncertainly around both whether existing permits will be upheld and whether new permits will be granted. Witness Stroud testified that none of these issues appear to be going away and that they are likely to get much worse. Because of the current instability of United States and world economic conditions, the Company expects much uncertainty for both the supply and demand for steam coal.

According to Company witness Stroud, during 2009, the Company focused on renegotiating long-term contracts and selling spot coal to ensure that inventories at stations did not exceed maximum storage capacity. Throughout late 2009 until the date of witness Stroud's pre-filed testimony, the Company had greater than 95% of its 2010 coal needs under firm prices, while only 20% of 2011 coal needs remain open to market prices.

Company witness Culp testified regarding Duke Energy Carolinas' nuclear fuel costs during the test year and changes expected in 2010 and 2011. Witness Culp stated that the impact on the Company of higher market prices for uranium concentrates during the test period was mitigated by contracts negotiated at lower market prices prior to 2007, which represented slightly more than 80% of the uranium purchased in the test period. Witness Culp noted that industry consultants expect spot market prices to remain high in comparison to historic norms as exploration, mine construction, and production gear up. Witness Culp further testified that market prices for enrichment have approximately doubled since the market lows experienced in calendar year 2000. He stated that 100% of the Company's enrichment purchases during the test period were delivered under long-term contracts negotiated at lower market prices prior to the test period. As such, the test period enrichment costs are comparable to the previous test period and notably less than market prices in the same period. Witness Culp testified that as these contracts expire, it is anticipated they will be replaced with contracts at higher market prices.

Witness Culp also testified that Duke Energy Carolinas anticipates a moderate increase in nuclear fuel expense through the next billing period. Because fuel is typically expensed over two to three operating cycles – roughly three to five years – Duke Energy Carolinas' nuclear fuel expense in the upcoming billing period will be determined by the cost of fuel assemblies loaded into the reactors during the test period as well as prior periods. He stated that the costs of the fuel residing in the reactors during the test period will be based predominantly on contracts negotiated prior to the recent market price increases. As fuel with a low cost basis is discharged from the reactor and lower priced legacy contracts expire, nuclear fuel expense is expected to increase in the future.

Witness Roebel testified as to Duke Energy Carolinas' reagent costs and net gains/losses from by-product sales during the test year and changes expected in 2010 and 2011. He testified that as additional environmental control equipment is placed in service, reagent costs are expected to increase. Expenses for limestone, ammonia, urea, and dibasic acid used in the operation of flue-gas desulfurization, selective catalytic reduction, and selective non-catalytic reduction equipment are projected to be approximately $30.4 million for the September 2010 through August 2011 billing period.

Witness Roebel testified that the Company seeks to sell by-products of the combustion or environmental treatment processes where there is a market for such materials as a means to minimize or offset the costs it would otherwise incur for their disposal. He also explained that although gypsum management activities required a net cost to complete, these net costs are significantly lower than the disposal costs the Company otherwise would incur. Net costs from the by-product management activities are expected to reach $2.6 million for the upcoming billing period.

Evidence concerning the reasonable and efficient operation of Duke Energy Carolinas' fossil-fueled, hydroelectric, and nuclear generating facilities is discussed above in the Evidence and Conclusions for Finding of Fact Nos. 4-6.

As set forth on or derived from McManeus Exhibit 1, Schedule 2(c), Page 1, witness McManeus recommended fuel and fuel-related prices and expenses as follows:

A. The coal fuel price is $37.42/MWh.
B. The oil and gas fuel price is $144.32/MWh.
C. The appropriate ammonia, limestone, urea and dibasic acid (collectively "Reagents") expense is $30,247,000.
D. The appropriate net cost on sale of by-products are $2,559,000.
E. The total nuclear fuel price is $5.36/MWh.
F. The nuclear fuel price for Catawba generation is $5.53/MWh.
G. The purchased power fuel price is $35.89/MWh.
H. The adjusted level of fuel and fuel-related credits associated with intersystem sales is $51,612,000.

Public Staff witness Ellis did not take issue with any of the Company's fuel costs in this proceeding except for those specific purchased power costs with which the Public Staff took issue, as discussed in the Evidence and Conclusions for Finding of Fact No. 9. In Ellis Second Revised Exhibit I, filed to reflect the refinement of the Public Staff's recommendation, as provided for in the testimony of Public Staff witness Maness, the Public Staff indicated that it was recommending an adjustment to the Company's prospective fuel expenses of $27,018,000, on a system basis. Based on this recommendation, it is derived that the Public Staff believes that the appropriate purchased power fuel price is $29.30/MWh.

Based upon the evidence in the record as to the appropriate fuel prices and expenses, as well as the Commission's Finding of Fact No. 9 in this Order, the Commission concludes that the fuel prices recommended by witness McManeus are reasonable and appropriate for this proceeding, except for the purchased power fuel price, for which the reasonable and appropriate amount is $29.30/MWh.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 11-15

The evidence for these findings of fact is contained in the testimony and exhibits of Company witness McManeus and the affidavits of Public Staff witnesses Maness, Johnson, and Ellis.

On July 19, 2010, the Public Staff filed Ellis Second Revised Exhibit I, to reflect the refinement of the Public Staff's recommendation regarding non-fuel purchased power expense, as provided for in the initial prefiled testimony of Public Staff witness Maness. This exhibit shows that the Public Staff recommends an adjusted test period system total fuel and fuel-related cost of $1,782,395,000, and fuel and fuel-related cost factors of 2.2845¢/kWh for the Residential class, 2.2841¢/kWh for the General Service/Lighting class, and 2.2840¢/kWh for the Industrial class, excluding gross receipts tax and regulatory fee. Pursuant to Ellis Second Revised Exhibit I and the Commission's Findings of Fact Nos. 4-10, the Commission concludes that the adjusted test period system fuel and fuel-related cost and fuel and fuel-related cost factors recommended by the Public Staff are reasonable and appropriate for use in this proceeding.

G.S. 62-133.2(d) provides that the Commission "shall incorporate in its fuel cost determination under this subsection the experienced over-recovery or under-recovery of reasonable fuel expenses prudently incurred during the test period . . . in fixing an increment or decrement rider. The Commission shall use deferral accounting, and consecutive test periods, in complying with this subsection, and the over-recovery or under-recovery portion of the increment or decrement shall be reflected in rates for 12 months, notwithstanding any changes in the base fuel cost in a general rate case."

In her affidavit, Public Staff witness Johnson testified about the results of the Public Staff's investigation of the EMF. The EMF rider is utilized to "true-up" the recovery of fuel and fuel-related costs incurred during the test year pursuant to G.S. 62-133.2(d) and Commission Rule R8-55. The Public Staff's investigation included procedures to evaluate whether the Company properly determined its per books fuel and fuel-related costs and revenues during the test period. These procedures included review of the Company's filing, prior Commission Orders, the Monthly Fuel Reports filed by the Company, and other Company data provided to the Public Staff. Additionally, the procedures included review of certain specific types of expenditures impacting the Company's test year fuel and fuel-related cost, including nuclear fuel disposal cost and payments to non-utility generators. Also, the Public Staff's procedures included reviews of source documentation of fuel and fuel-related costs for certain selected Company generation resources. Performing the Public Staff's investigation required the review of numerous responses to written and verbal data requests, as well as a site visit to the Company's offices. Other than the Public Staff's recommendation addressed in the Evidence and Conclusions for Finding of Fact No. 9, witness Johnson had no issues with the Company's calculation of its EMF.

On July 19, 2010, the Public Staff filed Maness Second Revised Exhibits I through IV, to reflect the refinement of the Public Staff's recommendation regarding non-fuel purchased power expense, as provided for in the initial prefiled testimony of Public Staff witness Maness. These exhibits show that the Public Staff's proposed North Carolina test period jurisdictional fuel and fuel-related expense over-collection, extended to include January 2010 through April 2010 pursuant to Commission Rule R8-55(d)(3), and net of the Fuel Over-Collection Rider (Docket E-7, Sub 909) implemented January 1, 2010, is $62,250,000, $59,969,000, and $28,917,000 for the Residential, General Service/Lighting, and Industrial classes, respectively. The proposed pro forma North Carolina retail jurisdictional sales are 21,013,802 MWh, 21,502,109 MWh, and 11,376,803 MWh for the Residential, General Service/Lighting, and Industrial classes, respectively. The Public Staff then calculated the EMF decrements for each class by dividing the over-collection for each class by the adjusted North Carolina jurisdictional sales for each class, to arrive at EMF decrements of 0.2962¢/kWh for the Residential class, 0.2789¢/kWh for the General Service/Lighting class, and 0.2542¢/kWh for the Industrial class, excluding gross receipts tax and regulatory fee. The Public Staff-proposed EMF interest decrements applicable to the net over-recovery are 0.0444¢/kWh, 0.0418¢/kWh, and 0.0381¢/kWh, respectively, for the Residential, General Service/Lighting, and Industrial classes, excluding gross receipts tax and regulatory fee. Pursuant to review of the Public Staff's calculations and Findings of Fact 4-10, the Commission concludes that the EMF decrements of 0.2962¢/kWh, 0.2789¢/kWh, and 0.2542¢/kWh for the Residential, General Service/Lighting, and Industrial classes, respectively, and EMF interest decrements of 0.0444¢/kWh, 0.0418¢/kWh, and 0.0381¢/kWh for the Residential, General Service/Lighting, and Industrial classes, respectively, excluding gross receipts tax and regulatory fee, are reasonable and appropriate for use in this proceeding.

Accordingly, the overall fuel calculation, incorporating the conclusions reached by the Commission in this Order, results in net fuel and fuel-related cost factors of 1.9439¢/kWh for the Residential class, 1.9634¢/kWh for the General Service/Lighting class, and 1.9917¢/kWh for the Industrial class, excluding gross receipts tax and regulatory fee. These net fuel and fuel-related cost factors consist of the prospective fuel factors of 2.2845¢/kWh, 2.2841¢/kWh, and 2.2840¢/kWh, for the Residential, General Service/Lighting, and Industrial classes, respectively; EMF decrements of 0.2962¢/kWh, 0.2789¢/kWh, and 0.2542¢/kWh for the Residential, General Service/Lighting, and Industrial classes, respectively; and EMF interest decrements of 0.0444¢/kWh, 0.0418¢/kWh, and 0.0381¢/kWh for the Residential, General Service/Lighting, and Industrial classes, respectively. Additionally, the Commission approves the uncontroverted continuation of the Nantahala area customer rider of 0.1539¢/kWh, excluding gross receipts tax and regulatory fee.

EVIDENCE AND CONCLUSION FOR FINDINGS OF FACT NOS. 16 AND 17

The evidence supporting these findings of fact is contained in the testimony and exhibits of Public Staff witness Maness. Public Staff witness Maness noted that the Public Staff found that the base fuel and fuel-related cost factor established by the Commission in Duke Energy Carolinas' most recent general rate case (Docket No. E-7, Sub 909) includes non-fuel energy costs associated with purchases from the same suppliers that contributed to the expenses that the Public Staff recommends be excluded from fuel and fuel-related costs in this proceeding. Witness Maness testified that these costs should be recovered only in base rates and that, if the Commission accepted the Public Staff's recommendation in this proceeding, then the base fuel and fuel-related cost factor set in Docket No. E-7, Sub 909 should be restated to exclude the non-fuel energy expenses of purchases that should not have been included therein. He testified that this would be necessary in order to accurately (1) compare fuel revenues and fuel expenses for purposes of determining the EMFs in the Company's annual fuel and fuel-related cost proceedings until its next general rate case and (2) state the base and rider components of the total factors set in those proceedings. Witness Maness testified that the Public Staff had recalculated the base fuel and fuel-related cost factor in this fashion as shown on Maness Exhibit III. On July 19, 2010, the Public Staff filed Maness Second Revised Exhibits I through IV, to reflect the refinement of the Public Staff's recommendation regarding non-fuel purchased power expense, as provided for in his initial prefiled testimony. Maness Second Revised Exhibit III shows that the Public Staff's recommended restated base fuel and fuel-related cost factor is 2.3284¢/kWh, excluding gross receipts tax and regulatory fee. After careful consideration and consistent with Finding of Fact No. 9, the Commission agrees with the Public Staff's recommendation that these costs should be recovered only in base rates and, therefore, that the base fuel and fuel-related cost factor set in Docket No. E-7, Sub 909 should be restated. Therefore, effective as of September 1, 2010, the base fuel and fuel-related cost factor is 2.3284¢/kWh.

Public Staff witness Maness concluded his testimony by recommending a rider that would allow the Company to continue to recover the difference between the base fuel and fuel-related cost factor originally established in Docket No. E-7, Sub 909 and the restated base fuel and fuel-related cost factor that he recommended the Commission adopt in this order. In Maness Second Revised Exhibit IV, filed on July 19, 2010, the Public Staff recommended that this rider be set at 0.0205¢/kWh. After careful consideration and consistent with Finding of Fact No. 9, the Commission agrees that it is reasonable to conclude that the non-fuel energy expenses of purchases that the Commission is excluding from the Company's base fuel factor would have been included in the non-fuel portion of the Company's revenue requirement and that such a rider is appropriate. This is similar to the Commission's approach on a similar issue in the 1988 Virginia Electric and Power Company fuel proceeding, Docket No. E-22, Sub 304, as noted by witness Maness. Based on a review of Maness Second Revised Exhibit IV, the Commission agrees that the Public Staff's recommended rider is appropriate and reasonable. Therefore, effective for service rendered on and after September 1, 2010, the Commission authorizes Duke Energy Carolinas to include in its rates and charges to its North Carolina retail customers a rider of 0.0205¢/kWh, to remain in effect until the next approved adjustment to North Carolina retail rates that incorporates such costs into overall base rates.

IT IS, THEREFORE, ORDERED:

1. That, effective for service rendered on and after September 1, 2010, Duke Energy Carolinas shall adjust the base fuel and fuel-related cost factors in its North Carolina retail rates of 2.3491¢/kWh for the Residential class, 2.3475¢/kWh for the General Service/Lighting class, and 2.3515¢/kWh for the Industrial class, as approved in Docket E-7, Sub 875 and adjusted in

Docket E-7, Sub 909 by decrements of 0.0646¢/kWh, 0.0634¢/kWh, and 0.0675¢/kWh, respectively (excluding gross receipts tax and regulatory fee); and, further, that Duke Energy Carolinas shall adjust the resultant approved fuel and fuel-related cost factors for EMF decrements of 0.2962¢/kWh for the Residential class, 0.2789¢/kWh for the General Service/Lighting class, and 0.2542¢/kWh for the Industrial class (excluding gross receipts tax and regulatory fee) and for EMF interest decrements of 0.0444¢/kWh for the Residential class, 0.0418¢/kWh for the General Service/Lighting class, and 0.0381¢/kWh for the Industrial class (excluding gross receipts tax and regulatory fee). The EMF decrements and EMF interest decrements are to remain in effect for service rendered through August 31, 2011.

2. That the Nantahala Area Customer Rider of 0.1539¢/kWh, excluding gross receipts tax and regulatory fee, shall remain in effect for service rendered through August 31, 2011, in order to continue to recover net deferred purchased power costs.

3. That, effective September 1, 2010, the base fuel and fuel-related cost factor is 2.3284¢/kWh.

4. That, effective for service rendered on and after September 1, 2010, the Commission authorizes Duke Energy Carolinas to include in its rates and charges to its North Carolina retail customers a rider of 0.0205¢/kWh, to remain in effect until the next approved adjustment to North Carolina retail rates that incorporates such costs into overall base rates.

5. That Duke Energy Carolinas shall file appropriate rate schedules and riders with the Commission in order to implement these approved rate adjustments no later than 10 days from the date of this Order.

6. That Duke Energy Carolinas shall work with the Public Staff to prepare a joint notice to customers of the rate changes ordered by the Commission in this docket, as well as in Docket No. E-7, Sub 936, and the Company shall file such notice for Commission approval within five (5) days after the Commission issues its orders in both dockets.

ISSUED BY ORDER OF THE COMMISSION.
This the 6th day of August, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

mr080110.01

DOCKET NO. E-2, SUB 968

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of:		
Application of Progress Energy Carolinas, Inc. for a Certificate of Public Convenience and Necessity to Construct Approximately 620 MW of Combined Cycle Generating Capacity at its New Hanover County Facility near Wilmington, North Carolina	)	ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

HEARD: Judicial Building, Courtroom 300, 314 Princess Street, Wilmington, North Carolina, on Tuesday, February 23, 2010, at 7:00 p.m., and

Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on Wednesday, March 31, 2010, at 9:00 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 Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc.:

Len S. Anthony, General Counsel - Progress Energy Carolinas, Inc. and Kendal C. Bowman, Associate General Counsel, Post Office Box 1551, Raleigh, North Carolina 27602-1551

For the Using and Consuming Public:

Dianna Downey, 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: Commission Rule R8-61(a) requires a utility seeking a certificate of public convenience and necessity to construct a generating facility with a capacity of 300 megawatts (MW) or more to file with the Commission certain information 120 days prior to filing the application for the certificate. Commission Rule R8-61(b)(4) requires updates to the information to be filed with the application. On December 4, 2009, Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc. (PEC), filed a motion for waiver of Commission Rule R8-61(a) and (b)(4) with regard to PEC's proposed application for a certificate of public convenience and necessity to construct a generating facility to replace PEC's three coal-fired generating units at its Sutton Plant in New Hanover County. In support of its motion, PEC stated that the proposed facility will be constructed at an existing generation site and that PEC needs to begin construction soon given the current low cost for equipment and services. PEC also stated that both the Public Staff – North Carolina Utilities Commission (Public Staff) and the North Carolina Attorney General had agreed that the prefiling was not necessary under the circumstances. On December 15, 2009, the Commission issued its Order Granting Waiver of Prefiling Requirement.

On December 18, 2009, PEC filed an Application for a Certificate of Public Convenience and Necessity (Application) pursuant to G.S. 62-110.1 and Commission Rule R8-61, along with the supporting testimony of Glen A. Snider, Manager – Resource Planning. PEC proposes to construct approximately 620 MW of combined-cycle (CC) natural gas-fired generating capacity at its existing Sutton Plant generation site in New Hanover County near Wilmington, North Carolina. The planned in-service date of the facility is December 2013.

On December 30, 2009, Attorney General Roy Cooper gave Notice of Intervention in this docket on behalf of the using and consuming public pursuant to G.S. 62-20. Intervention and participation by the Public Staff is made and recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

On January 5, 2010, the Commission issued its Order Scheduling Hearings, Establishing Procedural Deadlines and Requiring Public Notice. Pursuant to this Order, a public hearing for the purpose of taking public witness testimony was scheduled on February 23, 2010, in Wilmington and an evidentiary hearing was scheduled on March 31, 2010, in Raleigh. The Commission also required PEC to give public notice of the application and hearings, and PEC properly published notice.

The public hearing in Wilmington was held on February 23, 2010, as scheduled. No public witnesses testified at the public hearing.

On March 16, 2010, the Public Staff filed the affidavits of Kennie D. Ellis, Engineer – Electric Division, and Darlene P. Peedin, Supervisor, Electric Section – Accounting Division, together with a notice that the affidavits would be used in evidence at the hearing pursuant to G.S. 62-68.

On March 25, 2010, PEC filed a motion to excuse its witness Glen A. Snider from appearing at the March 31, 2010 evidentiary hearing and to allow the introduction of all prefiled direct testimony, exhibits, and affidavits into the record. PEC stated that all parties had agreed to waive cross-examination of witness Snider and the Public Staff's witnesses. This motion was allowed by Commission Order issued March 26, 2010.

On March 31, 2010, the hearing was held in Raleigh as scheduled. No public witnesses appeared to testify at the hearing. The prefiled direct testimony and exhibits of PEC witness Glen A. Snider were received into evidence as if given orally. The affidavits of Public Staff witnesses Kennie D. Ellis and Darlene P. Peedin together with the respective appendices, were also received into evidence as if given orally. The hearing was then concluded.

On May 11, 2010, PEC filed a proposed order, and on May 12, 2010, the Public Staff filed a letter stating that it supported adoption of PEC's proposed order.

Based upon consideration of all the evidence admitted during the hearings and the entire record of this proceeding, the Commission makes the following:

FINDINGS OF FACT

1. PEC is a North Carolina corporation 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 North Carolina Utilities Commission as a public utility. PEC is lawfully before this Commission based upon its application filed pursuant to G.S. 62-110.1 and Commission Rule R8-61.

2. PEC owns and operates three coal-fired electric generating units with a combined generating capacity of approximately 600 MW at its Sutton Plant site in New Hanover County. None of the Sutton coal-fired units have any form of flue gas desulfurization to limit their emissions of sulfur dioxide (SO_2) and mercury. None of the units have any environmental controls to limit their emissions of greenhouse gases (GHG).

3. If PEC continues to operate the Sutton coal-fired units, state and federal laws and regulations will require PEC to make significant investments to install nitrogen oxide (NO_x), SO_2, and mercury emissions controls.

4. If PEC continues to operate the Sutton coal-fired units, it is possible that new federal regulations or legislation will require PEC to reduce its emissions of GHG.

5. If PEC continues to operate the Sutton coal-fired units, it will have to construct a new ash pond, convert to dry ash storage, or arrange for offsite storage in order to dispose of coal combustion products (CCP) generated by the operation of the units.

6. PEC seeks a certificate of public convenience and necessity to construct approximately 620 MW of CC natural gas-fired generating capacity at the Sutton Plant site. The proposed facility will consist of two combustion turbines and two heat recovery steam generators to produce steam to drive a single steam turbine. The facility will be equipped with duct firing capability which will increase its generating capacity to approximately 620 MW during peak conditions.

7. It is more cost effective for PEC to retire its existing Sutton coal-fired units and replace them with the proposed CC generating facility than to install the environmental controls and incur the handling, disposal, and storage costs necessary to allow their continued operation.

8. Since PEC plans to cease operation of the coal-fired units at the Sutton Plant site upon completion of the proposed CC generating facility of essentially the same capacity at the same site, PEC is not requesting approval to construct any net additional generating capacity in this proceeding.

9. The proposed CC generating facility is the appropriate substitution for the coal-fired units, as opposed to alternative types of generation.

10. Generation is critical in the general location of the Sutton Plant site for voltage support to both the Brunswick Nuclear Plant and the eastern part of the PEC system. The existing site has the necessary infrastructure to support the proposed CC generating facility, and minimal investment would be required to connect to PEC's transmission system.

11. Due to the uniqueness of the present circumstances and the criticality of generation at the Sutton location, PEC has proceeded appropriately in its pursuit of self-built generation at the Sutton plant site.

12. The process being implemented to plan and construct the proposed CC generating facility and PEC's construction cost estimate are reasonable and should be approved.

13. It is reasonable and appropriate to issue a certificate of public convenience and necessity for the construction of the proposed CC generating facility at the Sutton Plant site, subject to the following conditions recommended by the Public Staff:

a. That the facility certificated in this order shall be constructed and operated in strict accordance with all applicable laws and regulations, including the provisions of all permits issued by the North Carolina Department of Environment and Natural Resources;

b. That PEC shall file with the Commission in this docket a progress report and any revisions in the cost estimate for this facility on an annual basis, with the first report due no later than one year from the date of this order;

c. That, immediately upon completion of the construction of and placement into service of the CC facility, PEC shall permanently cease operation of the three coal-fired generating units at its Sutton Plant facility and shall file with the Commission in this docket a notice that operation of all of the coal-fired generation at the Sutton Plant has ceased;

d. That issuance of this order does not constitute approval of the final costs associated with the construction of the CC generation at the Sutton Plant site for ratemaking purposes, and this order is without prejudice to the right of any party to take issue with the ratemaking treatment of the final costs in a future proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

This finding is essentially informational, procedural, and jurisdictional in nature and is not controversial.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 2-5

The evidence supporting these findings of fact is contained in PEC's Application and in the testimony of PEC witness Snider.

The evidence shows that PEC operates three coal-fired units with a total generating capacity of approximately 600 MW at its Sutton Plant site in New Hanover County. PEC faces many environmental compliance challenges in connection with the Sutton units. These challenges include the following: none of the Sutton coal units have any flue-gas desulfurization equipment to limit their emissions of SO_2 and mercury, and the existing ash pond at the Sutton Plant site will reach full capacity on or before 2014.

PEC states that in 2006, North Carolina adopted mercury emission regulations (N.C. Mercury Rules). The N.C. Mercury Rules establish mercury limits, allocate emission allowances, and require all coal-fired units to have mercury-control technology installed no later than December 31, 2017. The N.C. Mercury Rules require PEC to develop an emission control plan for each operating unit by January 1, 2013, that will identify a schedule for installation and operation of mercury controls. In addition, the United States Environmental Protection Agency (EPA) is currently developing Maximum Achievable Control Technology standards for mercury and other hazardous air pollutants emitted by steam generators.

PEC states that both the North Carolina Clean Smokestacks Act and the federal Clean Air Interstate Rule (CAIR) require reductions in SO_2 emissions. The Clean Smokestacks Act requires PEC to reduce its annual North Carolina emissions of SO_2 from its coal-fired plants to 50,000 tons or fewer by January 1, 2013. PEC plans to achieve this required reduction by retiring the Lee coal-fired units. In addition, North Carolina has adopted rules implementing the federal CAIR (N.C. CAIR). N.C. CAIR incorporated the CAIR allowance trading system under which an entity could either reduce its emissions to the required limit, purchase sufficient allowances to comply with the rule's requirements, or undertake a combination of both. In 2008, the Court of Appeals for the District of Columbia Circuit at first vacated federal CAIR and then, in December 2008, modified its earlier opinion to remand the case to EPA without vacatur for further proceedings. In the interim, CAIR and N.C. CAIR remain in effect while EPA develops a revised rule. PEC anticipates that the revised CAIR will require additional reductions of SO_2 and NO_x and will require point-specific controls, rather than allowance trading.

PEC also states that on December 7, 2009, EPA issued a final "endangerment finding," declaring that carbon dioxide (CO_2) and five other GHG emissions are pollutants that threaten public health and welfare. This finding gives EPA the authority to regulate CO_2 under the Clean Air Act. Concurrently, Congress is considering legislation to regulate GHG. The American Clean Energy and Security Act of 2009, also known as the Waxman-Markey bill, was approved by the House of Representatives on June 26, 2009, and in the Senate, the Clean Energy Jobs and American Power Act, also known as the Kerry-Boxer bill, has been introduced and approved by a key committee. Even in the absence of Congressional action, the EPA regulatory efforts are expected to continue. The EPA's endangerment finding provides a basis for regulating CO_2 and raises the possibility of new requirements being imposed in future and current air emission permits. Additionally, PEC cites two recent federal appellate court decisions which suggest that regulation of GHG may occur through legal actions based upon state law claims for nuisance, trespass, or negligence.

Finally, PEC states that EPA is currently considering re-characterizing the nature and regulation of CCP (coal combustion products such as bottom ash, fly ash, and related materials) in response to the ash pond impoundment failure at TVA's Kingston Plant. If EPA increases the regulatory requirements applicable to CCP, the handling, storage, and disposal of CCP may result in significantly increased costs. The phase-out of surface impoundments is also under consideration by EPA. Since the current ash pond at PEC's Sutton Plant site will reach full capacity on or before 2014, PEC must incur significant costs to construct a new ash pond or convert to dry ash handling together with onsite disposal or transportation for offsite disposal, even if EPA does not increase regulatory requirements for CCP.

None of the parties to this proceeding disputed PEC's description of the environmental compliance challenges associated with the future operation of coal-fired generation.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 6-13

The evidence supporting these findings of fact is found in PEC's Application and in the testimony of PEC witness Snider and the affidavits of Public Staff witnesses Ellis and Peedin.

Given the environmental compliance challenges associated with coal-fired generation, PEC evaluated the cost effectiveness of continuing to operate the Sutton coal-fired units. PEC concluded that simply retiring these coal units is not an option due to voltage support requirements in this area of PEC's system. PEC witness Snider testified that voltage support requirements in the eastern region and the needs of the Brunswick Nuclear Plant require PEC to have approximately 600 MW of generating capacity at a location that is essentially the same as the Sutton Plant site.

Regarding the type of generation that should be considered to replace the Sutton coal units, PEC witness Snider relied upon the information in PEC's 2008 Integrated Resource Plan and 2009 update. According to witness Snider, these documents demonstrate that gas-fired generators are the most environmentally benign and economical large-scale capacity additions available for meeting peak and intermediate loads. New designs of these technologies are more efficient (as measured by heat rate) than previous designs, resulting in a smaller impact on the environment. The advancements associated with CC generation provide greater operational flexibility relative to combustion turbines without heat recovery steam generators and steam turbines. This is due to several factors. First, each combustion turbine can be operated in a simple-cycle mode or in concert with its heat recovery steam generator and the steam turbine to enhance reliability and optimize unit operations. Second, the proposed CC facility has approximately 70 MW of duct firing capability that can be dispatched during peak demand periods, much as a peaker would be dispatched, but at a fraction of the cost of installing an additional combustion turbine. Third, a CC generating facility can be economically utilized across a wide capacity range, approximately 30% to 60%, which means that it can grow with system energy needs, unlike oil-fired combustion turbines, which are logistically and environmentally hindered from operating at capacity factors greater than roughly 5% to 10%.

Witness Snider also noted that CC technology has an additional benefit within PEC's balanced solution of providing fuel diversity and lowering long-term fuel price volatility.

Witness Snider further testified that a CC facility fueled by natural gas is the cleanest and most efficient fossil-fueled generation currently available. There are virtually no SO_2 emissions, NO_x emissions are approximately 80% less than new coal-fired generation, and CO_2 emissions are approximately 60% less than new coal-fired generation.

PEC compared the cost of building a new approximately 620-MW CC natural gas-fired generator at the Sutton Plant site to the cost of continuing to operate the three existing coal-fired units, including the cost of modifications that could be required by new environmental regulations. According to PEC, continued operation of the coal units will require new SO_2, NO_x, and mercury emission controls as early as 2015. Continued operation will also require a new permitted landfill for ash and other CCP. Retiring these coal units will eliminate the need for these controls and the new landfill, saving almost $720 million in capital expenditures. Retiring the coal units will also avoid ongoing operations and maintenance (O&M) costs and capital expenditures for the units, estimated at over $670 million in O&M and over $285 million in capital through the 2009-2039 study period. These cost savings are partially offset, however, by O&M and capital expenditures for the proposed CC facility.

PEC described the economic analysis of the proposed CC facility, performed in terms of cumulative present value of revenue requirements (CPVRR). The costs associated with the continued operation of the coal units were: the ongoing O&M costs; the capital costs to operate and maintain the units; the cost of adding emission controls to the units; a new ash landfill for the plant; and the cost of CO_2 emissions, i.e., the difference in CO_2 emissions between the case with the proposed CC facility and the case with the coal units' continued operation. For the proposed CC facility, the cost components were: the ongoing O&M and capital costs of the coal units until they are retired at the end of 2013; the O&M and capital costs of the proposed CC facility; the natural gas pipeline reservation costs; and the change in total system fuel and purchased power costs from continued coal operation. Among the costs included in the CPVRR of continued coal operations were $795 million of costs associated with SO_2 and NOx environmental controls. PEC evaluated the likelihood of being required to install these controls and concluded that new regulation and management of emissions and CCP was highly probable and that inclusion of these costs in the analysis was appropriate. PEC stated that three of the key uncertainties in retiring and replacing the coal units are the cost of natural gas, the cost of coal, and the cost of CO_2 emissions. PEC stated that construction of a new landfill for ash disposal would require a county "special use" permit. If a landfill for ash cannot be built at the Sutton Plant site, the CCP would have to be transported to another location at an assumed cost of $55/ton. This would increase the cost of continuing to operate the coal units by over $440 million through the 2009-2039 study period.

According to PEC, the total savings associated with retiring the coal units and replacing them with the proposed CC facility is approximately $90 million. If transporting the CCP is required, the savings would be more than $192 million. PEC concluded that, given the range of variables and the evaluation of uncertainties, building the proposed CC facility at the Sutton Plant site is the most cost effective and robust decision.

Witness Snider also described the process being proposed by PEC to plan and construct the CC facility. He testified that since 1997, PEC has placed in-service approximately 2,230 MW of new combustion turbines and 480 MW of CC generating capacity. PEC has extensive experience in both negotiating the purchase of these facilities and installing and constructing them. The proposed CC facility would be the result of a competitive bidding process. PEC would invite proposals from different equipment vendors for the purchases of the combustion turbine generators and other items of major equipment. PEC would also request bids from available and qualified engineering and construction firms to construct the facility.

Public Staff witness Ellis stated in his affidavit that the Public Staff investigated and determined that generation in the general location of the Sutton Plant site is critical for voltage support to both the Brunswick Nuclear Plant and the eastern part of the PEC system. Therefore, if PEC retires the Sutton coal units, it must replace them with some other form of generation near the same location. Witness Ellis noted that, because PEC is not requesting approval to construct net additional generating capacity in this proceeding, it is unnecessary for the Commission to consider whether PEC's proposal is consistent with the analysis of long-range needs for expansion of facilities for generation of electricity required by G.S. 62-110.1(c). Witness Ellis stated that, while mindful of the Commission's expectation expressed in Docket No. E-100, Sub 122, that in future CPCN proceedings electric utilities should "provide evidence of a robust and thoughtful review of opportunities in the wholesale market" and "employ the use of competitive bidding and/or third-party evaluators as necessary and appropriate," the Public Staff believes that PEC proceeded appropriately in its pursuit of self-built generation given the uniqueness of the present circumstances and the criticality of having generation at the Sutton Plant site.

Public Staff witness Ellis did not identify any major concerns regarding the process being proposed by PEC to plan and construct the CC units. He stated that PEC has the experience to manage the construction of the CC units, thus avoiding the incremental costs associated with a third party provider. He noted that PEC is competitively bidding all large equipment and engineering, procurement, and construction services and would take advantage of economies of scale by soliciting bids for equipment and services to both the Wayne County facility and the proposed Sutton CC facility at the same time.

Public Staff witness Peedin agreed that the results of PEC's base case economic analysis shows that there is a benefit in retiring the Sutton coal units and replacing them with the proposed CC natural gas-fired facility. She also stated that PEC's analysis, in comparing the cost of continuing to operate the coal units with constructing and operating the proposed CC facility, used reasonable methodologies and assumptions consistent with previous evaluations of generation additions found to be acceptable by the Commission, and that the analysis was conducted in a satisfactory manner. Additionally, she stated that it appears that, based on PEC's assumptions, the estimated cost of the proposed CC facility is comparable on a per-kW basis to other recent additions of CC facilities in the State and that PEC's proposal and cost estimate to build the proposed CC facility are reasonable and should be approved.

Only PEC and the Public Staff presented evidence in this proceeding. The evidence supports the retirement of the existing Sutton coal units and replacing them with the proposed

620-MW natural gas-fired CC electric generating facility. The granting of a certificate for the new facility requires Commission approval of the cost estimate for the construction being proposed and a finding that the construction is consistent with the Commission's plan for expansion of electric generating capacity. Public Staff witness Ellis concluded that, because PEC is not requesting approval of any net additional generating capacity, it is unnecessary to consider whether PEC's proposal is consistent with the analysis of long-range needs for expansion of facilities for generation of electricity required by G.S. 62-110.1(c). The Commission finds and concludes that, because PEC is proposing to retire existing generation and replace it with essentially the same amount of new generation at the same site and, thus, is essentially requesting no net additional generating capacity, PEC's proposal is consistent with long-range needs for expansion of electric generating facilities in the State. Public Staff witness Peedin concluded that PEC's cost estimate to build the proposed CC facility is reasonable and should be approved. The Commission so finds, but notes that its approval is made only in the context of this proceeding and does not apply to any ratemaking determination or proceeding. The Commission notes that PEC is required by G.S. 62-110.1(f) to provide an annual progress report and any revisions to its cost estimate, and the Commission so requires.

The Commission finds that PEC's Application for a Certificate of Public Convenience and Necessity to construct a 620-MW CC natural gas-fired electric generating facility at the Sutton Plant site in New Hanover County should be granted, subject to the following conditions recommended by the Public Staff, which the Commission finds to be appropriate:

1. That the facility certificated in this order shall be constructed and operated in strict accordance with all applicable laws and regulations, including the provisions of all permits issued by the North Carolina Department of Environment and Natural Resources;

2. That PEC shall file with the Commission in this docket a progress report and any revisions in the cost estimate for this facility on an annual basis, with the first report due no later than one year from the date of this order;

3. That immediately upon completion of the construction and placement into service of the CC facility, PEC shall permanently cease operation of the three coal-fired generating units at its Sutton Plant facility and shall file with the Commission in this docket a notice that operation of all of the coal-fired generation at the Sutton Plant has ceased;

4. That issuance of this order does not constitute approval of the final costs associated with the construction of the CC generation at the Sutton Plant site for ratemaking purposes, and this order is without prejudice to the right of any party to take issue with the ratemaking treatment of the final costs in a future proceeding.

IT IS, THEREFORE, ORDERED as follows:

1. That a certificate of public convenience and necessity should be, and hereby is, granted to PEC to construct a 620-MW CC natural gas-fired electric generating facility to be located at the Sutton Plant site in New Hanover County subject to the above conditions and the following ordering paragraphs, and this order shall constitute the certificate;

2. That the facility certificated herein shall be constructed and operated in strict accordance with all applicable laws and regulations, including the provisions of all permits issued by the North Carolina Department of Environment and Natural Resources;

3. That PEC shall file with the Commission in this docket a progress report and any revisions in the cost estimate for this facility on an annual basis, with the first report due no later than one year from the date of this order;

4. That PEC shall permanently cease operation of the three coal-fired units at its Sutton Plant site immediately upon completion of construction and placement into service of the CC facility certificated herein and shall file with the Commission a notice that operation of all coal-fired generation at the Sutton Plant site has ceased; and

5. That issuance of this Order does not constitute approval of the final costs associated with the construction of the CC facility at the Sutton Plant site for ratemaking purposes, and this Order is without prejudice to the right of any party to take issue with the ratemaking treatment of the final costs in a future proceeding.

ISSUED BY ORDER OF THE COMMISSION.
This the 9th day of June, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Sk060710.01

DOCKET NO. E-7, SUB 906

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Request of Duke Energy Carolinas, LLC,	)	ORDER EXTENDING
for Extension of Residential Energy	)	RESIDENTIAL ENERGY
Management System Pilot	)	MANAGEMENT SYSTEM PILOT

BY THE COMMISSION: On June 2, 2010, Duke Energy Carolinas, LLC (Duke), filed a request to extend its Residential Energy Management System Pilot (EMS Pilot) through September 2011. The Commission approved the EMS Pilot by Order issued on March 10, 2009. Duke initially planned to cancel the EMS Pilot in September 2010. Due to a mild summer in 2009 and Duke's desire to test new equipment, however, Duke now is seeking approval to extend the EMS Pilot for another year and to allow up to 50 new customers to participate for the purposes of gaining additional summer load experience and testing the new equipment. Duke initially expected an enrollment of approximately 200 participants, but only 91 participants enrolled in the EMS Pilot. Duke indicates that approximately 50 of the current participants will elect to terminate their participation at the end of the pilot period in September 2010.

Participants in the EMS Pilot allow Duke to install an energy management system in their homes. Using an online energy management website, participants can obtain detailed information about their energy use and adjust their consumption in response to price signals. Participants are also able to manage their energy consumption by controlling both the times that various appliances operate and the temperature settings for space heating and air conditioning. Participants can also elect to allow Duke to manage their energy use based on a personal energy profile.

Participants receive one-time incentives at the beginning and end of the EMS Pilot and additional monthly incentives based on their equipment settings and energy use profile.

In the Commission's March 20, 2009 Order approving the EMS Pilot, the Commission required Duke to file a report by December 31, 2010, detailing the measurement, verification, and evaluation (M&V) of data obtained from the pilot. In its June 2, 2010 request, Duke indicates that it will file its M&V report by December 31, 2010, for the current participants in the EMS Pilot and a supplemental M&V report by December 31, 2011, for the additional participants in the extended EMS Pilot.

Duke has further indicated to the Public Staff that, consistent with the initial EMS Pilot, it will not seek cost recovery or program incentives for the initial and extended EMS Pilot as provided under Commission Rule R8-69.

The Public Staff presented this matter to the Commission at its regular Staff Conference on June 21, 2010, and recommended that the Commission approve Duke's request to extend its EMS pilot and require Duke to provide a supplemental evaluation of the results to the Commission and the Public Staff no later than December 31, 2011.

Based on its review of Duke's filing and the recommendation of the Public Staff, the Commission concludes that Duke's request to extend the EMS Pilot should be granted.

IT IS, THEREFORE, ORDERED as follows:

1. That Duke's Residential Energy Management System Pilot is extended through September 2011.

2. That Duke shall file the results of its measurement, verification, and evaluation of the EMS Pilot associated with the current participants no later than December 31, 2010, and a supplemental evaluation of the extension of the EMS Pilot no later than December 31, 2011. Duke may file the results under seal, if necessary.

ISSUED BY ORDER OF THE COMMISSION.
This the 22nd day of June, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Commissioner ToNola D. Brown-Bland did not participate in this decision.

Pb062210.02

DOCKET NO. E-7, SUB 831

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Duke Energy Carolinas, LLC for Approval of Save-a-Watt Approach, Energy Efficiency Rider and Portfolio of Energy Efficiency Programs	) ORDER APPROVING AGREEMENT AND JOINT) STIPULATION OF SETTLEMENT SUBJECT TO) CERTAIN COMMISSION-REQUIRED) MODIFICATIONS AND DECISIONS ON) CONTESTED ISSUES

HEARD IN: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina on August 19, 2009

BEFORE: Chairman Edward S. Finley, Jr., Presiding; and Commissioners Robert V. Owens, Jr., Lorinzo L. Joyner, and William T. Culpepper, III

APPEARANCES:

For Duke Energy Carolinas, LLC:

Lara Simmons Nichols, Associate General Counsel, and Catherine E. Heigel, Associate General Counsel, Duke Energy Corporation, 526 South Church Street, 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:

Kendrick C. Fentress, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699

Leonard G. Green, Assistant Attorney General, North Carolina Department of Justice, P.O. Box 629, Raleigh, North Carolina 27602

For N.C. Waste Awareness & Reduction Network (NC WARN):

John D. Runkle, Attorney at Law, P.O. Box 3793, Chapel Hill, North Carolina 27515

For North Carolina Justice Center (NCJC), AARP, North Carolina Council of Churches (NCCC), and Legal Aid of North Carolina (LANC):

Jack Holtzman, North Carolina Justice Center, 224 South Dawson Street, Raleigh, North Carolina 27601

For the Carolina Industrial Group for Fair Utility Rates (CIGFUR III) and Air Products and Chemicals, Inc.:

Ralph McDonald, Bailey & Dixon, LLP, P.O. Box 1351, Raleigh, North Carolina 27602

For the Carolina Utility Customers Association, Inc. (CUCA):

Robert F. Page, Crisp, Page, & Currin, LLP, Suite 205, 4010 Barrett Drive, Raleigh, North Carolina 27603

For Environmental Defense Fund, Natural Resources Defense Council, Southern Alliance for Clean Energy and Southern Environmental Law Center:

Gudrun Thompson, Southern Environmental Law Center, 200 West Franklin Street, Suite 330, Chapel Hill, North Carolina 27516

For North Carolina Sustainable Energy Association:

Kurt J. Olson, North Carolina Sustainable Energy Association, 111 Haynes Street, Suite 109, Raleigh, North Carolina 27628

BY THE COMMISSION: On May 7, 2007, Duke Energy Carolinas, LLC (Duke, Company) filed an application in this docket for approval of its save-a-watt approach, energy efficiency rider, and portfolio of energy efficiency.

The following parties have been allowed to intervene in this matter: the North Carolina Attorney General; the Public Staff – North Carolina Utilities Commission (Public Staff); the Carolina Utility Customers Association, Inc. (CUCA); the Carolina Industrial Group for Fair Utility Rates (CIGFUR III); Piedmont Natural Gas Company, Inc. (Piedmont); the Southern Alliance for Clean Energy (SACE); the North Carolina Waste Awareness & Reduction Network, Inc. (NC WARN); Virginia Electric and Power Company d/b/a Dominion North Carolina Power (Dominion); Progress Energy Carolinas, Inc. (PEC); the North Carolina Sustainable Energy Association (NCSEA); Public Service Company of North Carolina, Inc. (PSNC); the City of Durham; Wal-Mart Stores East, LP (Wal-Mart); Environmental Defense (ED); the Southern Environmental Law Center (SELC); Air Products and Chemicals, Inc. (Air Products); the North Carolina Justice Center (NCJC), AARP, North Carolina Council of Churches (NCCC) and Legal Aid of North Carolina (LANC) (collectively, the Public Interest Intervenors); and the Natural Resources Defense Council (NRDC).

On May 24, 2007, Piedmont filed a motion for establishment of a generic proceeding. On May 31, 2007, the Commission entered an order requesting comments regarding the statutory authority for the relief requested by Duke and the appropriateness of converting this docket into a generic investigation as requested by Piedmont. PEC and Dominion filed comments on June 20, 2007; Duke, the Attorney General, the Public Staff, CUCA, CIGFUR III, SACE, NCSEA, and PSNC filed comments on June 22, 2007; NC WARN filed comments on

June 25, 2007; Dominion filed further comments on June 29, 2007; and the City of Durham filed initial comments on July 3, 2007. Reply comments were filed by Duke, PEC, PSNC, SACE, the Public Staff, NCSEA, CIGFUR III, and Piedmont on July 13, 2007; and the City of Durham filed reply comments on July 16, 2007. The Henderson County Chamber of Commerce filed notice of its support of Duke's proposed energy efficiency plan on July 12, 2007 and August 3, 2007.

On August 2, 2007, the Commission issued an order denying Piedmont's petition for establishment of a generic proceeding and consolidating Duke's application in this docket with Docket Nos. E-7, Subs 828 and 829 and E-100, Sub 112, dockets which the Commission had consolidated earlier for purposes of hearing. Docket No. E-7, Sub 828 was Duke's then-pending general rate case proceeding. At that time, the Commission acknowledged that pending legislation (Senate Bill 3) would address the Commission's authority to examine energy efficiency programs and cost recovery for such programs outside of general rate cases. However, because Senate Bill 3 had not yet been enacted and the Commission was concerned with losing its opportunity to consolidate the energy efficiency docket with the general rate case, the Commission consolidated the dockets, reserving the right for reconsideration.

On August 14, 2007, Duke moved for reconsideration and requested to deconsolidate the energy efficiency docket on the grounds that Senate Bill 3, ratified by the General Assembly on August 2, 2007, includes G.S 62-133.8[1] which provides the Commission with express authority to consider and grant the relief requested by Duke's energy efficiency application, obviating the need to combine the energy efficiency docket with Duke's general rate case proceeding. In this motion, Duke also proposed a procedural schedule. On August 15, 2007, the Commission entered an order requesting comments on Duke's motion. Comments were filed on August 21, 2007, by CIGFUR III, CUCA, PSNC, Wal-Mart, the Public Staff and the Attorney General. On August 29, 2007, Duke, the Public Staff and the Attorney General filed reply comments.

On August 31, 2007, the Commission issued an order bifurcating this docket from Duke's pending general rate case investigation. The Commission concluded that Senate Bill 3, signed by the Governor August 20, 2007, authorized the Commission to hear the energy efficiency docket separate from general rate case proceedings, and that Duke's save-a-watt application should not be heard and decided until after the Commission completed its rulemaking to implement Senate Bill 3. On February 29, 2008, the Commission issued its Order Adopting Final Rules in Docket No. E-100, Sub 113 adopting new rules and amendments to implement Senate Bill 3; that same day the Commission also issued its Order Scheduling Hearing in this docket.

On March 11, 2008, the Alliance to Save Energy, the American Council for an Energy-Efficient Economy, and the Energy Future Coalition filed notice of their agreement with Duke to

[1] Renumbered G.S. 62-133.9 at the direction of the Revisor of Statutes.

support Duke's save-a-watt plan. These groups asked the Commission to include the first four elements of this agreement[1] in its ruling on this docket.

On April 4, 2008, Duke filed the direct testimony and exhibits of James E. Rogers, Chairman, President and Chief Executive Officer of Duke Energy Corporation (Duke Energy); Ellen T. Ruff, President of Duke; Judah Rose, Managing Director of ICF International; Jane Sadowsky, Senior Managing Director of Evercore Partners; Charles J. Cicchetti, co-founder and member in Pacific Economic Group, L.L.C.; Theodore E. Schultz, Vice President – Energy Efficiency, Duke Energy; Janice D. Hager, Managing Director of Integrated Resource Planning and Environmental Strategy, Duke; Richard G. Stevie, Managing Director of Customer Market Analytics for Duke Energy Shared Services, Inc.; Nick Hall, President and owner of TecMarket Works; Stephen M. Farmer, an independent contractor who provides rate and regulatory consulting services; and J. Danny Wiles, Vice President – Franchised Electric & Gas Accounting, Duke.

Duke filed an Agreement and Stipulation of Settlement with PSNC (PSNC Settlement Agreement) on June 24, 2008. An Agreement and Stipulation of Settlement between Duke and Piedmont (Piedmont Settlement Agreement) was filed on June 26, 2008.

The Public Interest Intervenors filed the direct testimony and exhibits of Roger D. Colton on June 24, 2008. On or about June 26, 2008, ED, NRDC, SACE and SELC (collectively, the Environmental Intervenors) filed the direct testimony and exhibits of Donald Gilligan, Brian M. Henderson and J. Richard Hornby; Air Products filed the direct testimony of James Butz; CIGFUR III filed the direct testimony and exhibits of Nicholas Phillips, Jr.; Wal-Mart filed the direct testimony and exhibits of James T. Selecky; CUCA filed the direct testimony of Kevin W. O'Donnell; and the Public Staff filed the direct testimony and exhibits of Jack Floyd, Michael C. Maness and Richard F. Spellman. NC WARN filed the direct testimony and exhibit of John O. Blackburn on June 27, 2008.

On July 21, 2008, Duke filed the rebuttal testimony and exhibits of Richard A. Morgan, President of the consulting firm Morgan Marketing Partners, and witnesses Cicchetti, Stevie, Rose, Hager, Wiles, Farmer and Schultz. The case came on for hearing as ordered on July 28, 2008. On August 1, 2008, the Public Staff filed two late-filed exhibits requested by the Commission regarding data on the top twenty electric energy efficiency utilities in the United States for the years 2004 and 2006. On August 7, 2008, the Attorney General filed Attorney General's Office Stevie Cross-Examination Exhibit No. 3, a reproduction of the information placed on the blackboard by the Attorney General's counsel and used during the cross-examination of Duke witness Stevie, which was requested by the Commission. On

[1] (1) Identify and pursue every cost-effective energy efficiency program. Duke will not impose any predetermined cap on Duke's total energy efficiency investment.

(2) An overall energy efficiency target for save-a-watt to achieve on-going annual electricity savings of at least 1% of its 2009 retail sales by 2015 (i.e., 1% savings in 2015, an additional 1% to total 2% in 2016, etc.), with savings each year over the 2009-2014 period ramping up to this 1% per year target.

(3) The use of accepted best practices in program evaluation, measurement and verification (EM&V). Duke is committed to allocate 5% of energy efficiency expenditures to EM&V.

(4) Make evaluation results available to all interested parties, to establish a broad-based peer review and advisory process, and to use evaluation results as feedback to continuously improve Duke's programs.

August 13, 2008, Duke filed the supplemental testimony and exhibits of witness Schultz in response to questions by the Commission during the hearing; the Public Staff filed the affidavit of witness Maness in response to this supplemental testimony on August 25, 2008. Duke filed one late-filed exhibit on August 18, 2008, and two more on August 27, 2008.

The parties submitted proposed orders and/or briefs on October 7, 2008. Proposed orders were submitted by Duke, the Public Staff, and the Public Interest Intervenors. Briefs were filed by Duke, the Public Interest Intervenors, the Environmental Intervenors, CUCA, NC WARN, the Attorney General, and jointly by CIGFUR III and Air Products.

On February 26, 2009, the Commission issued its Order Resolving Certain Issues, Requesting Information on Unsettled Matters, and Allowing Proposed Rider to Become Effective Subject to Refund in this docket (February 26, 2009 Order). Also on February 26, 2009, an errata order was issued replacing the supplemental information section of the February 26, 2009 Order beginning on page 60 and ending on page 63. On March 20, 2009, Air Products petitioned the Commission to reconsider the February 26, 2009 Order. On March 31, 2009, Duke filed the supplemental information requested in the February 26, 2009 Order and errata order.

The February 26, 2009 Order required Duke to work with the Public Staff to prepare a Notice to Customers giving notice of its proposed Rider EE. Duke and the Public Staff developed a Notice to Customers, which Duke filed on May 1, 2009. Duke filed Revised Tariffs and Riders on May 7, 2009. On May 8, 2009, the Commission approved the Revised Tariffs and Riders and the Notice to Customers and required Duke to publish the Notice.

On May 22, 2009, the Public Interest Intervenors filed comments regarding the supplemental information Duke filed in response to the February 26, 2009 Order. NC WARN filed comments on May 26, 2009. On June 12, 2009, the Public Staff and CUCA filed comments.

Also on June 12, 2009, Duke, the Environmental Intervenors and the Public Staff (collectively, the Stipulating Parties) filed an Agreement and Joint Stipulation of Settlement (Settlement Agreement or Agreement). On June 19, 2009, the Public Staff filed the settlement testimony of James S. McLawhorn; the Environmental Intervenors filed the settlement testimony and exhibits of John D. Wilson; and Duke filed the settlement testimony and exhibits of witnesses Wiles, Schultz, and Farmer.

On June 18, 2009, the Commission issued an order requiring both Duke and the Public Staff to file (a) Modified Internal Rate of Return (MIRR) analyses consistent with the Settlement Agreement, given their respective positions on the appropriate inputs to the MIRR calculations, and (b) testimony regarding the outstanding issue between the Stipulating Parties of the appropriate jurisdictional allocation method to use in determining the North Carolina retail Demand-Side Management/Energy Efficiency (DSM/EE) Rider.[1] The June 18, 2009 Order also scheduled a hearing on August 12, 2009, to consider the Settlement Agreement filed by the

[1] In this same order, the Commission decided to hold in abeyance any further consideration of the supplemental information filed by Duke on March 31, 2009.

Stipulating Parties. In accordance with this order, on June 26, 2009, Duke filed the MIRR testimony and exhibit of Raiford L. Smith, the Director of Strategy and Collaboration for Duke Energy Business Services, LLC. On July 2, 2009, the Public Staff filed the supplemental testimony and exhibits of witness Maness. Also on July 2, 2009, the Commission issued an Order rescheduling the hearing, to consider the Settlement Agreement, to August 19, 2009.

On July 22, 2009, Air Products moved for the Commission to enter an order requesting comments on its petition to reconsider the February 26, 2009 Order, and if deemed necessary, scheduling an oral argument. On August 17, 2009, the Commission issued an order denying Air Products' petition to reconsider and its motion.

On July 27, 2009, the Public Interest Intervenors filed the supplemental testimony of witness Colton. On August 10, 2009, Duke filed the rebuttal testimony of witness Smith in response.

On July 30, 2009, the Commission entered a pre-hearing order requesting verified information from the Stipulating Parties, which Duke responded to on August 10, 2009. The Commission entered a second pre-hearing order requesting verified information from the Environmental Intervenors and the Public Staff on August 14, 2009, which both responded to on August 18, 2009.

The case came on for hearing as ordered on August 19, 2009. On August 28, 2009, Duke filed late-filed exhibits in response to questions posed by the Commission during the hearing. The Public Staff filed late-filed exhibits on September 1, 2009. The deadline for parties to file proposed orders and/or briefs was October 7, 2009.

On December 14, 2009, the Commission entered a Notice of Decision in this docket. The Notice of Decision stated that the Commission was approving the Settlement Agreement subject to certain specified modifications and decisions on contested issues and that the Commission would thereafter enter an Order Approving Agreement and Joint Stipulation of Settlement Subject to Certain Commission-Required Modifications and Decisions on Contested Issues. Duke was authorized to submit revised save-a-watt rates and tariffs for implementation for service rendered on and after January 1, 2010. Duke was requested to consult with the Public Staff prior to filing any revised tariffs and a proposed customer notice to ensure that the Public Staff was in agreement therewith.

On December 23, 2009, the Commission approved Duke's proposed customer notice and on December 28, 2009, the Commission approved Duke's proposed compliance rate schedules.

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

ELECTRIC – MISCELLANEOUS

FINDINGS OF FACT

1. Duke 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 and the Settlement Agreement pursuant to the Public Utilities Act. A utility must submit cost-effective DSM and EE options that require incentives to the Commission for approval and 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 Duke is seeking in this docket.

3. On May 7, 2007, Duke filed its application for approval of the save-a-watt approach (the original save-a-watt proposal), EE rider (Rider EE) and portfolio of EE and DSM programs (collectively, the EE plan) with the Commission. After the filing of testimony and exhibits and a fully litigated hearing, the Commission issued the February 26, 2009 Order, in which it resolved certain issues, requested information on unsettled matters, and allowed the proposed Rider EE to become effective subject to refund.

4. On June 12, 2009, the Stipulating Parties filed the Settlement Agreement, which resolves all issues between the Stipulating Parties associated with Docket No. E-7, Sub 831, including Duke's EE plan and Duke's proposed compensation model; except for certain cost allocation issues, which the Stipulating Parties requested that the Commission decide in this proceeding, and the issue of the interest rate to be applied to refunds to customers resulting from overcollection, which the Stipulating Parties requested that the Commission decide in the first annual true-up proceeding in which an overcollection occurs.

5. The Settlement Agreement proposed a "Modified Save-a-Watt Approach" whereby Duke would be compensated based on predetermined percentages of Duke's capacity- and energy-related "avoided costs," which would represent an estimate of the cost of supplying electricity. These percentages include 75% of avoided capacity costs for DSM programs, and 50% of the net present value (NPV) of the avoided energy costs plus 50% of the NPV of avoided capacity costs for EE programs. The Commission concludes that the level of avoided cost recovery proposed in the Settlement Agreement is reasonable and in the public interest.

6. The modified save-a-watt approach has a term of four years, and it is a pilot program.

7. The Settlement Agreement provides for increased energy savings targets as compared to the original save-a-watt proposal.

8. The Settlement Agreement includes a performance target of avoided cost savings based on projected EE and DSM results. Duke's avoided cost target, based on 100%

participation, is $754 million[1] (nominal system dollars) and is tied to target capacity and cumulative energy savings for the life of the EE measures. The Commission concludes that Duke's performance targets under the Settlement Agreement are appropriate.

9. The earnings to Duke that result from the incentive compensation will be capped at a percentage of incurred program costs not to exceed 15%. The specific percentage applied to program costs to determine the earnings cap will be based on the percentage of the target avoided cost savings actually achieved. The earnings cap based on Duke's performance helps ensure that customers receive fair value and that their rates remain reasonable.

10. The Settlement Agreement and supporting testimony provide for the separate recovery of 36 months of net lost revenues, as defined by Commission Rule R8-68, resulting from EE measures only. The Commission authorizes Duke to recover net lost revenues for 36 months for each installation of an EE measure during a given vintage year,[2] except that the 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.

11. The cumulative jurisdictional revenue requirement for the four-year term of the Settlement Agreement is significantly less under the Settlement Agreement than under the original save-a-watt proposal. The rate impacts under the Agreement are reasonable in light of Duke's increased energy and capacity savings targets, and Duke's revised Rider EE reflecting these rate impacts is in the public interest and should be approved.

12. After the conclusion of the four-year term of the Settlement Agreement, actual measured and verified avoided cost savings will be compared to the target avoided cost savings in a final true-up proceeding. The true-up process provides a reasonable means of ensuring that Duke does not collect revenues for its DSM and EE programs in excess of what is allowed under the Agreement.

13. The costs of Duke's DSM and EE programs should be allocated to the North and South Carolina retail jurisdictions, and such costs should be recovered from only the class or classes of retail customers to which the programs are targeted. No costs of any approved DSM or EE program should be allocated to the wholesale jurisdiction. The reduced energy consumption resulting from the implementation of EE measures, or EE Renewable Energy Certificates (RECs), thus paid for by Duke's retail customers should be used solely for Duke's Renewable Energy Portfolio Standard (REPS) compliance obligation.

14. The Settlement Agreement provides for the creation of a Regional Efficiency Advisory Group (the Advisory Group) to review the measurement and verification process,

[1] As shown in Duke's Late-Filed Exhibits, the avoided cost target for North Carolina only is $547 million.

[2] A vintage year is the twelve month period in which a specific DSM or EE measure is installed for an individual participant or a group of participants.

collaborate on new program ideas, and review changes to existing programs. The Commission concludes that the establishment of this Advisory Group is in the public interest.

15. Pursuant to Commission Rule R8-27(a)(2), the Commission authorizes Duke, for North Carolina jurisdictional regulatory accounting purposes, to utilize Account 182.3 – Other Regulatory Assets to record the difference between the level of revenues estimated to be ultimately recoverable under the Settlement Agreement and the level of revenues then currently billed under Rider EE when it is probable that such ultimately recoverable revenues will be greater than the currently billed revenues, and Account 254 – Other Regulatory Liabilities to record the difference between the level of revenues then currently billed customers and the level of revenues that is estimated to be ultimately recoverable when it is probable that such currently billed revenues are in excess of the revenues ultimately recoverable.

16. The methods and criteria to be utilized in determining the interim and ultimate rates charged for the term of the Settlement Agreement, including the true-up processes discussed herein, are sufficient to support deferral accounting for North Carolina jurisdictional regulatory purposes.

17. With regard to save-a-watt, Duke should be required (1) to include all actual program revenues (estimated, if not known) and only actual program costs (estimated, if not known) for purposes of calculating and presenting its regulated earnings to the Commission for NCUC ES-1 purposes; (2) to provide supplementary schedules setting forth the Company's jurisdictional earnings excluding the effects of EE and DSM programs; and (3) to provide schedules separately stating the earnings impact of its DSM and EE programs on a combined basis as well as on a stand-alone, program-class basis, that is, with earnings from DSM programs, collectively, and earnings from EE programs, collectively, shown separately. Detailed calculations of the foregoing should also be provided. Such schedules and/or calculations should show, at a minimum, actual revenues; expenses; taxes; operating income; investment base, including major components where applicable; and applicable capitalization ratios and cost rates, including overall rate of return and return on common equity. Net lost revenues realized (estimated, if not known) for each reporting period should be clearly disclosed as supplemental information.

18. The Commission concludes that the Public Interest Intervenors have not presented any new evidence justifying revision of Duke's EE and DSM programs that were approved in the February 26, 2009 Order. The Public Interest Intervenors' request for rejection and/or modification of the Settlement Agreement should be denied.

19. The Settlement Agreement is reasonable and appropriate and in the public interest. The incentives proposed by the Stipulating Parties, including net lost revenues and the modified save-a-watt approach, are reasonable and appropriate and in the public interest.

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, Settlement Agreement, pleadings, testimony and exhibits in this docket, and the statutes, case law, and rules governing the authority and jurisdiction of this Commission. These findings are informational, procedural, and jurisdictional in nature.

Prior to the passage of Senate Bill 3, the Commission's authority to authorize cost recovery pursuant to a rider for DSM and EE programs was unclear. The Commission requested comments on its authority to consider Duke's application and eventually consolidated Docket No. E-7, Sub 831 with Duke's general rate case proceeding. Although the Commission acknowledged that the pending Senate Bill 3 would expressly address whether the Commission possessed this authority, because enactment was possibly several weeks away, the Commission consolidated the dockets, reserving the right to reconsider its decision. Duke requested reconsideration of consolidation shortly after the General Assembly ratified Senate Bill 3. Senate Bill 3 became law soon thereafter, and the Commission accordingly granted Duke's request and bifurcated Docket No. E-7, Sub 831 from Duke's general rate case.

Among other things, Senate Bill 3 contains the new G.S. 62-133.9, which concerns cost recovery for DSM and EE programs. This specific statute 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. G.S. 62-133.9(c) specifically provides that utilities shall submit DSM and EE programs that require incentives to the Commission for approval.

Commission Rule R8-68 establishes guidelines for the application of G.S. 62-133.9. Under this Rule, a utility must obtain Commission approval before implementing any new or modified DSM or EE measure. Rule R8-68 sets forth detailed filing requirements and outlines what the Commission may consider in deciding whether to approve a new measure or program. The Rule also provides 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 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. The Rule defines a 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." Rule R8-69(a)(2). 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 EE and DSM programs as well as appropriate utility incentives, including specifically. "[a]ppropriate rewards based on capitalization of a percentage of avoided costs achieved by demand-side management and energy efficiency measures." The incentives Duke seeks under the modified save-a-watt approach are based upon paying Duke a percentage of the avoided capacity costs achieved by DSM measures, and a separate percentage of the NPV of avoided capacity costs and avoided energy costs achieved by EE measures. In addition, the Settlement Agreement provides for a limited period of recovery of Duke'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 Duke is seeking in this docket.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

The evidence in support of this finding can be found in the application, the proposed order and brief Duke submitted on October 7, 2008, and the Order issued by the Commission on February 26, 2009, in this docket.

On May 7, 2007, Duke filed its application in this docket proposing its EE plan. By this filing, Duke requested approval of its original save-a-watt proposal, a portfolio of EE programs, and Rider EE to compensate and reward it for verified DSM and EE results and to recover the amortization of, and a return on, 90% of the costs avoided by the EE plan. More specifically, Duke requested that the Commission, after hearing, issue an order approving (1) the implementation of the original save-a-watt proposal; (2) the portfolio of proposed EE programs; (3) the implementation of the proposed Rider EE, including the proposed initial charges for customers; (4) the deferral of program costs and amortization of such costs over the life of the applicable program, with an acknowledgement that the revenues established in Rider EE based on avoided costs specifically include the recovery of incurred program costs; (5) the closing of designated existing programs; and (6) the proposed manner of accounting for the impacts of the original save-a-watt proposal in Duke's Quarterly Surveillance Reports (NCUC Form ES-1 Reports) to the Commission.

The Commission held hearings on Duke's application in July and August 2008.

On February 26, 2009, the Commission entered an Order granting Duke's request for approval of its portfolio of proposed EE programs. The Commission also approved Duke's DSM program Power Manager, and provided that current customers on Rider LC be given the option to discontinue participation before being transferred automatically to Power Manager. Similarly, the Commission approved the PowerShare DSM program, and provided that existing current customers on Rider IS and Rider SG be allowed to continue to participate in those programs at their current contract levels. The Commission granted Duke's request to close certain existing programs. In addition, Duke's proposed measurement and verification plan was approved by the Commission, as were its settlement agreements with Piedmont and PSNC. The Commission also ordered that certain types of program changes would require Commission approval. The Commission rejected Duke's proposed accounting and reporting procedures, and specified a different approach in the February 26, 2009 Order. Finally, the Commission allowed Duke's proposed Rider EE to become effective subject to refund.

The Commission determined that the record was not adequate to allow it to reach a decision regarding certain issues concerning the appropriateness of Duke's save-a-watt, avoided cost-based compensation mechanism. Accordingly, the Commission required Duke to provide certain supplemental information and data; and deferred ruling on the proposed compensation mechanism. Duke filed this supplemental information, and several intervenors submitted their comments thereto, but the Commission decided to hold in abeyance its consideration of this supplemental information pending consideration of the Settlement Agreement.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The evidence in support of this finding can be found in the Settlement Agreement and the testimony of Duke witness Stephen Farmer.

On June 12, 2009, the Stipulating Parties filed the Settlement Agreement, which resolved all issues between the Stipulating Parties associated with Docket No. E-7, Sub 831, including Duke's proposed compensation model, except for certain cost allocation issues which the Stipulating Parties requested that the Commission decide in this proceeding and the issue of the interest rate to be applied to refunds to customers resulting from overcollection, which the Stipulating Parties requested that the Commission decide in the first annual true-up proceeding in which an overcollection occurs.

The Settlement Agreement retains many features of Duke's original save-a-watt proposal. For example, the Agreement provides for compensation to Duke for successful implementation of DSM and EE programs on the basis of a discount to the "avoided costs" of a power plant rather than on the basis of what Duke spends on DSM and EE programs. This compensation is based upon actual DSM and EE savings achieved, measured and verified by an independent third party as described in the testimony of Duke witnesses Dr. Richard D. Stevie and Nick Hall, filed in this docket on April 4, 2008.[1] As in the original save-a-watt proposal, Duke bears the risk, based upon its actual performance, for recovery of its DSM and EE program costs, as well as any management incentive.

The Settlement Agreement incorporates a number of provisions that are important to the Environmental Intervenors. For example, the Agreement contains performance targets pursuant to which Duke is eligible to receive a higher level of incentive based upon its performance in achieving actual demand and energy reductions that result in bill savings for customers, as well as environmental benefits. The performance targets reflect a significant increase in energy savings when compared to the original save-a-watt proposal. To protect consumers and encourage strong performance, Duke's earnings opportunity is tied to Duke's performance in achieving its targets, and is capped at preset percentages of return on investment on program costs, ranging from 5% to 15%.

Along with certain of the provisions listed above, the Settlement Agreement also incorporates additional provisions that are important to Duke, the Public Staff, and the Environmental Intervenors. First, Duke proposed the modified save-a-watt model as a four year limited term pilot, which limits the exposure of the parties to unintended consequences that can occur with a new regulatory approach. Second, Duke's revenues recovered on the basis of percentages of avoided costs are limited to the amount necessary to produce an after-tax return

[1] The Commission approved Duke's proposed Measurement & Verification Plan in Order Resolving Certain Issues, Requesting Information on Unsettled Matters, and Allowing Proposed Rider to Become Effective Subject to Refund, at p. 64 (February 26, 2009).

on program costs between 5% and 15%, depending on Duke's success in reaching the target aggregate DSM and EE avoided cost savings level. Third, the amount of net lost revenues that Duke may recover is limited to those incurred within 36 months of implementation of a particular measure. The Settlement Agreement and supporting testimony provide for the separate recovery of these net lost revenues resulting from EE programs only.[1] The Settlement Agreement defines net lost revenues consistently with Commission Rule R8-68, which results in greater transparency. Fourth, unlike the original save-a-watt proposal, which tied revenue recovery for DSM and EE programs to variable supply-side costs, the Agreement locks in the per megawatt hour (MWh) and per MW-year avoided costs. Finally, the Settlement Agreement provides for the return, with interest, to ratepayers of any revenues collected in excess of what is allowed under the Settlement Agreement. Under the Settlement Agreement, any overcollection will be returned to the customers with interest, at an interest rate to be determined by the Commission in the first true-up proceeding in which an overcollection occurs.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5 AND 6

The evidence in support of these findings is found in the Settlement Agreement, as well as the testimony and exhibits of Public Staff witness McLawhorn and Duke witnesses Schultz and Farmer.

Theodore E. Schultz, Vice President of EE for Duke Energy Business Services, testified that Duke initially proposed that revenue requirements reflect 90% of the avoided capacity and energy costs produced by both DSM and EE programs – as compensation for program costs, lost revenues, and a management incentive. He explained that three primary changes were made in the Settlement Agreement to the avoided cost percentage contained in the original save-a-watt proposal. First, witness Schultz stated that separate avoided cost percentages were developed for DSM and EE programs to ensure that Duke would be indifferent to implementation of either kind of program relative to the portfolio's overall profitability. Second, the recovery of lost revenues was carved out of the avoided cost compensation and treated as a direct recovery cost. And third, the percentages were lowered from 90% to 75% of the avoided capacity costs for DSM achievements and to 50% of the NPV of avoided lifetime capacity and energy costs for EE programs. Witness Schultz explained why Duke believed it was appropriate to capture the NPV of EE savings in the year in which Duke spends money on the EE measure:

> [W]e spend the money up front on energy efficiency. All the costs are actually incurred in the first year. There's a stream of [future] benefits, and it's appropriate from our point of view to bring those benefits back to present value . . . in the year in which the program was installed.

Duke does not use NPV for its DSM percentage because, according to witness Schultz, DSM programs do not create future benefits:

[1] The June 19, 2009 testimony of Duke witness Farmer and Duke's August 10, 2009 Responses to the Commission's Pre-Hearing Order Requiring Verified Information clarify that recovery of net lost revenues under the Settlement Agreement is limited to EE programs only.

> Demand-side management programs are a benefit for the year in which they occur. So, in other words, they're equivalent to a peaking station. So every year you can look at those and they're either there or they're not. And if they're there, they have benefit for the year that they're there.[1]

Chairman Finley asked witness Schultz why Duke uses a higher avoided cost recovery percentage for DSM programs than for EE programs. Witness Schultz explained that the different percentages were designed to put EE and DSM on a "level playing field" so that they both earn a similar return. He testified that "if you look at the 75 percent applied to the portfolio for demand-side management resources, you're going to get a [maximum] return per the Settlement Agreement . . . of 15% after tax for program cost." He went on to say that while EE appears lower at 50%, "[y]ou've got to remember it's the present value of all those benefits coming back and lost margins are separated out. So lost margins occur with energy efficiency programs. They're treated separately, which would lower the avoided cost percentage. And then that 50 percent again will return about a 15 percent after tax return on the program cost."

Witness Schultz testified that avoided capacity costs will be based on Duke's filed avoided cost rate, as Duke initially proposed, with one modification. He explained that instead of updating the avoided costs with the bi-annual filed avoided cost rates, the avoided capacity costs under the Settlement Agreement will remain fixed using the 2007 approved avoided costs in Docket No. E-100, Sub 106. James S. McLawhorn, Director of the Electric Division of the Public Staff, explained that in the original save-a-watt proposal, Duke proposed to tie its revenue recovery for implementing DSM and EE programs to its avoided supply-side costs, which can vary over time. The Public Staff was concerned that, if avoided supply-side costs increased from one year to the next, ratepayers would pay for that increase, even if they were not receiving any additional energy or demand reduction savings. Witness McLawhorn testified that the Settlement Agreement shields ratepayers from this risk by "locking in" the avoided cost rate for the term of the Agreement.

Witness Schultz testified that the calculation of the avoided energy costs will be the same as initially proposed by Duke and will be based on the avoided energy costs per Duke's Integrated Resource Plan. He added that the avoided cost rates will not be otherwise updated during the term of the Settlement Agreement unless the filed biennial avoided capacity and energy cost rates change by more than 25%.

Witness McLawhorn testified that the Public Staff believed that Duke's initial proposal to recover 90% of avoided costs achieved by its proposed EE and DSM programs would have resulted in excessive earnings by Duke and insufficient savings on energy by ratepayers. He explained that the Settlement Agreement addresses these concerns by providing that Duke's revenues are now to be recovered on the basis of separate percentages of avoided costs for DSM and EE programs. Witness McLawhorn noted that the recovery of these percentages of avoided costs is intended by Duke to cover its costs for adopting and implementing DSM and EE programs, along with providing a financial incentive for doing so.

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[1] In Comments filed in this docket on June 12, 2009, the Public Staff indicated that it disagreed with Duke's position that DSM programs do not create future benefits beyond one year. This disagreement, however, did not prevent the Public Staff from entering into the Settlement Agreement.

Witness McLawhorn testified that the Settlement Agreement also addresses the Public Staff's concerns by limiting the cost recovery period for the modified save-a-watt approach. Specifically, the Settlement Agreement has a term of four years, and it is a pilot program. Witness McLawhorn testified that, at the conclusion of this four-year period, actual measured and verified avoided cost savings will be compared to the target avoided cost savings in a final true-up proceeding.

The Settlement Agreement preserves Duke's concept that compensation for implementation of EE and DSM programs should be based on a discount to the avoided costs of a power plant, but modifies the compensation mechanism to provide for a more reasonable level of avoided cost recovery. The Stipulating Parties have demonstrated that the percentages of avoided costs under the modified save-a-watt approach provide an appropriate incentive to Duke without resulting in excessive earnings. The Commission concludes that the levels of avoided cost recovery under the Settlement Agreement are in the public interest.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 7 THROUGH 9

The evidence in support of these findings can be found in the Settlement Agreement, as well as the testimony and exhibits of Environmental Intervenors witness Wilson, Public Staff witness McLawhorn, and Duke witness Schultz.

Duke witness Schultz provided testimony regarding the Settlement Agreement's performance targets and earnings caps. He explained that under the Settlement Agreement, Duke is eligible to receive a higher level of incentive based on how well it performs. Specifically, Duke's earnings opportunity is capped and is tied to the percentage of the target energy and capacity savings achieved. The Settlement Agreement provides for an energy savings target for each vintage year. This energy savings target is then converted to a sum of monetary savings that reflects the cost of energy and capacity avoided as a result of the EE measures, over the life of each measure. The resulting avoided cost savings target is determined by multiplying the savings by year by the full avoided costs, which include generation capacity, fuel, and fixed and variable operations and maintenance savings. The target amount of avoided cost savings dollars for the DSM component will be calculated based on an assumed amount of capacity avoided through DSM programs and the avoided costs in effect at the time the Settlement Agreement is approved by the Commission.

Duke's avoided cost target is $754 million (nominal system dollars) based on programs implemented during the four-year term of the Agreement and is tied to the following target MW and cumulative MWh system savings: 234,132 MWh and 368 MW in Year 1; 490,634 MWh and 548 MW in Year 2; 872,548 MWh and 736 MW in Year 3; 1,439,742 MWh and 844 MW in Year 4; and 6,833,078 MWh and 259 MW beyond Year 4.

As witnesses McLawhorn, Schultz and Wilson testified, the Settlement Agreement provides for increased energy savings targets when compared to the original save-a-watt proposal. Witness Wilson testified that the energy savings targets contained in the Settlement Agreement represent a commitment by Duke to ramp up its EE offerings in the Carolinas to levels that will make Duke a leader in the industry. For example, Duke's target incremental reduction in annual energy use by year 4 under the Agreement is equal to 0.75% of its forecasted sales for that year – 250% of the year 4 target in the original save-a-watt proposal. In addition, witnesses Wilson and McLawhorn testified that the Settlement Agreement provides that no more than 35% of the target may be met by DSM programs, providing an emphasis on EE programs that the original save-a-watt model lacked.

Further, witness McLawhorn testified that measures implemented in each vintage year of this Settlement Agreement are expected to continue to operate and produce energy savings throughout the four-year term. Witness Wilson explained that, if Duke meets its savings targets, the cumulative reduction in annual energy consumption by year 4 will be almost 2% of annual sales in that year and over 8% within 10 years.

Based on these target portfolio savings, the Settlement Agreement contains tiered earnings caps based upon varying levels of performance. Duke's revenues recovered on the basis of percentages of avoided costs are limited to the amount necessary to produce an after-tax return on program costs between 5% and 15% depending on its success in reaching a target aggregate DSM and EE avoided cost savings level.

Specifically, if Duke achieves 90% or greater of its avoided cost target, its earnings will be capped at a 15% return on program costs; if Duke achieves 80% to 89% of its avoided cost target, its earnings will be capped at a 12% return on program costs; if Duke achieves 60% to 79% of its avoided cost target, its earnings will be capped at a 9% return on program costs; and if Duke achieves less than 60% of its avoided cost target, its maximum earnings opportunity will be a 5% return on program costs. Witness Schultz testified that program costs will include marketing and advertising expenses, incentives paid to customers, and the costs of impact evaluation studies. The return on program costs will be simply a calculation of the after tax percent return on investment in program costs on a net present value basis.

The Stipulating Parties have demonstrated that the Settlement Agreement provides for a significant increase in the amount of energy and capacity savings Duke aims to achieve. Any incentive earned by Duke will depend upon Duke's ability to actually achieve these target savings on behalf of customers. The Commission concludes that these performance targets are appropriate and that the earning caps tied to these targets help ensure that customers receive fair value and that their rates remain reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The evidence in support of this finding is found in the Settlement Agreement, as well as the testimony and exhibits of Public Staff witnesses Maness and McLawhorn, Duke witness Farmer, and Environmental Intervenors witness Wilson.

The Settlement Agreement provides for the separate recovery of net lost revenues resulting from EE, but not DSM, measures. Net lost revenues are also net of any increases resulting from any activity by Duke'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. The amount of net lost revenues that Duke may recover is limited to those incurred within 36 months of implementation of any particular measure.

Public Staff witness Maness confirmed that recovery of net lost revenues act to make a company whole, and act to replace revenues that Duke has lost from enacting an EE program. He added, "I think another way of saying that is that without that net lost revenue compensation there would be a disincentive to proceed with those types of programs."

Duke witness Farmer testified that the original save-a-watt proposal did not call for the explicit recovery of net lost revenues, but rather the recovery of net lost revenues was embedded in the revenue requirement calculations that were based on 90% of estimated avoided capacity and energy costs. As such, it was not readily evident what portion of the revenues were compensating Duke for incurred DSM and EE program costs, net lost revenues, and additional incentives.

Witness McLawhorn testified that under the Settlement Agreement net lost revenues are now subject to measurement and verification and are recovered separately from program costs and incentives.

Witness Schultz testified that recovery of lost revenues separate from the percentage of avoided cost payment will result in greater transparency.

Environmental Intervenors witness Wilson testified that a mechanism to recover lost revenues is important because it mitigates the disincentive to pursue EE created by the existing electric rate structure in North Carolina. According to witness Wilson, limiting this mechanism to three years ensures that Duke does have a strong incentive to adjust its supply-side resources (power plants and contracts) to reflect reduced demand. Witness Wilson further testified that limiting lost revenue recovery to 36 months will help ensure that customers receive fair value and that their rates remain reasonable.

With regard to the limited period of time for recovery of net lost revenues, witness McLawhorn testified that the Settlement Agreement recognizes the Public Staff's view that revenues that are "lost" due to an EE program do not continue in perpetuity, but are offset in time by revenue gains, resulting, for example, from customer growth or other increases in demand. He testified that the Public Staff believes that 36 months is a reasonable amount of time for the recovery of net lost revenues and noted that this limited time period is similar to one contained in the Agreement and Stipulation of Partial Settlement, filed by the Public Staff, PEC, and Wal-Mart, in Docket No. E-2, Sub 931, and approved by the Commission by Order dated June 15, 2009.

Witness Farmer explained that the recovery of net lost revenues applicable to EE programs for vintage years three and four will extend two-years beyond the initial four-year cost recovery period, assuming such recovery does not terminate or is not reduced as a result of approval of a decoupling or alternative recovery mechanism or an order in a general rate case proceeding that provides for the recovery of net lost revenues. As witness Maness testified, "[W]hen you have vintage year three and four, installations of measures that caused net lost revenues, the 36 months for those installations will extend beyond year four and, therefore, there are net lost revenues to be recovered in years five and six."

Witness Farmer testified that the estimated amount of net lost revenues to be collected from North Carolina customers totals $151 million at 85% achievement. He clarified that the recovery of net lost revenues will be subject to adjustment (either up or down) based on the level of verified kW and kWh reductions actually realized. For example, at a savings level that equals 100% of target achievement the recovery of net lost revenues would total approximately $178 million.

Witness Farmer provided testimony explaining how Duke will calculate net lost revenues under the Settlement Agreement. He explained that the calculation of net lost revenues (sometimes referred to as lost margins) was estimated by multiplying the portion of Duke's tariff rates that represent the recovery of fixed costs by the estimated kW and kWh reductions applicable to EE programs. Duke calculated the portion of retail tariff rates representing the recovery of fixed costs by deducting the recovery of fuel costs from its tariff rates.

The calculation of net lost revenues does not apply to DSM programs. Witness Farmer testified that Duke is not seeking recovery of net lost revenues for DSM programs because the demand response essentially covers the cost of the program. In other words, if Duke spends a dollar on a DSM program, Duke in turn will not have to provide the amount of electricity needed at the peak period. Witness Farmer then clarified that there are some net lost revenues as peaks are reduced by DSM programs. In particular, if a customer lowers its demand, then the revenue from that customer will be lower. Notwithstanding the net lost revenues resulting from DSM programs, Duke has chosen not to ask for recovery of these net lost revenues.

In his brief, the Attorney General argued that the Settlement Agreement should be approved, with one exception. The exception being that the Agreement should be modified to require that all net lost revenues are to be included, in the manner proposed by the Attorney General, in calculating save-a-watt's maximum profit levels, including allowable earnings under the earnings cap. According to the Attorney General, if all net lost revenues are not so included, Duke's profits from save-a-watt would be excessive and, as such, would not produce reasonable consumer rates.

In support of his position, the Attorney General presented an example which he contended showed that, if Duke is allowed to recover estimated net lost revenues of $151 million,[1] the Company would realize an after-tax profit of 58% from save-a-watt.

While the Attorney General did not present a detailed calculation of his projected return of 58%, such return appears to have been calculated as shown in Attorney General's Maness Cross-Exam Exhibit No. 1, with one exception. The exception being that net lost revenues of $151 million appear to have been substituted for the estimated $165 million originally included in the aforesaid exhibit. Assuming that to be the case, and it certainly appears to be, the Attorney General, in effect, is arguing that net lost revenues should not be treated as a cost; but rather, as pre-tax operating income for purposes of determining save-a-watt's profitability. Such

[1] This amount is set forth in Exhibit B attached to the Settlement Agreement.

profitability, of course, is central, if not controlling, in determining the maximum level of save-a-watt revenues the Company is to be allowed to recover under the earnings cap.

As noted above, in their proposed order, the Stipulating Parties contended that reductions in energy use resulting from EE programs may impair the Company's ability to recover sufficient revenues to cover its fixed costs. According to the Stipulating Parties, the evidence shows that, in the near term, the reduction in electricity sales resulting from EE programs will result in net lost revenues, which present a financial disincentive to the Company to implement EE programs.

Accordingly, the Stipulating Parties opined that, to encourage implementation of approved EE programs, the Commission should authorize the Company to recover net lost revenues for 36 months for each installation of an EE measure during a given vintage year, except that the recovery of net lost revenues would 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. The Stipulating Parties further proposed that recovery of net lost revenues for vintage year installations not covered by the new rates should be allowed to continue, subject to the 36-month limitation.

For purposes of resolving this issue in this proceeding, the Commission is of the opinion, and so finds and concludes, that the greater weight should be placed on the evidence and arguments presented by the Stipulating Parties, as generally described above, as opposed to the evidence and arguments advanced by the Attorney General.

The Commission is of the foregoing opinion because, in its view, net lost revenues, when appropriately quantified and deemed recoverable as an incentive by the Commission, do not represent pre-tax profits but rather, in effect, represent a provision for the recovery of fixed costs, including cost of capital, which would otherwise go unrecovered.[1]

Clearly, to the extent that decreased sales resulting from EE programs are not offset by growth trends in customer count and per-customer usage or by new rates in a rate case or comparable proceeding set to recover those net lost revenues, absent a cost recovery mechanism such as the one at issue here, the Company would, as a matter of fact, actually incur a real economic loss; and that potential loss would, undoubtedly, serve as a financial disincentive to the Company to implement EE programs.

Therefore, for the foregoing reasons, and based upon the entire evidence of record, the Commission is of the opinion, and so finds and concludes, that the separate recovery of net lost revenues resulting from the Company's implementation of EE, but not DSM, measures as

[1] As a matter of fact, according to Company witness Farmer, ". . . net lost revenues was [sic] 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 energy efficiency programs." This should not, however, be interpreted or construed to mean that the Commission is in agreement with the methodology employed by witness Farmer in estimating fixed costs and/or net lost revenues for purposes of this proceeding, for that is clearly not the case. As discussed subsequently, net lost revenues should be net of all marginal costs, including energy-related and nonenergy-related costs, actually avoided.

contemplated by the Settlement Agreement and/or the Stipulating Parties' proposed order should be, and hereby is, approved. Further, the Commission is of the opinion that the specific language of this provision of the Agreement should be, and hereby is, modified to read as follows:[1] (Modifications are shown in a track changes format.)

G. Net Lost Revenues

1. Net lost revenues mean revenue losses, net of marginal costs avoided at the time of the lost kilowatt-hour sale(s), incurred by the Company's public utility operation as the result of a new ~~demand-side management or~~ energy efficiency measure. Net lost revenues shall also be net of any increases in revenues resulting from any activity by the Company's public utility operations that cause a customer to increase demand or energy consumption, whether or not that activity has been approved pursuant to R8-68. Programs or measures with the primary purpose of promoting general awareness and education of energy efficiency as well as research and development activities are ineligible for the recovery of net lost revenues. Pilot programs or measures are also ineligible for the recovery of net lost revenues, unless the Commission approves the Company's specific request that a pilot program or measure be eligible for the recovery of net lost revenues when the Company seeks approval of that pilot program or measure. Utility activities shall be closely monitored by the Company to determine if they are causing a customer to increase demand or consumption, and the Company shall identify and keep track of all of its activities that cause customers to increase demand or consumption, whether or not those activities are associated with demand-side management or energy efficiency programs, as provided in the Settlement Agreement, so that they may be evaluated by the parties and the Commission for possible confirmation as "found revenues." When authorized by Commission Rule R8-69, and unless the Commission determines otherwise in a G.S. 62-133.9 DSM/EE rider proceeding, net lost revenues shall be recovered for 36 months for each vintage year, except that the recovery of net lost revenues will end upon Commission approval of (1) an alternative recovery mechanism, or (2) 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.

The Commission concludes that the modifications set forth above are reasonable and should be adopted in this proceeding. They are largely, if not totally, consistent with and track certain provisions adopted by the Commission with respect to the DSM/EE cost recovery plan approved for Progress Energy. In addition, Duke and the Public Staff are hereby requested to work cooperatively to develop practices and procedures which will ensure, to the maximum

[1] To the extent that modifications set forth below have not been previously discussed, they have been excerpted from either the Public Staff's August 18, 2009 comments in response to the Commission's Second Pre-Hearing Order Requiring Verified Information, in the present docket, or from the Commission's Order Approving Agreement and Stipulation of Partial Settlement, Subject to Certain Commission-Required Modifications, in Docket No. E-2, Sub 931, in the matter of Application by Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc., for Approval of Demand-Side Management and Energy Efficiency Cost Recovery Rider Pursuant to G.S. 62-133.9 and Commission Rule R8-69.

extent possible, that the Company is able to identify and keep track of all its activities that cause customers to increase demand or consumption, whether or not those activities are associated with demand-side management or energy efficiency programs, so that they may be evaluated by the parties and the Commission for possible confirmation as "found revenues."

There is one remaining related matter which needs to be discussed. NC WARN and the Public Interest Intervenors are of the opinion that the Company should be required to quantify the utility-related nonenergy benefits associated with save-a-watt's energy efficiency programs and recognize those cost savings in the save-a-watt cost recovery process. The Commission agrees.

Under the Settlement Agreement, and as modified and adopted by the Commission herein, the definition of net lost revenues provides, in pertinent part, as follows:

> Net lost revenues mean revenue losses, net of marginal costs avoided at the time of the lost kilowatt-hour sale(s) . . . .

Absent evidence or argument to the contrary, it would appear reasonable to conclude that the instant language is intended to mean that net lost revenues are to be net of <u>all</u> marginal costs avoided at the time of the lost kilowatt-hour sale(s). However, the Stipulating Parties' proposed order contains certain language, which, if taken literally, might lead one to conclude that the Stipulating Parties intended that net lost revenues be net of energy-related avoided cost only. The language in question is as follows:

> Witness Farmer provided testimony explaining how the Company <u>will calculate net lost revenues under the Settlement Agreement</u>. He explained that the calculation of net lost revenues (sometimes referred to as lost margins) was estimated by multiplying the portion of the Company's tariff rates that represent [sic] the recovery of fixed costs by the estimated kW and kWh reductions applicable to EE programs. The Company calculated the portion of retail tariff rates representing the recovery of fixed costs by deducting the recovery of fuel costs from its tariff rates. (Citations omitted.) (Emphasis added.)

Thus, based upon the foregoing, it might be concluded that the Stipulating Parties intended that net lost revenues be net of only fuel or energy-related avoided costs;[1] if so, such a provision would allow the Company, arguably, to recover nonenergy-related costs that it had, in reality, actually avoided. Such a result would, of course, be inappropriate. Consequently, out of an abundance of caution, the Commission is of the opinion, and therefore so finds and concludes, that its approval of the recovery of net lost revenues means the recovery of revenue losses, net of

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[1] That would appear to be the case, notwithstanding the fact that the Company, in its response to Item No. 17, of the Commission's July 30, 2009 Pre-Hearing Order Requiring Verified Information, commented as follows:

> The Company believes that variable O&M costs should also be included in the determination of net lost revenues as a marginal avoided cost and would propose to update its calculations of net lost revenues to subtract variable O&M cost in addition to fuel cost in its compliance filing of Rider EE after the Commission issues a final order. The Company is not aware of other costs at the margin, other than fuel and variable O&M, that are avoided as sales are reduced.

all marginal costs, including energy-related and nonenergy-related costs, actually avoided. Such net lost revenues shall be so calculated and otherwise determined, at the latest, under the true-up[1] and measurement and verification provisions of the Settlement Agreement.

Further, in ruling on this matter, the Commission hereby expressly reserves judgment as to all matters concerning the appropriateness of the methodology employed and/or to be employed in the calculation of net lost revenues for purpose of this proceeding, notwithstanding any provision of the Settlement Agreement approved by the Commission or any provision of the Commission's present ruling; and it retains the discretion to review and decide all aspects of any and all issues that may arise in the future in connection with the net lost revenues true-up provisions of the Settlement Agreement.

Finally, to help avoid or mitigate unintended consequences, if any, that could occur from this new regulatory approach, the Commission is of the opinion, and so finds and concludes, that it should continue to closely monitor the Company's overall North Carolina retail earnings as well as the Company's earnings from save-a-watt on a stand-alone basis. Further, should circumstances and/or events so require, the Commission hereby expressly reserves the right to revisit this entire matter and take such further action as may be required.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The evidence in support of this finding is found in the Settlement Agreement, as well as the testimony and exhibits of Duke witness Farmer.

Witness Farmer provided testimony regarding the differences in jurisdictional revenue requirement and customer rate impacts between the original save-a-watt proposal and the modified save-a-watt approach proposed in the Settlement Agreement. He testified that the cumulative jurisdictional revenue that will be billed North Carolina retail customers under the Settlement Agreement is $27.4 million (8.0%) less than the original save-a-watt proposal over the four-year recovery period.[2]

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[1] The Settlement Agreement, in Section H.3., of Exhibit B, sets forth, among other things, "estimated revenue requirements" for the four year term of the agreement, which includes an allowance for "estimated" net lost revenues based upon an avoided cost target achievement factor of 85%. Presumably, such net lost revenues have been calculated by the Company in the manner described by Company witness Farmer.

With regard to recovery of the Company's full revenue requirements during the four-year term of the plan, Section H.6., of Exhibit B, provides for a "final true-up process based on measured and verified results" once the four-year period of the plan is complete. Section H.7., of Exhibit B, provides as follows:

> Net lost revenues are included in the final true-up process at the end of the four-year plan. The outstanding balance of net lost revenues will be adjusted based on <u>actual</u> measured and verified lost revenues. (Emphasis added.)

[2] Witness Farmer clarified that if the recovery of net lost revenues for years 5 and 6 were included when comparing the original save-a-watt proposal to the modified save-a-watt approach, the revenue requirement under the Settlement would exceed that of the first four years of the original save-a-watt proposal. However, under the original save-a-watt proposal, the revenue requirement extended out a number of years – up to 18 years or more. He explained that a fair comparison would necessarily entail comparing the revenue requirement over the life of the original EE measures to the modified proposal under the Settlement Agreement.

Witness Farmer explained that this is in part because the original save-a-watt proposal provided for the recovery of lost revenues and program costs spread out over the life of the DSM and EE programs that gave rise to avoided cost savings. For example, if an EE program had a life of ten years, the recovery of program costs would have occurred over ten years. In contrast, under the provisions of the Settlement Agreement, the recovery of program costs applicable to a particular vintage of EE programs will occur during the program vintage year. In addition, witness Farmer testified that the recovery of net lost revenues, which also would have occurred over the life of an approved EE program under Duke's original proposal, will now be limited to the level of estimated net lost revenues that are expected to occur during the 36-month period that begins as of each initial vintage year of customer participation in Company sponsored programs. Witness Farmer also attributed the lower jurisdictional revenue requirement to the lower percentage of avoided cost recovery, fixed avoided capacity cost rates, and the earnings cap.

According to witness Farmer, the Settlement Agreement jurisdictional revenue requirement assumes Duke achieves 85% of the avoided cost savings targeted across Duke's system. He explained that any difference between amounts due Duke based on actual avoided cost savings realized by customers and amounts billed customers at 85% of target achievement will be collected from or refunded to customers as part of the rider true-ups.

Witness Farmer's testimony and exhibits included calculations of monthly billing factors for residential and nonresidential customers that he used to evaluate the impact of the recovery of EE costs on individual customers. He testified that the monthly billing factor for a residential customer taking service under Rate RS is estimated to be $0.001206 per kWh during the first year of the four-year cost recovery period. The estimated monthly billing factor increases to $0.004207 per kWh in the last year of the four-year cost recovery period.[1] The monthly bill of a typical residential customer using 1,000 kWh will increase by $1.21 and $4.03, respectively, during the first and fourth years.

Because the Public Staff and Duke disagree regarding the allocation of costs among the customer classes and the retail/wholesale jurisdictions, witness Maness also calculated monthly billing factors, reflecting the Public Staff's positions. Maness Exhibit No. 2 shows that the monthly billing factor for a residential customer is estimated to be $0.000710 per kWh during the first year of the four-year cost recovery period and that the estimated monthly billing factor increases to $0.02289 per kWh in the last year of the four-year cost recovery period.[2] These exhibits show that the monthly bill for a typical residential customer using 1,000 kilowatt-hours would increase by an estimated $0.71 and $2.29, respectively, during the first and fourth years, using the Public Staff's cost allocation methods, as described by witness Maness and discussed further with regard to Finding of Fact No. 13.

Witness Farmer testified that residential and non-residential rates will increase by 1.47% and 0.68%, respectively, during the first year of the four-year cost recovery period when compared to 2008 annual jurisdictional revenues. Residential and nonresidential rates will

[1] Monthly billing factor includes gross receipts tax and North Carolina regulatory fee.

[2] Monthly billing factors include gross receipts tax and North Carolina regulatory fee.

increase by 4.93% and 2.14%, respectively, during the fourth year. Witness Farmer added that these rate impacts do not include the savings that will be realized by customers who participate in Company sponsored programs.

Witness Farmer pointed out that customers who participate in programs offered by Duke will likely, depending on the level of participation, reduce their net bill below the level that would have been incurred had Duke's DSM and EE programs not been in place. Customers who do not participate in programs offered by Duke will benefit to the extent Duke's DSM and EE programs lower the marginal cost of energy and capacity below the level that would have been incurred had Duke not been able to realize avoided cost savings.

In addition, witness Farmer explained that the impacts of customers "opting out" of Rider EE (NC) are not included in these rate impacts. In sum, the percentage change in individual customer rates caused by the implementation of Rider EE (NC) will be dependent on the level of power consumed by the individual customer.

The Stipulating Parties have shown that the cumulative jurisdictional revenue requirement is significantly less under the Settlement Agreement than under the original save-a-watt proposal due to lower avoided cost recovery percentages, earnings caps, and the limited recovery period for net lost revenues. While rates and monthly billing factors will increase slightly under the modified save-a-watt proposal compared to rates prior to the four-year cost recovery period, these rate impacts do not take into account the bill reductions participants in Duke's DSM and EE programs will likely experience. These rate impacts are reasonable in light of Duke's increased energy and capacity savings targets, and as such, the Commission concludes that Duke's revised Rider EE reflecting these rate impacts is in the public interest and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence in support of this finding is found in the Settlement Agreement, as well as the testimony and exhibits of Public Staff witness McLawhorn and Duke witness Farmer.

Public Staff witness McLawhorn testified that the Settlement Agreement provides a true-up process to shield ratepayers from the risk of Duke collecting revenues for its DSM and EE programs in excess of what is allowed under the Agreement. Witness Farmer described this true-up process. He testified that the Agreement provides for a series of true-ups that will be conducted to update revenue requirements based on actual customer participation results. According to witness Farmer, revenues will be collected from customers based on the participation true-up results plus an updated forecast of customer participation in Duke's DSM and EE programs. He added that a final true-up process, based on independently measured and verified results, will take place after the evaluation of the program results when the four-year period is complete. At that time, amounts due Duke based on the terms of the Settlement Agreement will be compared to revenues collected from customers.

Witness Farmer testified that the Stipulating Parties have agreed to mitigate any potential overbilling of costs to customers by initially billing customers at a rate that assumes Duke will achieve 85% of its target avoided cost savings goals. He explained that the true-up process will capture the difference between revenues billed customers based on 85% of the target DSM and EE program avoided cost savings billed customers and revenues due Duke based on the applicable percentage of verified DSM and avoided cost savings actually realized. If there are amounts owed to customers, such amounts will be refunded with interest at a rate to be determined by the Commission in the first true-up proceeding in which an overcollection occurs. Witness Farmer further testified that the outstanding balance of net lost revenues will be adjusted based on the actual measured and verified lost revenues determined in the final true-up process.

Additionally, witness Farmer testified that the true-up process will include calculations that ensure that the level of compensation recovered by Duke is capped so that the after-tax rate of return on actual program costs applicable to DSM and EE programs does not exceed the predetermined earnings cap levels set out in the Settlement Agreement. Witness Farmer explained that, if the rate of return on actual program costs is less than the capped level provided for in the Settlement Agreement, then no further adjustment will be made. If, on the other hand, the rate of return on actual program costs incurred exceeds the level provided for in the Agreement, then the excess earnings level will be refunded to customers.

Witness Farmer emphasized that the Settlement Agreement does not guarantee or ensure that Duke will realize or achieve the earnings levels set out in the Agreement. In other words, Duke assumes the risk that projected savings will not materialize and that revenues received from customers, based on the percentage of avoided cost savings retained by Duke, will not result in any management incentive or cover the costs of DSM and EE programs.

Based upon the foregoing and the entire evidence of record, the Commission is of the opinion, and so finds and concludes, that the Stipulating Parties have demonstrated that the true-up process contained in the Settlement Agreement adequately protects ratepayers from the recovery of revenues in excess of what is permitted by the Agreement.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence in support of this finding is based upon the Settlement Agreement, as well as the testimony and exhibits of Duke witness Farmer and Public Staff witness Maness.

Paragraph H.8 of Exhibit B to the Settlement Agreement reads as follows:

> The North Carolina retail revenue requirement applicable to demand-side management, energy efficiency programs, and net lost revenues will be determined by allocating the various inputs to the revenue calculation (avoided costs, program costs, net lost revenues, etc.) to the North Carolina retail jurisdiction and then applying the percentages and other revenue requirement determinants set forth in this agreement.
>
> The Stipulating Parties will present the issue of the appropriate jurisdictional allocation method to the Commission through testimony in this matter. For purposes of determining the North Carolina retail revenue requirement, Duke Energy Carolinas and the Environmental Intervenors agree that (1) for demand-

> side management programs, inputs will be allocated between the North Carolina and South Carolina retail jurisdictions based on contributions to system retail peak demand by all system retail customers based on the cost of service study, and (2) for energy efficiency programs and net lost revenues, inputs will be assigned to the North Carolina and South Carolina retail jurisdictions based on kWh sales to system retail customers from the cost of service study. The program costs allocated under this methodology will be used to calculate the earnings cap.
>
> The Public Staff does not agree with the allocation methodology proposed by Duke and the Environmental Intervenors and instead proposes that (1) for demand-side management programs, inputs will be allocated to the North Carolina retail jurisdiction based on contributions to total system peak demand by all system customers, retail and wholesale, and (2) for energy efficiency programs, inputs should be allocated to the North Carolina retail jurisdiction based on kWh sales to all system customers, retail and wholesale.

The Stipulating Parties accept, generally, the allocation of EE revenue requirements based on kilowatt-hour sales and the allocation of DSM revenue requirements based on contribution to peak demand but disagree on certain issues related to both jurisdictional allocations and customer class allocations.

Duke witness Farmer testified that Duke proposes that the revenue requirement be allocated to North Carolina and South Carolina retail customers only and that no portion of the Settlement Agreement revenue requirement be allocated to wholesale customers. He explained that, because Duke's DSM and EE programs included in the portfolio of programs approved in this proceeding are programs directed specifically to Duke's retail customers, Duke believes it is appropriate to recover the costs of such programs only from these customers. Like PEC and the Commission, Duke interprets G.S. 62-133.9(e) to mean that costs of new DSM and EE programs should "be recovered only from those customer classes eligible to participate in the program and to which the program is targeted." Order Approving Agreement and Stipulation of Partial Settlement, Subject to Certain Commission-Required Modifications, Docket No. E-2, Sub 931, at 30 (June 15, 2009) (PEC Order).

Witness Farmer did not dispute the fact that all customers likely will receive indirect benefits from Duke's DSM and EE programs, but pointed out that, to comply with G.S. 62-133.9(e), the costs of a program or measure should only be recovered from those customers eligible to participate in the program. Duke believes its allocation methodology is more consistent with the North Carolina General Assembly's use of the words "only" and "directly" in this statute, which provides that:

> The Commission shall determine the appropriate assignment of costs of new demand-side management and energy efficiency measures for electric public utilities and shall assign the costs of the programs <u>only</u> to the class or classes of customers that <u>directly</u> benefit from the programs. [Emphasis added.]

G.S. 62-133.9(e).

Witness Farmer also testified that Duke proposed in the Settlement Agreement that inputs applicable to DSM programs be allocated between North Carolina and South Carolina retail jurisdictions based on contributions to system retail peak demand by all system retail customers based on Duke's cost of service study. The North Carolina retail amount would be further allocated between residential and non-residential customer classes based on the relative contribution of each customer class to the North Carolina retail peak demand. Inputs for EE programs and net lost revenues would be assigned to the North Carolina and South Carolina retail jurisdictions based on kWh sales to system retail customers, also from the cost of service study, but, as explained below, in a manner such that residential customers pay for residential programs and non-residential customers pay for non-residential programs. Program costs applicable to DSM and EE programs would be allocated between North Carolina and South Carolina jurisdictions on the same basis as revenue requirements.

Witness Maness testified that the Public Staff believed that G.S. 62-133.9(e) does not control the jurisdictional allocation of system DSM and EE costs and revenues to North Carolina retail operations. He testified that G.S. 62-133.9(e) refers specifically to assignments of costs to customer classes; there is no language in the statute that refers to the methods to be used to allocate costs between jurisdictions for North Carolina retail ratemaking purposes. Witness Maness noted that, in Rule R8-69(b)(1), the Commission refers to jurisdictional allocation and class assignment as separate processes and associates G.S. 62-133.9(e) only with class assignment. Further, he pointed out that, in the rulemaking proceeding that resulted in Rule R8-69, the Commission declined to indicate that the statute applied to jurisdictional allocation and explicitly declined to require that the DSM and EE costs be recovered solely from retail customers.

Witness Maness explained that the Public Staff believes that allocating costs only to the retail jurisdictions, as Duke proposes, does not reflect the system benefits that will arise from implementation of DSM and EE programs. According to witness Maness, the benefit of a DSM or EE program to the utility system is the long-term reduction in cost of service achieved by the utility as a result of it acquiring DSM and EE resources to serve load growth at a lower cost than would have been incurred had the utility instead been required to serve that load growth through acquisition of supply-side resources. He testified that this reduction in cost can typically be expected to accrue to the benefit of all system customers because the costs themselves, if incurred, would be allocated to the entire system, including the wholesale jurisdiction. The Public Staff believes that the appropriate and reasonable manner of allocating the costs and incentives reflected in the DSM/EE rider is to treat them as total system costs and to allocate them across the total system, including the wholesale jurisdiction.

Witness Farmer clarified the difference in opinion between the Public Staff and Duke as to the allocation of costs between residential and non-residential customers. He explained that Duke believed that residential customers should pay the cost of the residential programs and that non-residential customers should pay for the non-residential programs. Because DSM programs for residential and non-residential customers are similar in nature, Duke's proposed allocation of DSM costs across system retail customers based on system peak demand accomplishes this objective. In the case of EE programs, however, residential and non-residential costs and benefits can be quite different in nature. Accordingly, Duke's proposed cost recovery mechanism captures the cost of residential EE programs offered to retail customers across the system separately from the cost of non-residential EE programs offered to retail customers across the system. For the residential class and the non-residential class, separately, the North Carolina portion of retail system EE costs would be determined based on the North Carolina kWh sales for the customer class relative to the system retail kWh sales for the customer class. The rider amounts proposed in Farmer Settlement Exhibit 3 and Farmer's settlement testimony reflect the allocation methods as proposed by Duke. Program costs applicable to DSM and EE programs would be allocated between North Carolina and South Carolina jurisdictions on the same basis as revenue requirements.

The Public Staff, on the other hand, believes that allocation of both system DSM and system EE revenues and costs to the North Carolina jurisdiction should precede any allocation of revenues and costs to customer classes. Then, after jurisdictional allocation, allocation of North Carolina retail revenues and costs between residential and non-residential customers should be based on relative residential and non-residential contributions to kWh sales and peak load within the North Carolina jurisdiction itself, not on a determination of the customer class at which a program is targeted. In other words, the Public Staff recognizes that class allocation is governed by G.S. 62-133.9(e), but interprets this provision to mean that allocation of North Carolina DSM and EE revenue requirements to customer classes should be based on the same contribution to system peak load and system energy requirements methodology that it believes is appropriate for jurisdictional cost allocations. The Public Staff acknowledged that the Commission has recently disagreed with it on the class allocation issue, in Docket No. E-2, Sub 931, but requested that the Commission reach a different conclusion in this proceeding.

In the PEC Order, the Commission concluded as follows:

> It is a well-established principle of statutory interpretation in North Carolina that a statute should not be interpreted in a manner which would render any of its words superfluous. Each word of a statute is to be construed as having meaning, where reasonable and consistent with the entire statute, because it is always presumed that the Legislature acted with care and deliberation. State v. Haddock, _____, N.C. App. _____, 664 S.E.2d 339, 345 (2008); State v. Ramos, _____, N.C. App. ____, 668 S.E.2d 357, 363 (2008).
>
> The Commission agrees with the Public Staff that, to some degree, all customers benefit from the implementation of new DSM and EE programs. To conclude, however, that this general benefit encompasses the direct benefit contemplated by the General Assembly [in G.S. 62-133.9(e)] fails to interpret the statute in a logical manner. Accordingly, the Commission agrees with PEC that to interpret the statute in the manner proposed by the Public Staff would render the words "directly" and "only" meaningless. Clearly, the General Assembly intended for those words to have meaning and the most logical meaning they can have is that the cost of a new DSM/EE program is to be recovered only from those customer classes eligible to participate in the program and to which the program is targeted. While the Public Staff is correct that all retail customer classes benefit from DSM/EE programs, the Commission is of the opinion that there would have been no need for such a statutory provision if not to direct the

Commission to allocate these costs in a different manner. The Commission concludes that the law favors PEC's interpretation and disfavor's the Public Staff's position.

The Commission is unaware of any change in the law, nor has the Public Staff brought forth any new evidence or arguments since the Commission's June 15, 2009 PEC Order that convinces the Commission that it should change its position on this issue. Accordingly, for the reasons stated in the PEC Order, the Commission sides with Duke and concludes that the costs of residential programs should be borne by the residential customer class and that costs of non-residential programs should be borne by the non-residential customer class; and that Duke's proposed methods for determining the costs for North Carolina residential and non-residential classes are appropriate.

As to the issue of inclusion of wholesale customers in the jurisdictional cost allocation, the Commission notes that the Public Staff was one of the Stipulating Parties in Docket No. E-2, Sub 931, and as such, agreed that PEC's expenses for DSM and EE measures should be allocated to the North Carolina and South Carolina retail jurisdictions and not the wholesale jurisdiction. In this proceeding, the Public Staff did not agree to so stipulate and is making similar arguments to those of the Attorney General that were rejected in the PEC Order. Again, the Public Staff has presented no evidence or arguments to lead the Commission to decide differently here. The Commission finds that the costs and incentives at issue are for DSM and EE programs targeted to retail customers. Wholesale customers cannot participate directly in these programs. Any benefit that wholesale customers receive is clearly an indirect benefit. Finally, Duke's North Carolina wholesale customers are electric power suppliers covered by Senate Bill 3. Just like Duke, they are required to meet their own requirements for the use of renewable energy and EE. As they do so, it is reasonable to assume that their retail customers will pay for their programs, just like Duke's retail customers will pay for its programs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

The evidence in support of this finding is based upon the Settlement Agreement and testimony of Duke witness Schultz and Environmental Intervenors witness Wilson.

Witness Schultz explained the terms in the Settlement Agreement relating to the Advisory Group. He testified that, as in Duke's initial proposal, the Settlement Agreement recognized that the successful development and implementation of EE programs required constant monitoring and modification, and that an advisory group is helpful in that regard. Specifically, the Settlement Agreement provides that the Advisory Group will be established for the term of this Settlement Agreement. Witness Schultz testified that the role of the Advisory Group is to collaborate on new program ideas, review modifications to existing programs, ensure greater public understanding of the programs and funding, and review the measurement and verification process. Witness Wilson also testified that the Advisory Group is intended to ensure transparency and encourage new ideas. The Stipulating Parties envision that the Advisory Group will be comprised of a broad spectrum of regional stakeholders that represent balanced interests in the programs, as well as national EE advocates and experts. The Advisory Group will meet at least twice each year and may establish working groups on specific topics. A third party will facilitate the Advisory Group's discussions.

The Commission finds that the Advisory Group provides an important forum for Duke to receive input from a variety of stakeholders. The implementation of the Advisory Group will facilitate innovation and accountability. Accordingly, the Commission concludes that the Advisory Group is in the public interest.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 15 THROUGH 17

The evidence in support of these findings can be found in the Settlement Agreement, the settlement testimony of Duke witness Wiles, and the entire record in this proceeding.

With respect to the nature of the accounting data to be submitted by the Company in periodic reports to the Commission regarding save-a-watt, in their proposed order, the Stipulating Parties stated that Company witness Wiles

> . . . described changes to the accounting and reporting treatment originally requested by the Company as a result of the Settlement Agreement and the Commission's Order. He explained that in compliance with the Order, the Company will include actual program revenues and actual program costs for purposes of calculating and reporting its regulated earnings to the Commission in its quarterly ES-1 reports. It will provide supplementary schedules setting forth the Company's jurisdictional earnings excluding the effects of its DSM and EE programs. <u>The Company also will provide schedules separately stating the costs associated with each program or activity, and actual revenues received from the DSM and EE programs.</u> Witness Wiles testified that Duke Energy Carolinas will provide detailed calculations supporting these . . . schedules. (Emphasis added.)

The Commission is of the opinion that the information and data described in the narrative underlined immediately above, as proposed by the Company for submission to the Commission, would not, in fact, constitute compliance with the Commission's February 26, 2009 Order, in the instant regard, and as such, would be inadequate from the standpoint of satisfying the Commission's needs. In contrast to the foregoing highlighted information, which the Company has proposed to provide, the February 26, 2009 Order, in pertinent part, actually provided as follows:

> Furthermore, the Commission is of the opinion and, therefore, so finds and concludes that . . . the Company should be required . . . (3) to provide schedules separately stating the earnings impact of its DSM and EE programs on a combined basis as well as on a stand-alone, program-class basis, that is, with earnings from DSM programs, collectively, and earnings from EE programs, collectively, shown separately. [The Commission also required, in its Order, that detailed calculations of the foregoing be provided, including schedules and/or calculations showing, at a minimum, actual revenues; expenses; taxes; operating

income; investment base, including major components where applicable; and applicable capitalization ratios and cost rates, including overall rate of return and return on common equity.]

In consideration of the foregoing, the Commission is of the opinion, and, therefore, so finds and concludes, that, in ruling on this matter, it should clarify its earlier findings and conclusions in regard to the specific nature of the accounting procedures and the reporting format that the Company should be required to follow in the present regard. Accordingly, for the reasons previously set forth in the Commission's February 26, 2009 Order, Duke shall not follow the accounting and reporting procedures that it has proposed with respect to its save-a-watt model, but, instead, shall be, and hereby is, required to follow the approach as set forth below:[1]

> With regard to save-a-watt, the Company shall be, and hereby is, required: (1) to include all actual program revenues (estimated, if not known) and only actual program costs (estimated, if not know) for purposes of calculating and presenting its regulated earnings to the Commission for ES-1 purposes; (2) to provide supplementary schedules setting forth the Company's jurisdictional earnings excluding the effects of EE and DSM programs; and (3) to provide schedules separately stating the earnings impact of its DSM and EE programs on a combined basis as well as on a stand-alone, program-class basis, that is, with earnings from DSM programs, collectively, and earnings from EE programs, collectively, shown separately. Detailed calculations of the foregoing shall also be provided. Such schedules and/or calculations shall show, at a minimum, actual revenues; expenses; taxes; operating income; investment base, including major components where applicable; and applicable capitalization ratios and cost rates, including overall rate of return and return on common equity. Net lost revenues realized (estimated, if not known) for each reporting period shall be clearly disclosed as supplemental information.

In regard to other accounting matters, witness Wiles, in his June 19, 2009 settlement testimony, explained that certain accounting rules require that the Company record a regulatory asset on its books if the level of save-a-watt revenues recoverable under the Settlement Agreement is expected to be greater than the level of revenues billed under the rider. Alternatively, according to witness Wiles, Duke will record a regulatory liability if the level of revenues billed customers is in excess of the level expected to be ultimately recoverable.

Witness Wiles explained that, in those situations where Duke owes customers, the Company will record a reduction to revenues in recognition of the fact that Duke has an obligation to refund overcollected amounts.

Witness Wiles described the recommended method of accounting for amounts owed the utility under alternate rate recovery plans, such as save-a-watt. He explained that the Emerging

[1] This accounting and reporting approach is virtually the same as that ordered in regard to the Matter of Application by Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc., for Approval of Demand Side Management and Energy Efficiency Cost Recovery Rider Pursuant to G.S. 62-133.9 and Commission Rule R8-69, in Docket No. E-2, Sub 931. (See Order issued November 25, 2009.)

Issues Task Force[1] reached consensus that, once specific events have occurred that provide for future customer billings, the utility can then recognize the additional revenues if certain conditions are met.

According to witness Wiles, a rate recovery plan, such as save-a-watt, must first be established by an order from the Commission that allows for the automatic adjustment of future rates.[2] Second, the amount of additional revenues for the period must be objectively determinable and probable of recovery. Lastly, witness Wiles explained that the revenue in question must be collected within 24 months following the end of the annual period in which they are recognized. Witness Wiles further observed that, while the terms of the Settlement Agreement meet these conditions, a Commission order approving the Agreement should acknowledge clearly that future rates may be adjusted in accordance with these provisions.

Finally, consistent with Commission Rule R8-27(a)(2), witness Wiles requested that the Commission, in ruling on this matter, include an ordering paragraph authorizing Duke, for regulatory accounting purposes, to use regulatory asset and liability accounts for purposes as described in his settlement testimony.

No intervenor offered any evidence or argument in contravention of witness Wiles' settlement testimony. In addition, no intervenor cross-examined witness Wiles, nor was he asked any questions by the Commission.

Based upon the foregoing and the entire evidence of record, the Commission finds and concludes that the accounting procedures described by witness Wiles, in the instant regard, are reasonable. Consequently, pursuant to Commission Rule R8-27(a)(2), the Commission authorizes Duke, for North Carolina jurisdictional regulatory accounting purposes, to utilize Account 182.3 – Other Regulatory Assets and Account 254 – Other Regulatory Liabilities for the present purposes as described by witness Wiles. The Commission further finds and concludes that its approval of the Settlement Agreement in this Order is sufficient to support deferral accounting for North Carolina jurisdictional regulatory accounting purposes.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 18

The evidence in support of this finding can be found in the Commission's February 26, 2009 Order, the testimony of Public Interest Intervenors witness Colton, Public Staff witness McLawhorn and the rebuttal testimony of Duke witness Smith.

In its joint post-hearing brief, NC WARN and the Public Interest Intervenors observed that, the Commission, in its previous Order, held that Duke's proposed low income EE programs "strike an appropriate balance between assisting low-income customers and maintaining

[1] The Emerging Issues Task Force is an organization formed in 1984 by the Financial Accounting Standards Board (FASB) to provide assistance with timely financial reporting. The main purpose of the task force is to identify emerging issues and resolve them with a uniform set of practices, before widespread divergent methods arise.

[2] Based upon witness Wiles' testimony, the Commission understands that verification and/or potential modification of the adjustment to future rates by the Commission would not preclude the adjustment from being considered automatic.

cost-effectiveness." They then argued that such "balance," based on previous levels of recommended usage reduction, must now be reviewed and modified by the Commission, as Duke has since committed in its proposed Settlement Agreement to substantially increase energy savings for EE program participants by 250%, while its commitment to low income and low and fixed income senior customers remains unchanged and relatively meaningless. According to NC WARN and the Public Interest Intervenors, to more than double the total usage reduction proposed through save-a-watt without also substantially enhancing the EE programs specifically directed towards Duke's low income and low and fixed income senior customers is unreasonable.

NC WARN and the Public Interest Intervenors requested that the Commission disapprove Duke's proposed Settlement Agreement because Duke's proposed Settlement Agreement, if approved, would not provide rates and services that are just, reasonable, or nondiscriminatory as related to low income ratepayers, in violation of both G.S. 62-131(a) and (b) and G.S. 62-140(a). NC WARN and the Public Interest Intervenors argued that, as a result, Duke's proposed Settlement Agreement is not in the public interest, as required under G.S. 62-2, and should therefore be disapproved or significantly modified by the Commission.

According to NC WARN and the Public Interest Intervenors, the just, reasonable, and nondiscrimination standard requires that Duke not exclude the vast majority of its low income customers from its save-a-watt EE programs. NC WARN and the Public Interest Intervenors asserted that approval of Duke's Settlement Agreement, as currently proposed, will violate both G.S. 62-131 and 62-140 by systemically and intentionally excluding the vast majority of Duke's low income and low and fixed income senior customers from its proposed EE programs, and will prohibit those same low income customers from obtaining any meaningful EE usage reduction. This exclusion, in effect, will cause Duke's low income and low and fixed income senior customers to assume increased energy bills by denying them the same program benefits that Duke's EE program participants will be able to receive. NC WARN and the Public Interest Intervenors stated that Duke's own witness, Judah Rose, acknowledged this result in discussing the impact of Duke's EE plan on nonparticipants, stating:

> However, energy efficiency might unintentionally increase average electric rates for, and bills of, nonparticipants as utility fixed costs are carried by fewer sales. Further, the greater the energy efficiency, the greater the chance that this might happen. Put another way, rates could increase for those customers that simply choose not to participate.

Witness Rose also acknowledged that:

> However, as energy efficiency lowers the electricity demand of program participants, the utility's fixed costs (e.g., capital recovery of legacy investment) are borne by lower amounts of electricity sales, and hence, average rates and bills of nonparticipants could unintentionally increase under some specific circumstances.

In concluding that Duke's EE program will benefit all customers, witness Rose acknowledged that this is "assuming that all customers participate equally in the program. . . ."

NC WARN and the Public Interest Intervenors asserted that, under G.S. 62-2(a)(4) and (b) (2007), the Commission must ensure that a public utility, such as Duke, does not institute any rate plan or service programs that would result in the systemic and unilateral exclusion of the vast majority of a segment of its customers from the benefits of any program, or that result in those excluded customers being prejudiced or disadvantaged by higher rates or bills than those charged to non-excluded customers. Without substantial modifications to the proposed Settlement Agreement, such exclusion of, and prejudice to, Duke's low income and low and fixed income senior customers will occur.

NC WARN and the Public Interest Intervenors further argued that this systemic exclusion by Duke of almost all low income and low and fixed income senior residential customers is intentional. Regarding the costs of its energy efficiency programs, Duke "has the incentive to get those costs lower, because the more energy it can save, the greater it can earn under the rate rider provisions that it's proposing. . . ." Because Duke's proposed Settlement Agreement is still based on an "avoided cost" model, it allows the Company greater financial benefits for those programs where the spread between the avoided costs and the program costs are the greatest (i.e., where the cost-effectiveness is the highest). Given this incentive structure created by save-a-watt (unchanged by any possible concessions brought about by the proposed Settlement Agreement), NC WARN and the Public Interest Intervenors maintained that Duke is incentivized to "cream-skim," i.e., to take only those programs that are the most cost-effective, and exclude other cost effective programs (such as low-income programs). In sum, Duke, in order to maximize its revenue under the save-a-watt plan, has a financial incentive not to allow most of its low income and low and fixed income senior customers to participate in its EE programs, even if doing so would still be "cost effective."

NC WARN and the Public Interest Intervenors observed that the Public Utilities Act prohibits discrimination among a public utility's customers and specifically states that:

> No public utility shall, as to rates or services, make or grant any unreasonable preference or advantage to any person or subject any person to any unreasonable prejudice or disadvantage. No public utility shall establish or maintain any unreasonable difference as to rates or services either as between localities or as between classes of service. (G.S. 62-140(a)) (2007).

According to these Intervenors, the legislative purpose of the "no discrimination" law is to prohibit a public utility from unreasonably discriminating among its customers. (State ex rel. Utilities Comm. v. Southern Bell, 88 NC App. 153, 363 S.E.2d 73 (1987).

NC WARN and the Public Interest Intervenors argued that one of the goals of the electric utility rate structure established under the Public Utilities Act is the elimination of intra-class prejudice or disadvantage, such as intra-class cross-subsidies. (State ex rel. Utilities Comm. v. Edmisten, 314 NC 122, 169, 333 S.E. 2d 453, vacated on other grounds, 477 US 902, on remand 318 NC 279, 347 S.E.2d 459 (1985). Where substantial differences in services or conditions exist, the unreasonable application of the same rates may be discriminatory and improper under G.S. 62-140(a). (State ex rel. Utilities Comm. v. Edmisten, 291 NC 424, 230 S.E. 2d 647 (1976).

NC WARN and the Public Interest Intervenors explained that, even if under Duke's proposed Settlement Agreement the same increased rate would be charged to middle and upper class customers/EE plan participants and low income customers/EE plan non-participants, application of the same rate is unreasonable, discriminatory, and improper under G.S. 62-140(a). That is because there are substantial differences in the conditions and services Duke is offering to each group. This unequal ability to participate in EE usage reduction programs and thus benefit from lower rates results from Duke's unilaterally imposed program eligibility and availability restrictions. According to NC WARN and the Public Interest Intervenors, such a discriminatory cost-shifting or cross-subsidization between participating customers and nonparticipating customers would in fact still occur in the EE Rider and programs Duke proposes to implement in the Settlement Agreement.

NC WARN and the Public Interest Intervenors stated that, rather than address this increased disparity between its residential customers, Duke's proposed Settlement Agreement does not propose any specific portfolio of low income EE programs. Instead, it merely states that Duke will "convene the Advisory Group . . . to guide efforts to expand cost-effective programs for low-income customers." This discussion, however, occurs only after the Commission approves the Company's efficiency plan for the year. By design, therefore, this work will not influence what the Company offers in the near-term. The Company does not commit to expanding its low-income programs.

Moreover, NC WARN and the Public Interest Intervenors explained that there is no time frame placed on the work of the Advisory Group regarding low-income programs. For example, the Advisory Group only meets twice a year. While the Advisory Group may "establish working groups on specific topics," no specific commitment to establish a low-income working group is made, let alone a work group with a specific workplan and a specific timeframe within which to complete that workplan. The Advisory Group delay exacerbates the exclusion of many Duke ratepayers from benefiting from save-a-watt.

In order to address these issues, NC WARN and the Public Interest Intervenors offered the following recommendations to the Commission for inclusion in the final order in this docket:

1. In addition to offering weatherization services to customers below 150% of the Federal Poverty Level (FPL), Duke should commit to implementing a baseload electric usage reduction program modeled on the "exemplary" low-income programs presented in the catalogue of such programs developed by the American Council for an Energy Efficient Economy (ACEEE), previously discussed in this proceeding.

2. In addition, Duke should commit to importing its own successful low-income programs from Indiana and Ohio to North Carolina beginning in the first year. Duke should also incorporate into its North Carolina program two key elements of its existing Indiana refrigerator replacement program: a) inclusion of households below 150% of the FPL; and b) inclusion of

households with Duke customers, whether or not the household lives in a 100% electric usage home.

3. The scope and funding for the program components identified above should be made subject to the deliberations of the Advisory Group identified in the Settlement Agreement. A plan to deliver efficiency services, including baseload electric efficiency services, to low-income and low and fixed-income senior customers should be delivered to the Commission for approval within 60-days after a final order in this proceeding. The Advisory Group should be directed to respond to the question: what level of programs should be offered to low-income and low and fixed-income senior customers? The Settlement Agreement should be modified, however, and the Order should be clear that the question of *whether* such programs should be offered to low-income and low and fixed-income senior customers has been decided.

4. The plan to be developed by the Advisory Committee should include:

- a specific dollar commitment to low-income programs, including either a specific commitment to the number of low-income units to be served, or a specific proportion of total residential budget to be devoted to low-income customers;
- a commitment to pursue electric baseload programs, including refrigerator replacements;
- a commitment to deliver energy efficiency services to households with income below 150% of the FPL;
- a commitment to a program directed specifically toward rental properties, including investments directed toward property owners participating in the Section 8 housing program; and
- a specific workplan through which housing units treated not only through the Department of Energy's Weatherization Assistance Program (WAP), but housing units constructed or rehabilitated through public programs such as HOME and the Low-Income Housing Tax Credit (LIHTC), will be reached.

5. Duke should amend its 2009 Integrated Resource Plan (IRP), filed in Docket No. E-100, Sub 124, to reflect its save-a-watt goals and include such goals in future IRP filings. Decisions about the construction or cancellation of generating plants should reflect mandatory save-a-watt goals.

Duke argued that the concerns expressed by Public Interest Intervenors witness Colton in his supplemental testimony are no different from the recommendations he made during the August 2008 evidentiary hearing in this docket. As noted by Duke witness Smith, the Company addressed those concerns in its testimony as well as in its October 7, 2008 proposed order. Furthermore, according to Duke, the Commission ruled on the recommendations made by witness Colton in its February 26, 2009 Order. Specifically, at pages 21 and 22 of the Order the Commission discussed witness Colton's testimony as follows:

> . . . Colton criticized Duke's proposed portfolio of EE programs as failing to serve low-income households, and described a number of exemplary programs

> that he suggested the Company model its programs after instead. Specifically, witness Colton expressed concern that the Low Income Energy Efficiency and Weatherization Program will not be widely available to low-income households because its application is restricted to households with incomes of 150% to 200% of the federal poverty level and is limited to owner-occupied, single-family, all-electric residences. Witness Colton criticized the Company for assuming that weatherization agencies are available to distribute and install weatherization and starter kits. He based this criticism on his assumption that Duke is planning to leverage federal funds for these purposes, and federal regulations disallow federal weatherization assistance for households above 125% of the poverty level. Witness Colton cited the Public Service of Indiana's (now Duke Energy Indiana) low-income program as an exemplary program that Duke should emulate.

Duke pointed out that the Commission concluded that it was ". . . of the opinion that Duke's Low Income Energy Efficiency and Weatherization Assistance Program strikes an appropriate balance between assisting low-income customers and maintaining cost-effectiveness . . . and that the Low Income Energy Efficiency and Weatherization Assistance Program, as proposed, is in the public interest and will benefit Duke's customer body as a whole. As such, the Commission approves this program."

Duke explained that, while witness Colton urged the Commission to require the Company to commit to the implementation of a refrigerator replacement program, the Company's Commission-approved Low Income Energy Efficiency and Weatherization Assistance Program already contains a refrigerator replacement component. Further, as Public Staff witness McLawhorn testified, the Settlement Agreement contains a provision requiring the Company to make residential programs available to low-income customers without regard to whether they own or rent homes. According to witness McLawhorn, the Company has also committed to pursuing partnerships with third-party agencies to implement programs and offer assistance to low-income customers. He further stated that the Public Staff will continue to monitor the extension of EE programs and benefits to all customers, regardless of income, through its involvement in stakeholder groups or other mechanisms.

The Commission agrees with Duke that it has already addressed Duke's portfolio of EE programs in its February 26, 2009 Order, including the Low Income Energy Efficiency and Weatherization Program. The only substantive issue that the Commission sees here is whether Duke's proposal to substantially increase energy savings from EE programs creates a requirement that Duke now also enhance the EE programs specifically directed towards Duke's low income and low and fixed income senior customers, as herein argued by NC WARN and the Public Interest Intervenors.

NC WARN and the Public Interest Intervenors have asserted statutory legal arguments for their position that Duke's low income and low and fixed income senior customers are a separate class of customers that are entitled to a proportionate share of an expanding EE pie. While the Commission does indeed agree that it is important to offer meaningful programs to all spectrums of Duke's customer base, it does not believe that the statutes require some type of mandatory proportional balance between different types of customers.

G.S. 62-131(a), G.S. 62-131(b), and G.S. 62-140(a) allow the Commission considerable discretion in weighing the evidence and determining what is a reasonable rate and what constitutes unreasonable discrimination. The Commission has previously held that the proposed EE programs strike an appropriate balance as to assisting low-income customers. The Commission has again considered the arguments presented on this issue and reaches the same conclusion. The Commission does not believe that G.S. 62-131(a), G.S. 62-131(b), and G.S. 62-140(a) are violated by the present proposal. The Commission therefore concludes that NC WARN and the Public Interest Intervenors have not presented any new or different evidence to justify changes for low-income customer programs, and have not presented a case for modification or rejection of the Settlement Agreement.

That having been said, the Commission does find value in specifically directing the Advisory Group to study the feasibility of expanding programs for low-income customers to the extent possible. The Commission does not, however, direct that the Advisory Group respond to a specific timetable for a response, nor require specific mandates on required action as requested by NC WARN and the Public Interest Intervenors. There is simply no precedent to support such action.

NC WARN and the Public Interest Intervenors also maintained that Duke should be required to incorporate save-a-watt goals into the IRP planning process. As the Commission has scheduled an evidentiary hearing on the 2009 IRP plan filed by Duke in Docket No. E-100, Sub 124, it agrees that it is important that the information and tables presented in the IRP plan properly reflect the most recent and appropriate information regarding Duke's EE and DSM goals. Therefore, the Commission directs Duke to address this issue in its direct testimony to be filed in the IRP docket and to file any other revised information as may be necessary with its direct testimony.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 19

The evidence in support of this finding can be found in the Settlement Agreement, as well as the exhibits and testimony of Public Staff witness McLawhorn, Environmental Intervenors witness Wilson, and Company witnesses Schultz and Farmer.

Duke witness Schultz testified that the Settlement Agreement furthers the important goal of providing an incentive to the Company and its customers to be aggressive in developing new EE and DSM programs. The Agreement also reflects the Company's concept that compensation for successful implementation of EE and DSM programs should be predicated on a discount to the "avoided costs" of a power plant in order to place EE and DSM on a level playing field with supply-side resources. He emphasized that EE and DSM programs enable the Company to avoid future generation costs, benefiting all customers. In addition, witness Schultz explained that DSM and EE programs allow the Company to meet customer demand for electricity with a zero-emission resource and to lower usage and bills for customers who participate in these programs.

As noted by witness Schultz, the Agreement sets an aggressive target for the Company to deliver $754 million of avoided future generation costs. This is a dramatic increase in results from EE and DSM programs in comparison with the original save-a-watt proposal. Public Staff witness McLawhorn testified that considering the increase in the projected energy savings, the Public Staff believes that the incentives that Duke has the opportunity to recover under the Settlement Agreement are more reasonable than those set forth in the original save-a-watt proposal.

Environmental Intervenors witness Wilson agreed that the Settlement Agreement protects ratepayers and the environment while providing the Company with a reasonable incentive to pursue EE, and is therefore in the public interest. He explained that the revised level of avoided cost recovery is in the public interest because it is set at a level that gives Duke the ability to recover its program costs plus achieve a reasonable level of earnings under the cap. However, if the Company's costs are higher than expected, then it might not achieve the full level of earnings allowed under the cap. Witness Wilson asserted that in combination with the earnings cap, the avoided cost recovery structure provides customers with an assurance that the Company has an incentive to control costs. Further, as witness Schultz explained, under the Settlement Agreement, the Company will only get paid for implementing programs that produce actual energy and capacity savings, as measured and verified by an independent third party. In other words, Duke assumes the risk of recovering its EE and DSM program costs or any management incentive based upon its performance.

One question that was raised during the Settlement Hearing was whether the Commission should mandate that Duke achieve the targets set out in the Settlement Agreement. NC WARN and the Public Interest Intervenors argued that, on its face, the Settlement Agreement is only for the first four years, although it does contain long-term performance goals, and that Duke agreed to a ramped target of two percent savings over the first four years and then an additional one percent a year after that. NC WARN and the Public Interest Intervenors noted that the result of that commitment is best shown by Environmental Intervenors witness Wilson in Exhibit 2 to his direct testimony.

NC WARN and the Public Interest Intervenors further argued that, at best, the new commitment for savings in the stipulation brought a commitment made earlier by Duke up a couple of years. The difference between the Settlement Agreement and the earlier save-a-watt commitment is that the new commitment allows Duke to start later but moves the one percent annual savings up two years. NC WARN and the Public Interest Intervenors noted that Duke CEO Rogers, in his testimony in the record, touted Duke's agreement with the national efficiency associations to start an EE program in 2015 that will increase one percent a year for 10 years. NC WARN and the Public Interest Intervenors pointed out that, in the first set of hearings on save-a-watt, Duke witness Schultz, and others, made it clear that this commitment was contingent "upon approval of its save-a-watt initiative." In the most recent hearing on the stipulation, witness Schultz also agreed that Duke should be able to meet its goals, but continued to hedge when pushed on whether Duke would actually meet those goals. He testified that:

> We are designing our programs to go after all cost-effective energy efficiency and striving towards the commitments that are here in this four-year plan and our national commitment assuming we still have the save-a-watt mechanism in place at one percent a year.

NC WARN and the Public Interest Intervenors argued that, in essence, Duke's commitment to EE is only as long as save-a-watt is in place.

NC WARN and the Public Interest Intervenors stated that the recommendations by earlier witnesses of an immediate one percent annual savings were not given credibility by Duke witnesses. In the earlier hearings, NC WARN witness Blackburn testified that a one percent a year decrease in demand was economic and achievable through proven EE measures, although he believed that the one percent could start almost immediately, with a 10% decrease in demand in ten years.[1] He based this on studies in North Carolina, Duke's own Forefront study and what was being achieved in other states. Public Interest Intervenors witness Colton testified that many of the programs Duke should consider to achieve this were actually in use by Duke in other states. The principal differences between those recommendations and the goals in the Settlement Agreement are that Duke ramps up its save-a-watt programs over four years and then goes into the one percent a year savings.

If the Commission approves the Settlement Agreement in full or in a modified form, then NC WARN and the Public Interest Intervenors believe that the Commission, in its Order, should make the "goals" in the agreement binding on Duke. Otherwise, the commitment has relatively little substance and may not influence the way Duke, as a corporation, does business in North Carolina.

NC WARN and the Public Interest Intervenors offered that, if at some future point Duke wishes to modify its save-a-watt goals, it should be able to do so. Increasing the levels of EE savings could be simply a part of the annual REPS reporting requirement. On the other hand, if Duke wished to decrease its level of EE savings, it should be required, at a minimum, to show cause why the goal is no longer economical, as well as show that a lower goal was in the public interest. The Commission should then ask Duke serious questions about its corporate commitment to EE as the "fifth fuel," as characterized by witness Rogers.

NC WARN and the Public Interest Intervenors asserted that this is in line with the "off-ramp" provisions of Senate Bill 3. Pursuant to G.S. 62-133.8(i)(2), the Commission has the authority to modify or delay the Senate Bill 3 provisions if it finds that it is in the public interest to do so and if it finds that the utility demonstrates it "made a reasonable effort to meet the requirements."

Witness Schultz responded that the Company has "taken a different tack from the mandate approach to create something that really aligns all parties and their interests." In addition, as witness Farmer explained, the Company's results are dependent upon customer acceptance of the Company's DSM and EE programs: "If customers don't participate in the programs then there are no results." Further, it would be difficult for the Company or the Commission to mandate customer performance in these programs. Regardless, witness Farmer testified that the Company has an incentive to achieve these targets not only to increase its chances to recover its program costs and a management incentive, but also because these targets are reflected in the Company's IRP Plan. To fall short of achieving these targets would "put us

[1] See report of Dr. Blackburn, "North Carolina's Energy Future: Data Shows We Can Close Power Plants Instead of Building New Ones," March 31, 2009, filed in Docket No. E-7, Sub 790 and Docket No. E-100, Sub 118.

in a . . . spot. It's tough to build a plant in that kind of a time frame, so you end up in the short term . . . looking at some alternative regarding purchase power," testified witness Farmer.

In response to questioning by Chairman Finley, witness McLawhorn testified that Senate Bill 3 contains REPS that function as a mandate. The ability of Duke and other North Carolina utilities to meet this mandate is derived, in part, by implementing EE programs. Chairman Finley asked, "So Senate Bill 3 has both carrots and sticks? It has mandates and it has incentives?" to which witness McLawhorn answered affirmatively.

The Commission sees no need or requirement to supplement this legislative scheme by mandating Duke to reach the DSM and EE targets set out in the Settlement Agreement, especially where results are so dependent on customer participation, and where the Company has plenty of incentive to achieve these targets without a Commission directive.

The North Carolina General Assembly has recognized that an increased emphasis on EE is necessary, by declaring through the enactment of Senate Bill 3 that the promotion and development of DSM and EE resources in North Carolina is in the public interest. To implement this policy, the General Assembly authorized the Commission to approve a broad array of incentives, including "rewards based on capitalization of a percentage of avoided costs achieved" and "[a]ny other incentive that the Commission determines to be appropriate." (G.S. 62-133.9(d)). In addition, Commission Rules R8-68 and R8-69 implementing Senate Bill 3 expressly provide that the Commission will review and evaluate, as a package, proposed DSM and EE programs, cost recovery, lost revenue, and management incentive mechanisms. Under Commission Rules R8-68 and R8-69, recovery of lost revenues and management incentives are appropriate considerations within a least-cost framework. The modified save-a-watt approach, including limited recovery of net lost revenues and a management incentive based on a percentage of avoided costs, is consistent with G.S. 62-133.9(d) and Rules R8-68 and R8-69.

The Commission believes that the decision on the issue of incentives is by nature a balancing act. The incentives should not be excessive, but they must be sufficient to motivate the Company to deploy DSM and EE programs effectively and aggressively. The Stipulating Parties have demonstrated that the modified save-a-watt approach strikes the right balance between incentivizing the Company to pursue DSM and EE and protecting customers' interests in fair rates. Moreover, the Agreement provides increased energy savings for customers, while offering a fair earnings opportunity for investments in DSM and EE. Further, the Agreement creates greater transparency to the Company's earnings opportunity by making lost revenues a direct recovery component of the rider and true-up calculations. Finally, there are performance targets tied to earnings caps that will ensure the Company's profits are just and reasonable. The Commission therefore concludes that the Settlement Agreement is in the public interest and should be accepted by the Commission as a fair and reasonable resolution of the issues in this proceeding.

IT IS, THEREFORE, ORDERED as follows:

ELECTRIC – MISCELLANEOUS

1. That the Settlement Agreement and Joint Stipulation filed by Duke, the Environmental Intervenors, and the Public Staff as modified by the Commission herein, and consistent with the findings, conclusions, and decretal paragraphs as set forth in this Order, shall be, and hereby are, approved;

2. That the costs of Duke's DSM and EE programs should be allocated to the North and South Carolina retail jurisdictions, and such costs should be recovered from only the class or classes of retail customers to which the programs are targeted. No costs of any approved DSM or EE program should be allocated to the wholesale jurisdiction. The reduced energy consumption resulting from the implementation of EE measures, or EE RECs, thus paid for by Duke's retail customers should be used solely for Duke's REPS compliance obligation;

3. That Paragraph G of the Settlement Agreement shall be, and hereby is, modified to read as follows:

G. Net Lost Revenues

1. Net lost revenues mean revenue losses, net of marginal costs avoided at the time of the lost kilowatt-hour sale(s), incurred by the Company's public utility operation as the result of a new energy efficiency measure. Net lost revenues shall also be net of any increases in revenues resulting from any activity by the Company's public utility operations that cause a customer to increase demand or energy consumption, whether or not that activity has been approved pursuant to R8-68. Programs or measures with the primary purpose of promoting general awareness and education of energy efficiency as well as research and development activities are ineligible for the recovery of net lost revenues. Pilot programs or measures are also ineligible for the recovery of net lost revenues, unless the Commission approves the Company's specific request that a pilot program or measure be eligible for the recovery of net lost revenues when the Company seeks approval of that pilot program or measure. Utility activities shall be closely monitored by the Company to determine if they are causing a customer to increase demand or consumption, and the Company shall identify and keep track of all of its activities that cause customers to increase demand or consumption, whether or not those activities are associated with demand-side management or energy efficiency programs, as provided in the Settlement Agreement, so that they may be evaluated by the parties and the Commission for possible confirmation as "found revenues." When authorized by Commission Rule R8-69, and unless the Commission determines otherwise in a G.S. 62-133.9 DSM/EE rider proceeding, net lost revenues shall be recovered for 36 months for each vintage year, except that the recovery of net lost revenues will end upon Commission approval of (1) an alternative recovery mechanism, or (2) 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;

4. That Duke and the Public Staff shall be, and hereby are, requested to work cooperatively to develop practices and procedures which will ensure, to the maximum extent

possible, that the Company is able to identify and keep track of all its activities that cause customers to increase demand or consumption, whether or not those activities are associated with demand-side management or energy efficiency programs, so that they may be evaluated by the parties and the Commission for possible confirmation as "found revenues;"

5. That the Settlement Agreement, as approved in this Order, shall be, and hereby is, deemed sufficient to support deferral accounting for North Carolina jurisdictional regulatory purposes;

6. That Duke shall be, and hereby is, 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 and Account 254 – Other Regulatory Liabilities;

7. That Duke shall be, and hereby is, required (1) to include all actual program revenues (estimated, if not known) and only actual program costs (estimated, if not known) for purposes of calculating and presenting its regulated earnings to the Commission for NCUC ES-1 purposes; (2) to provide supplementary schedules setting forth the Company's jurisdictional earnings excluding the effects of EE and DSM programs; and (3) to provide schedules separately stating the earnings impact of its DSM and EE programs on a combined basis as well as on a stand-alone, program-class basis, that is, with earnings from DSM programs, collectively, and earnings from EE programs, collectively, shown separately. Detailed calculations of the foregoing shall also be provided. Such schedules and/or calculations shall show, at a minimum, actual revenues; expenses; taxes; operating income; investment base, including major components where applicable; and applicable capitalization ratios and cost rates, including overall rate of return and return on common equity. Net lost revenues realized (estimated, if not known) for each reporting period shall be clearly disclosed as supplemental information;

8. That Duke shall be, and hereby is, required to direct the Advisory Group in studying the feasibility of expanding programs for low-income customers and, to the extent found appropriate, shall file such additional programs for Commission approval;

9. That Duke shall be, and hereby is, required to address, update, and revise, as appropriate, information and tables presented in the Company's September 1, 2009 IRP report, in Docket No. E-100, Sub 124, to reflect information as approved in this Order, as part of its direct testimony filing in the IRP docket; and

10. That the time for filing appeal of the Notice of Decision, issued December 14, 2009, shall run from the date of this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 9th day of February, 2010.

THE NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

kh020910.01

DOCKET NO. E-7, SUB 941

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 CUSTOMER NOTICE PROPOSAL

HEARD IN: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina on Tuesday, June 8, 2010.

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

APPEARANCES:

For Duke Energy Carolinas, LLC:

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Molly L. McIntosh, K&L Gates, LLP, 214 North Tryon, 47th Floor, Charlotte, North Carolina 28202

For the Using and Consuming Public:

Kendrick C. Fentress, 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: G.S. 62-133.9(d) authorizes the 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 and energy efficiency (DSM/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 rider (DSM/EE 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.

In this present proceeding, Docket No. E-7, Sub 941, Duke Energy Carolinas, LLC (Duke Energy Carolinas or the Company) has requested that the Commission approve its next proposed DSM/EE cost recovery rider. Furthermore, two other dockets, Docket No. E-7, Sub 831 and Docket No. E-7, Sub 938, have resulted in Commission orders setting forth certain rulings and findings which are pertinent to matters now being addressed in this present proceeding. Therefore, a very brief overview of relevant matters addressed in those other two dockets is first provided below.

Docket No. E-7, Sub 831
Save-A-Watt and DSM/EE Rider Proceeding

On February 9, 2010, in Docket No. E-7, Sub 831, the Commission issued its *Order Approving Agreement and Joint Stipulation of Settlement Subject to Certain Commission-Required Modifications and Decisions on Contested Issues* (Sub 831 Order), regarding Duke Energy Carolinas' first DSM/EE rider proceeding. In the Sub 831 Order, the Commission approved a modified save-a-watt approach, a four-year limited term pilot. In the present proceeding, Docket No. E-7, Sub 941, Duke Energy Carolinas utilized such modified save-a-watt approach in its application whereby the revenue requirements underlying its proposed DSM/EE riders are based upon percentages of avoided costs, plus compensation for net lost revenues resulting from EE programs only.[1]

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, and the Southern Alliance for Clean Energy, the Environmental Defense Fund, the Natural Resources Defense Council, and the Southern Environmental Law Center (Settlement).

On March 10, 2010, Duke Energy Carolinas filed a motion for clarification and reconsideration regarding certain decisions made by the Commission in the Sub 831 Order. The request for clarification and reconsideration involved the Commission's modifications of Section G, the "Net Lost Revenues" section, of the Settlement. Among other things, the Company requested clarification and reconsideration of the requirement that Duke Energy Carolinas identify and track its activities that cause a customer to increase demand or energy consumption, whether or not that activity has been approved as a DSM or EE program, so that they may be

[1] The Agreement and Joint Stipulation of Settlement included as Schultz Settlement Exhibit No. 1 attached to the settlement testimony of Duke Energy Carolinas witness Theodore E. Schultz in Docket No. E-7, Sub 831, erroneously did not reflect the stipulating parties' intent that the recovery of net lost revenues was limited to those resulting from EE programs only. However, Duke Energy Carolinas witness Stephen M. Farmer stated on Page 15, Lines 8-9, of his settlement testimony in Docket No. E-7, Sub 831 that "[t]he calculation of net lost revenues does not apply to demand-side management programs". Consequently, in the Sub 831 Order, the Commission corrected such error and expressly limited the recovery of net lost revenues to those associated with EE programs.

evaluated for possible confirmation as "found revenues." On April 6, 2010, the Commission issued an *Order Allowing Comments* on the Company's motion for clarification and reconsideration. The Commission received comments and reply comments, and issued an *Order Denying Motion for Clarification and Reconsideration* on July 7, 2010 (Reconsideration Order).

Docket No. E-7, Sub 938
Waiver of Rules R8-69 (a)(4), (a)(5), (d)(3), and (e)(2) Proceeding

On February 15, 2010, the Company filed an Application for Waiver of Commission Rule R8-69 in Docket No. E-7, Sub 938 (Waiver Application), requesting, in part, waiver of Commission Rule R8-69(d)(3) so that it may permit qualifying commercial and industrial customers to opt out of the DSM and/or EE portion of Rider EE.[1]

Under the Waiver Application, the initial opt-out election for both DSM and EE programs would occur during the 60 days beginning June 15, 2010. If a customer opts into a DSM program, it would be required to participate for three years in the approved save-a-watt DSM programs and rider. If a customer chooses to participate in an EE program, that customer would be required to pay the EE-related avoided cost revenue requirements and the net lost revenues for the corresponding vintage year of the programs in which it participated. Customers that opt out of the Company's DSM and/or EE programs would remain opted-out for the term of the save-a-watt pilot, unless they choose to opt back in during any of the succeeding annual election periods, which occur from November 1 to December 31 each year, the 60-day period preceding the start of the Rider EE rate period as proposed by the Company.

The Company also requested waiver of Commission Rules R8-69(a)(4) and R8-69(a)(5) regarding the definitions of rate period and test period. Under the modified save-a-watt approach, 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 the 12-month period in which a specific DSM or EE measure is installed for an individual participant or group of participants.[2] 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. Consistent with the Waiver Application, the Company calculated its presently proposed Rider EE using the rate period January 1, 2011 through December 31, 2011.

Pursuant to the Waiver Application, "test period" is defined as the most recently completed vintage year at the time of the Company's DSM/EE rider application filing date. As a result, the present filing for Rider EE does not include an EMF component for Vintage Year 1 because Vintage Year 1 has not been completed as of the filing date. Instead, the Company

[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.

[2] Vintage Year 1 is an exception in terms of length. Vintage Year 1 is a 19-month period beginning June 2009 and ending December 2010, as a result of the approval of save-a-watt programs prior to the approval of the cost recovery mechanism.

proposed that an EMF component for Vintage Year 1 will be filed in the next annual proceeding in 2011.

On February 24, 2010, 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 it to the extent that a customer that has not actually participated in a DSM or EE program is required to pay any portion of the DSM/EE rider after it has opted out. The Commission also 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 DSM/EE EMF rider may incorporate adjustments for multiple test periods. Also on May 6, 2010, the Public Staff filed a motion for clarification or, in the alternative, for reconsideration, requesting that the Commission reconsider the exemption of customers that have not actually participated in a DSM or EE program from payment of any portion of the DSM/EE rider after they have opted out.

The Commission issued an *Order on Motions for Reconsideration* on June 3, 2010 (Second Waiver Order), denying the Public Staff's motion and 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. 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 Rule R8-69(b)(1)[1].

Docket No. E-7, Sub 941
Present DSM/EE Rider Proceeding

On March 2, 2010, Duke Energy Carolinas filed a motion for extension of time to file its application for approval of a DSM/EE cost recovery rider and accompanying testimony and exhibits. On March 5, 2010, the Commission issued an *Order Granting Extension of Time*.

On March 5, 2010, pursuant to G.S. 62-133.9 and Commission Rule R8-69, Duke Energy Carolinas filed an application for approval of a DSM/EE cost recovery rider (Rider EE) for Vintage Year 2 (the Application). Concurrently with the Application, the Company filed the direct testimony and exhibits of Jane L. McManeus, Director of Rates for Duke Energy

[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.

Carolinas, and Timothy Duff, General Manager of Retail, Customer and Regulatory Strategy for Duke Energy Corporation.

On April 6, 2010, the Attorney General filed a notice of intervention, which is recognized pursuant to G.S. 62-20. The intervention of the Public Staff is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

On April 9, 2010, the Commission issued an Order scheduling a hearing for June 8, 2010, establishing discovery guidelines, providing for intervention and testimony by other parties, and stating that a public notice would be approved by further order.

On April 22, 2010, Carolina Utility Customers Association, Inc. (CUCA) filed a petition to intervene, which was granted by the Commission on April 28, 2010.

On April 28, 2010, the Commission issued an *Order Requiring Public Notice*.

On May 21, 2010, the Public Staff filed a motion for extension of time which was granted on that same date.

On May 27, 2010, the Public Staff filed the affidavits of Jack L. Floyd, Electric Engineer in the Electric Division of the Public Staff, and Michael C. Maness, Assistant Director of the Accounting Division of the Public Staff.

On June 4, 2010 and June 17, 2010, the Company filed its affidavits of publication of the required notices of the proceeding.

The hearing was held as scheduled on June 8, 2010, in Raleigh, North Carolina. No customers presented testimony at the hearing.

On July 1, 2010, Duke Energy Carolinas filed a motion for extension of time to file briefs and proposed orders, which was granted on July 2, 2010.

On July 14, 2010, the Public Staff and Duke Energy Carolinas filed a Joint Proposed Order.

Based upon consideration of Duke Energy Carolinas' application, the pleadings, 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 AND CONCLUSIONS

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 rate period for purposes of this proceeding is January 1, 2011 through December 31, 2011.

4. Pursuant to the Commission's Second Waiver Order, the test period for Rider EE is the most recently completed vintage year at the time of the Company's Rider EE cost recovery application filing date. Consequently, Rider EE does not include an EMF component for Vintage Year 1 because Vintage Year 1 has not been completed as of the Company's filing date. Instead, it is appropriate for the Company to file an EMF component for Vintage Year 1 in the next annual DSM/EE rider proceeding in 2011.

5. Duke Energy Carolinas has calculated its proposed rates for Rider EE, which include the estimated avoided cost revenue requirements for Vintage Year 2 DSM programs, the estimated avoided cost revenue requirements and the first year of net lost revenues for Vintage Year 2 EE programs, and the second year of estimated net lost revenues for Vintage Year 1 EE programs 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. The Commission finds and concludes that Rider EE and the associated billing factors should be approved, in light of the evidence presented, subject to appropriate true-ups in future cost recovery proceedings consistent with the Settlement, the Sub 831 Order, and the Second Waiver Order.

6. The reasonable and prudent Rider EE billing factor for <u>residential</u> customers is 0.1702 cents per kilowatt-hour (kWh) (including gross receipts tax and regulatory fee). It is appropriate to charge such billing factor to all North Carolina retail residential customers served during the rate period January 1, 2011 through December 31, 2011.

7. The reasonable and prudent Rider EE billing factor for <u>nonresidential</u> customers who participated in <u>Vintage Year 1</u> is 0.0031 cents per kWh (including gross receipts tax and regulatory fee). It is appropriate to charge such billing factor to all North Carolina retail nonresidential customers served during the rate period January 1, 2011 through December 31, 2011, who participated in a DSM or EE program during Vintage Year 1.

8. The reasonable and prudent Rider EE billing factor for <u>nonresidential</u> customers who elect to participate in <u>Vintage Year 2</u> of the Company's <u>EE programs</u> is 0.0257 cents per kWh (including gross receipts tax and regulatory fee). It is appropriate to charge such billing factor to all North Carolina retail nonresidential customers served during the rate period January 1, 2011 through December 31, 2011, who do not opt out of the Company's EE programs for Vintage Year 2.

9. The reasonable and prudent Rider EE billing factor for nonresidential customers who elect to participate in Vintage Year 2 of the Company's DSM programs is 0.0297 cents per kWh (including gross receipts tax and regulatory fee). It is appropriate to charge such billing factor to all North Carolina retail nonresidential customers served during the rate period January 1, 2011 through December 31, 2011, who do not opt out of the Company's DSM programs for Vintage Year 2.

EVIDENCE FOR FINDINGS OF FACT AND CONCLUSIONS NOS. 1 AND 2

The evidence in support of these findings of fact and conclusions can be found in the Application, the testimony and exhibits in this docket, and the statutes, case law, and rules governing the authority and jurisdiction of this Commission. These findings 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 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. 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." 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 approach 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 of avoided capacity costs and avoided energy costs achieved by EE measures. In addition, the modified save-a-watt approach 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 FOR FINDINGS OF FACT AND CONCLUSIONS NOS. 3 AND 4

The evidence in support of these findings of fact and conclusions can be found in the Second Waiver Order (Docket No. E-7, Sub 938) and in the testimony of Company witnesses McManeus and Duff. The rate period and the absence 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. Further, the Second Waiver Order required that Duke Energy Carolinas true up all costs of its save-a-watt pilot through the DSM/EE EMF rider described in Rule R8-69(b)(1). Such true-up will begin to occur when Duke Energy Carolinas files an EMF component for Vintage Year 1 in its next annual DSM/EE rider proceeding in 2011.

EVIDENCE FOR FINDINGS OF FACT AND CONCLUSIONS NOS. 5 THROUGH 9

The evidence in support of these findings of fact and conclusions can be found in the Sub 831 Order, the Application in this docket, the testimony and exhibits of Company witnesses McManeus and Duff, and the affidavits of Public Staff witnesses Maness and Floyd.

On March 5, 2010, Duke Energy Carolinas filed the 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 2.

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 approach as described in the Settlement and approved, with certain modifications, in the Sub 831 Order.

Modified Save-A-Watt Approach

The modified save-a-watt approach 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 net present value 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.[1] Initial revenue requirements are set based on 85% of targeted savings. As explained hereinabove, customer participation in the Company's DSM and EE programs, and corresponding responsibility to pay Rider EE, are determined on a vintage year basis.

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[1] 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.

The Settlement 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.

Calculation of Rider EE

Company witness McManeus described how Duke Energy Carolinas calculated its Rider EE in accordance with the modified save-a-watt approach. Witness McManeus testified that the estimated revenue requirements for Vintage Year 2 are determined separately for residential and nonresidential 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 approach, 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 net present value of estimated avoided capacity and energy costs applicable to EE programs, as well as estimated net lost revenues for EE programs. Further, witness McManeus explained that as a result, the revenue requirements for proposed Rider EE include: (1) the avoided cost revenue requirements for Vintage Year 2 DSM programs; (2) the avoided cost revenue requirements and the first year of net lost revenues for Vintage Year 2 EE programs; and (3) the second year of net lost revenues for Vintage Year 1 EE programs.

McManeus Exhibit 1 demonstrates the calculations of the residential and nonresidential 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. Witness McManeus 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 described by witness McManeus, this figure is then added to net lost revenues for the second year of Vintage Year 1 programs and net lost revenues for the first year of Vintage Year 2 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 2 to obtain the residential billing factor. Witness McManeus testified that the calculation of the nonresidential billing factors is essentially the same, using nonresidential inputs instead. However, she added, because nonresidential customers are allowed to opt out of either DSM or EE programs separately in an annual election, nonresidential billing factors have been separately computed for DSM versus EE programs and within EE programs, by vintage year.

Next, witness McManeus described how the net lost revenue component of the billing factors was determined. Witness McManeus 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

[1] Revenue requirements are set at 85% achievement of target avoided costs savings.

the estimated kW and kWh reductions applicable to EE programs. Witness McManeus 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. As shown in McManeus Exhibit 1, unless a customer did not participate in Vintage Year 1, Rider EE includes net lost revenues for the second year of Vintage Year 1 programs in addition to net lost revenues for the first year of Vintage Year 2 programs.

While Duke Energy Carolinas acknowledged that the Sub 831 Order requires that net lost revenues be net of all marginal costs actually avoided, including nonenergy-related costs, witness McManeus testified that the Company has not had sufficient time to further investigate whether any costs other than fuel and variable O&M are actually avoided, and as such, proposes to adjust net lost revenues by any additional costs found to be avoided through upcoming participation adjustments for vintage years.

Similarly, witness McManeus pointed out that given the recency of the Sub 831 Order, Duke Energy Carolinas has not had the opportunity to identify and track utility activities in the manner prescribed by the Commission in order for evaluation of "found revenues" in this proceeding. Moreover, in the Reconsideration Order, issued July 7, 2010, in Docket No. E-7, Sub 831, the Commission directed the Public Staff to meet with Duke Energy Carolinas, as expeditiously as possible, to discuss identifying and tracking the Company's activities, and report the results of such meeting(s) to the Commission no later than November 4, 2010.

Given that the Sub 831 Order was issued February 9, 2010, the Reconsideration Order was issued July 7, 2010, and Duke Energy Carolinas had to file its Application on March 5, 2010, it is understandable that the Company has not been able to investigate and incorporate these two aspects of the Sub 831 Order into its net lost revenue calculations for Rider EE. Further, the Sub 831 Order requires Duke Energy Carolinas to determine nonenergy-related costs avoided (if any), at the latest, under the true-up and measurement and verification provisions of the Settlement. Therefore, the Company's proposal to wait to adjust net lost revenues by any nonenergy-related costs found to be avoided until upcoming participation true-ups is appropriate and consistent with the Sub 831 Order. Likewise, once a method for identifying and tracking Duke Energy Carolinas' activities is developed, any found revenues will be incorporated into the true-up process and reflected appropriately in future estimates.

Witness McManeus also provided testimony regarding allocation of the revenue requirements for Rider EE. In particular, witness McManeus explained that the revenue requirements for EE programs targeted at residential customers across North Carolina and South Carolina are allocated to the North Carolina retail jurisdiction based on the ratio of North Carolina retail kWh sales to system retail kWh sales, and then recovered only from North Carolina residential customers. The revenue requirements for EE programs targeted at nonresidential customers across North Carolina and South Carolina are allocated to the North Carolina retail jurisdiction based on the ratio of North Carolina retail kWh sales to system retail kWh sales, and then recovered from only North Carolina retail nonresidential customers.

According to witness McManeus, the revenue requirements for all retail DSM programs targeted at both residential and nonresidential customers across North Carolina and South Carolina are allocated to the North Carolina retail jurisdiction based on the North Carolina retail contribution to retail system peak demand. The North Carolina retail revenue requirements are then allocated between residential and nonresidential customers based on each group's contribution to the North Carolina retail peak demand.

No party disputed the Company's allocation of revenue requirements for Rider EE, as described by witness McManeus, and such allocation is consistent with the method adopted by the Commission in the Sub 831 Order.

Company witness Duff testified that Duke Energy Carolinas does not have the ability to adjust sales or demand for Rider EE to take into account the impact of opt-out customers because there has been no election period related to Vintage Year 2 yet. Witness Duff added that although the Company has completed enrollment periods for Vintage Year 1, the Waiver Order creates the need to conduct another enrollment for Vintage Year 1 to allow customers that may have previously opted out under the original election criteria to opt in under the new criteria. As a result, the Company believes that the information currently known regarding Vintage Year 1 opt-out elections is not useful as an estimate for Vintage Year 2 elections. Instead, the Company proposes to reflect the actual opt-out results for Vintage Year 2 in the associated participation true-up.

Public Staff witness Floyd testified that the Public Staff agreed that determining the significance and impact of the Commission's Waiver Order, issued in Docket No. E-7, Sub 938, and the upcoming election period on Duke Energy Carolinas' proposed Rider EE for Vintage Year 2 is difficult at this time. The Public Staff further agreed that the impacts from actual opt-outs will be reflected in the participation true-up for Vintage Year 2. Therefore, the Public Staff did not recommend any adjustments reflecting the impacts from opt-outs to Vintage Year 1 or Vintage Year 2 in this proceeding.

No party has presented any evidence that Duke Energy Carolinas should be required to adjust sales and demand to reflect impacts from opt-out customers now, as opposed to in the associated participation true-up.

Given that due to the Waiver Order and the Second Waiver Order, the current opt-out characteristics for Vintage Year 1 may not reflect the opt-out characteristics for Vintage Year 2, and that the enrollment period for Vintage Year 2 has not yet commenced, the Commission believes that it is reasonable for the Company to exclude the opt-out impacts for the purpose of calculating Rider EE, and instead reflect the actual opt-out elections of customers in the associated participation true-ups for Vintage Year 1 and Vintage Year 2.

Public Staff witness Maness testified that during the course of the Public Staff's investigation in Docket No. E-7, Sub 831, the negotiation of the Settlement, and the development of the rates resulting from the Settlement, the Company provided the Public Staff with detailed inputs and calculations underlying the determination of the estimated revenue requirements over the four-year pilot period, as eventually summarized on Exhibit 3 to Company witness Stephen M. Farmer's settlement testimony in Docket No. E-7, Sub 831 (Farmer Settlement Exhibit 3).

Witness Maness explained that these calculations supported both the calculation of the rates proposed, and eventually approved, in Docket No. E-7, Sub 831, as well as the target avoided cost savings for the four-year period set forth in the Settlement. Witness Maness testified that his review of the Company's proposed Rider EE in this proceeding reveals that the revenue requirements and resulting rates proposed by the Company have been calculated using essentially the same inputs and methods as were provided to the Public Staff during the Docket No. E-7, Sub 831 proceeding, except for certain items set forth in the testimony of Company witness McManeus, as noted below. In other words, the revenue requirements calculated by the Company in this proceeding for Vintage Year 2 are essentially the same as those estimated for Vintage Year 2 at the time of the Settlement and the Sub 831 Order.

Further, witness Maness explained that because no true-up is being proposed in this proceeding, and the fact that the four-year pilot is still in its relatively early stages, the Public Staff agrees with the utilization of the Sub 831 estimates to calculate the prospective rates for Vintage Year 2. Witness Maness noted that the Vintage Year 2 rates, as well as those charged during Vintage Year 1, remain subject to both interim and final true-ups throughout and following the four-year term; no final rate is being set in this proceeding.

Company witness McManeus testified that the proposed Rider EE revises the estimated rider contained in Farmer Settlement Exhibit 3 by updating the projected North Carolina retail kWh sales to reflect the latest available sales forecast (Fall 2009); updating the Company's calculations of net lost revenues to subtract variable O&M; correcting an error in applying gross receipts taxes to net lost revenues; and separating nonresidential billing factors into EE and DSM components to accommodate customer elections of participation.

Public Staff witness Maness stated that the Public Staff has reviewed the changes from the Sub 831 Settlement estimates noted by Company witness McManeus, and finds them to be reasonable. Witness Maness also observed that while the Public Staff finds the unit cost utilized by the Company in this proceeding to reduce net lost revenues for variable O&M expense reasonable for purposes of the prospective rate set in this proceeding, it will continue to review variable O&M expense in future proceedings as future prospective rates and true-ups are proposed.

The Public Staff recommended approval of the Company's proposed Rider EE in this proceeding, subject to appropriate true-up in future cost recovery proceedings consistent with the Settlement, and as modified by the Sub 831 Order and other relevant orders of the Commission.

The Company's calculations of Rider EE, in accordance with the modified save-a-watt approach as described by witnesses McManeus and Maness, yield the following four billing factors, as indicated in McManeus Exhibit 1:

1. A <u>Residential</u> Rider EE of 0.1702 cents per kWh (including gross receipts tax and regulatory fee), calculated by dividing a revenue requirement of $35,378,822 by

projected rate period residential sales of 20,783,231,039 kWh. This billing factor would be charged to all North Carolina retail residential customers served during the rate period January 1, 2011 through December 31, 2011.

2. A Vintage Year 1 EE Participant Nonresidential Rider EE of 0.0031 cents per kWh (including gross receipts tax and regulatory fee), calculated by dividing a revenue requirement of $990,912 by projected rate period nonresidential sales of 32,373,648,374 kWh. This billing factor would be charged to all North Carolina retail nonresidential customers served during the rate period January 1, 2011 through December 31, 2011 who participated in a DSM or EE program during Vintage Year 1.

3. A Vintage Year 2 EE Participant Nonresidential Rider EE of 0.0257 cents per kWh (including gross receipts tax and regulatory fee), calculated by dividing a revenue requirement of $8,310,578 by projected rate period nonresidential sales of 32,373,648,374 kWh. This billing factor would be charged to all North Carolina retail nonresidential customers served during the rate period January 1, 2011 through December 31, 2011 who do not opt out of the Company's EE programs for Vintage Year 2.

4. A Vintage Year 2 DSM Participant Nonresidential Rider EE of 0.0297 cents per kWh (including gross receipts tax and regulatory fee), calculated by dividing a revenue requirement of $9,631,105 by projected rate period nonresidential sales of 32,373,648,374 kWh. This billing factor would be charged to all North Carolina retail nonresidential customers served during the rate period January 1, 2011 through December 31, 2011 who do not opt out of the Company's DSM programs for Vintage Year 2.

The Commission agrees with the uncontroverted evidence that the Company's proposed Rider EE and associated billing factors were calculated in accordance with the Settlement, as modified by the Commission, and otherwise adhere to sound ratemaking concepts and principles. Accordingly, the Commission finds and concludes, in light of the evidence presented, that the proposed Rider and associated billing factors, subject to true-up proceedings as described herein, should be approved.

Rider EE Tariff

As shown in McManeus Exhibit No. 3, Duke Energy Carolinas proposes several modifications to its existing tariff for Rider EE that correspond with the Waiver Application. Public Staff witness Floyd stated that the Company's proposed modifications generally comply with the Commission's Waiver Order. However, witness Floyd recommended that the last paragraph of the tariff for Rider EE be amended to more clearly apply only to "nonresidential" customers. Witness Floyd testified that Duke Energy Carolinas did not object to his recommendation, and, accordingly, the Company agreed to amend the last paragraph of the tariff for Rider EE to read as follows[1]:

[1] The agreed-upon changes are indicated with strike-through and underlining.

> Each factor listed under Nonresidential is applicable to ~~all~~ nonresidential customers who are not eligible to opt out and to eligible customers who have not opted out. If a nonresidential customer has opted out of a Vintage Year(s), then the charge(s) shown above for the Vintage Year(s) during which the customer has opted out, will not apply to the bill.

Based upon the foregoing, the Commission finds and concludes that Duke Energy Carolinas should amend the last paragraph of its tariff for Rider EE as recommended by witness Floyd and agreed to by the Company.

Measurement & Verification

Witness Floyd testified that the Public Staff is committed to reviewing the measurement and verification (M&V) data related to DSM and EE programs in the save-a-watt portfolio each year to inform the Commission about the status of M&V efforts and to highlight any potential issues that might affect future M&V evaluations, net savings, and cost recovery. Witness Floyd noted that, in reviewing Duke Energy Carolinas' M&V data provided in response to a Public Staff data request, he noticed that that TecMarket Works (the Company's third-party consultant hired to conduct M&V) made a recommendation related to the Get Energy Smart Program in the Midwest. Witness Floyd explained that like the Energy Efficiency in Schools program that Duke Energy Carolinas offers in North Carolina, the Get Energy Smart Program is a curriculum-based program where students are given kits containing various EE measures to take home. Energy savings resulting from the deployment of these measures are then used by Duke Energy Carolinas to determine its avoided cost revenue requirement from the program. According to witness Floyd, TecMarket Works appears to suggest that the Company need not adjust its savings projections based on whether the occupants of the pertinent homes are actually retail customers of Duke Energy Carolinas. The Public Staff believes that any energy savings used to reach Duke Energy Carolinas' energy savings targets under the Settlement must result directly from the actions of the Company's customers in its service area.

Witness Duff acknowledged witness Floyd's concern regarding students who take part in the Energy Efficiency in Schools program that may live outside Duke Energy Carolinas' service area; and he testified that the Company is committed to work with an industry expert to develop an appropriate allocation methodology to address such concern.

The Commission agrees with the Public Staff that any energy savings used to reach Duke Energy Carolinas' energy saving targets under the modified save-a-watt approach should result directly from the actions of the Company's customers in its service area. Accordingly, the Commission finds and concludes that Duke Energy Carolinas should file for Commission review the allocation methodology it develops to address the issue of the M&V of energy savings resulting from students who take part in the Energy Efficiency in Schools program that may live outside Duke Energy Carolinas' service area as soon as practicable, but no later than the filing date of the Company's application for initiating its 2011, DSM/EE cost recovery proceeding.

ELECTRIC – MISCELLANEOUS

Low-income Programs

Public Staff witness Floyd provided testimony regarding the Company's EE and DSM program offerings for its low-income customers. In the Sub 831 Order, the Commission ordered Duke Energy Carolinas to direct the Regional Efficiency Advisory Group (Advisory Group) to study the feasibility of expanding EE and DSM programs for low-income customers, and, as appropriate, file those programs for approval. Duke Energy Carolinas indicated in the Advisory Group meeting minutes reviewed by witness Floyd (an Advisory Group member) and in responses to verbal data requests from the Public Staff that it has sought feedback on potential low-income programs from the Advisory Group, but did not receive any suggestions. Witness Floyd testified that low-income customers in Duke Energy Carolinas' service territory already have access to the Company's existing Residential Smart Saver program, which provides CFLs to customers at minimal cost, and the Low-Income Services Program, which provides weatherization and equipment replacement assistance and kits containing EE products. Duke Energy Carolinas also reported to the Public Staff that it is reviewing additional low-income programs. Witness Floyd testified that it is his understanding that the Advisory Group will be discussing other low-income oriented DSM and EE programs in the near future.

The Commission finds and concludes that Duke Energy Carolinas should continue to work with the Advisory Group to study the feasibility of expanding DSM and EE programs for its low-income customers.

IT IS, THEREFORE, ORDERED as follows:

1. That Duke Energy Carolinas' proposed Rider EE and the associated billing factors shall be, and hereby are, approved as described herein. Such billing factors shall be in effect for the rate period January 1, 2011 through December 31, 2011.

2. That Duke Energy Carolinas shall work with the Public Staff to prepare a proposed Notice to Customers of the rate changes approved herein. The Company shall file said notice and the proposed time for service of such notice, within 30 days from the date of this Order, for Commission approval by further order.

3. That Duke Energy Carolinas shall amend the last paragraph of its tariff for Rider EE as described herein.

4. That Duke Energy Carolinas shall file for Commission review the allocation methodology it develops to address the issue of the M&V of energy savings resulting from students who take part in the Energy Efficiency in Schools program that may live outside Duke Energy Carolinas' service area as soon as practicable, but no later than the filing date of the Company's application initiating its 2011, DSM/EE cost recovery proceeding.

5. That Duke Energy Carolinas shall continue to work with the Advisory Group to study the feasibility of expanding DSM and EE programs for its low-income customers.

ISSUED BY ORDER OF THE COMMISSION.
This _3rd_ day of _August_, 2010.

THE NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

fh080310.01

DOCKET NO. E-34, SUB 38

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by New River Light & Power Company for Approval of a Rate Increase to Pass Through an Increase in the Cost of Purchased Power and for Approval of an Annual Purchased Power Cost Adjustment Procedure	)	ORDER APPROVING RATE INCREASE AND ANNUAL PROCEDURE

BY THE COMMISSION: On September 3, 2010, New River Light and Power Company (New River or the Company) filed a request with the Commission to adjust all of its base rates for usage on and after January 1, 2011, in order to pass through to its customers the increased cost of purchased power from its wholesale supplier, Blue Ridge Electric Membership Corporation (BREMCO), pursuant to a new contract dated September 1, 2010. New River stated that its current contract with BREMCO was set to expire December 31, 2010, but that it was very close to completing negotiations with BREMCO for continued purchases of power. According to New River, the new contract will result in a substantial increase in the cost of purchased power and, unlike the current contract, will also include a true-up adjustment scheduled to occur in July of each year. In the September 3 filing, New River estimated that its wholesale cost of power would increase from $10,563,964 in 2009 to $13,938,609 in 2011, based on an increase in unit purchased power costs from $0.047112 per kWh to $0.059530 per kWh (approximately 26%).

On October 21, 2010, the Company filed with the Commission, under confidential cover, an executed Electric Service Agreement (Agreement) dated September 1, 2010 between New River and BREMCO, which provides the terms, conditions, and rates associated with the wholesale purchase power agreement.

On December 15, 2010, New River filed an updated estimate of the increase in its purchased power costs, based on the finalized Agreement and the most recent estimates of 2011 costs. According to the Company's update, its estimated wholesale cost of power will increase from $10,563,964 in 2009 to $14,386,372 in 2011, based on an increase in unit purchased power costs from $0.047112 per kWh to $0.059467 per kWh (approximately 26%).

ELECTRIC – MISCELLANEOUS

New River proposes to pass through the increase in purchased power costs to its customers as a uniform across-the-board increase of $0.012782 in the per kWh charges (excluding lighting). The additional revenue produced by the purchased power cost increase to New River's customers would be the same as the additional cost of purchased power from BREMCO, adjusted for the effects of gross receipts tax and the utility regulatory fee. The proposed increase of $0.012782 per kWh will result in an increase of 15.7% in the monthly bill of an average residential customer using 1000 kWh, and in excess of 20% for representative industrial and large commercial customers.

At the Commission's Regular Staff Conference on December 20, 2010, the Public Staff stated that it had reviewed the terms, conditions, and rates associated with the Agreement, as well as New River's calculations for the increase in purchased power costs and the proposed increases in retail rates, and had determined that the proposed adjustment is consistent with previous New River pass through requests approved by the Commission. However, due to the large amount of the requested increase and the fact that New River has no approved purchased power adjustment mechanism, the Public Staff stated that it also had conducted a general review of the Company's 2009 earnings. This review included consideration of certain pro forma adjustments to normalize and annualize net operating income at December 31, 2009 levels, but was not as detailed as the review that the Public Staff would conduct in a general rate case. Based on the results of its review, the Public Staff stated that it was of the opinion that the requested pass-through increase is appropriate and reasonable in that it (a) is based solely on the increase in purchased power expense expected to be incurred by New River under the new contract, and (b) when combined with pro forma 2009 results of New River's operations, the increase does not appear to be unreasonable overall.

In its filings, New River has also requested that it be allowed to adjust its rates in January of each future year, beginning in 2012, to reflect changes in forecasted purchased power costs for that year, as well as to include an Experience Modification Factor (EMF) in its rates to true-up revenues charged for purchased power costs in the preceding year to actual purchased power costs incurred for that year. Implicit in this request is the presumption that review of the annual adjustment would not include consideration of New River's overall earnings, but would simply focus on the annual changes in the cost of purchased power.

The Public Staff also commented on this New River proposal at the December 20, 2010 Regular Staff Conference. The Public Staff stated that New River was allowed to pass through a portion of its purchased power costs for many years. Specifically, during the period 1972 through 1996, the wholesale rates charged to New River by BREMCO were typically subject to a monthly fuel or power cost adjustment, which was allowed to be automatically passed through to New River's retail customers by orders of this Commission. However, pass-through requests by New River during this period for other periodic increases in purchased power costs charged by BREMCO were subject to approval by the Commission on a case by case basis, and were also subject to evaluation of overall earnings, as appropriate. In 1996, the provision of New River's contract with BREMCO allowing for monthly adjustments in purchased power costs was eliminated, as was the allowance of monthly retail rate adjustments to pass through those changes. Since that time, all proposed pass-throughs of changes in BREMCO's purchased power rates have been subject to Commission approval and the authority of the Commission to review New River's overall earnings as part of the approval process. Additionally, during the

1972-1996 period, the Company experienced a general rate case proceeding on average every five years; whereas, it has now been 14 years since the Company's last general rate case.

The Public Staff stated that because New River has not been allowed since 1996 to utilize any sort of mechanism providing for the pass through of purchased power costs without regard to overall earnings, and has not been subject to a general rate case review in 14 years, the Public Staff does not believe it appropriate and reasonable to establish such a mechanism prior to New River's next general rate case proceeding. However, the Public Staff did recommend that the Commission establish at this time a procedure whereby New River is required to request an adjustment to its rates on an annual basis, such adjustment to include both an estimate of purchased power costs for the coming calendar year and an EMF to true up actual purchased power revenues and expenses for a preceding 12-month historical period (beginning no earlier than January 1, 2011). Such filings should be made no later than October 1 of each year, with the new rates scheduled to go into effect on January 1 of the next year. The reasonableness of any proposed rate change would remain subject to consideration of New River's overall level of earnings and return on rate base. The Public Staff also stated that based on discussions with representatives of New River, it was the Public Staff's understanding that New River does not object to the Public Staff's recommendation.

Mr. Ed Miller, General Manager of New River, appeared at the Staff Conference in support of the Company's request and the Public Staff's recommendation.

Based on the Public Staff's findings that the requested pass-through increase (a) is based solely on the increase in purchased power expense expected to be incurred by New River under the new contract, and (b) when combined with pro forma 2009 results of New River's operations, the increase does not appear to be unreasonable overall, the Commission concludes that the proposed pass-through to New River's customers of the increased cost of purchased power from its wholesale supplier should be approved without public hearing, subject to refund of any amounts subsequently found to be unjust or unreasonable upon protest and hearing, and subject to the requirements set forth in the Ordering Paragraphs below. The Commission also concludes, based on the information presented by the Company and the Public Staff, that New River should be required to request an adjustment to its rates on an annual basis, such adjustment to include both an estimate of purchased power costs for the coming calendar year and an EMF to true up actual purchased power revenues and expenses for a preceding 12-month historical period (beginning no earlier than January 1, 2011). Such filings should be made no later than October 1 of each year, with the new rates scheduled to go into effect on January 1 of the next year. The reasonableness of any proposed rate change will remain subject to consideration of New River's overall level of earnings and return on rate base.

IT IS, THEREFORE, ORDERED as follows:

1. That New River is authorized to adjust its base rates by $0.012782 per kWh effective with all usage on and after January 1, 2011, in order to pass through to its customers the increased costs of purchased power from its supplier as described herein.

2. That the rates authorized by this Order are subject to refund of any amounts which may subsequently be found unjust and unreasonable after public hearing.

3. That New River shall file copies of its approved rates, modified herein, within 10 days of the date of this Order.

4. That the Notice to the Public attached as Appendix A be mailed by separate mail or bill insert by New River to all its customers and that said Notice be mailed not later than 7 days after the date of this Order.

5. That the Notice to the Public be published by New River at its own expense in newspapers having general coverage in its North Carolina service area once a week for two consecutive weeks, the first Notice appearing not later than 7 days following the date of this Order, and said Notice covering no less than one-quarter of a page.

6. That, as set forth in this Order, New River shall file, no later than October 1 of each year, for an adjustment to its purchased power rates to be effective for the next calendar year, such adjustment to include both an estimate of purchased power costs for the coming calendar year and an EMF to true up actual purchased power revenues and expenses for a preceding 12-month historical period, taking into consideration, as appropriate, New River's overall level of earnings and return on rate base at that time.

7. That, not later than 30 days after the annual filing is made, New River shall notify its customers of the proposed change in rates, the potential impact the proposed change might have on the rates of each class of customers, and the procedure by which the proposed change is being considered by the Commission. New River shall provide notice by customer bill insert and by posting the notice on its Company website.

ISSUED BY ORDER OF THE COMMISSION.
This the 22nd day of December, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Commissioner Susan W. Rabon did not participate.

Bb122210.02

APPENDIX A
Page 1 of 2

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

NOTICE TO THE PUBLIC
DOCKET NO. E-34, SUB 38
BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

NOTICE IS HEREBY GIVEN that New River Light & Power Company (New River) has requested the North Carolina Utilities Commission to approve an adjustment to its base rates for usage on and after January 1, 2011, to pass-through to its customers the increased cost of purchased power from its supplier, Blue Ridge Electric Membership Corporation (BREMCO).

The amount of the increase to New River's customers will be approximately $2,866,148 per year, an increase of approximately 18.30%. The increase will be applied to New River's customers as a uniform increase to the kilowatt-hour (kWh) energy charge (excluding lighting schedules). The additional revenue produced by the increase will be the same as the increased cost of purchased power from BREMCO, adjusted for the effects of gross receipts tax and the utility regulatory fee. The proposed increase of $0.012782 per kWh will result in an increase in the monthly bill of a residential customer using 1,000 kWh from $81.53 to $94.31. The approximate percentage increases in customers' bills, by rate schedule, are as follows (actual percentages may differ depending on specific customers' usage amounts):

Residential	15.7%
Schedule G (Commercial)	16.8%
Schedule GL (Large Commercial)	24.4%
Schedule I (Industrial)	21.5%
Schedule A (App. State Univ.)	18.9%

New River has also requested that it be allowed to adjust its rates in January of each future year, beginning in 2012, to reflect changes in forecasted purchased power costs for that year, as well as to include an Experience Modification Factor (EMF) in its rates to true-up revenues charged for purchased power costs in the preceding year to actual purchased power costs incurred for that year.

The Commission has concluded that the pass-through rate adjustment requested by New River is reasonable, in that (a) it is based solely on the increase in purchased power expense expected to be incurred by New River under its contract with BREMCO, and (b) when combined with results of New River's operations, the increase does not appear to be unreasonable overall. The Commission has also approved the annual rate adjustment procedure requested by New River, subject to the proviso that it will take into consideration, as appropriate, New River's overall level of earnings and return on rate base at the time of each annual filing.

APPENDIX A
Page 2 of 2

Therefore, the Commission has approved New River's requests without public hearing, subject to refund of any amounts which may subsequently be found to be unjust or unreasonable after any public hearing in this matter that may be held by the Commission, as described below.

Persons desiring to intervene in this matter as formal parties of record should file a motion under Commission Rules R1-6, R1-7, and R1-19 not later than 45 days after the date of this notice. Persons desiring to present testimony or evidence at a hearing should so advise the Commission. Persons desiring to send written statements to inform the Commission of their positions in the matter should address their statements to Chief Clerk, North Carolina Utilities Commission, 4325 Mail Service Center, Raleigh, North Carolina 27699-4325. However, such written statements cannot be considered competent evidence unless those persons appear at a public hearing and testify concerning the information contained in their written statements. If a significant number of requests for a public hearing are received within 45 days after the date of this notice, the Commission may schedule a public hearing.

The Public Staff is authorized by statute to represent the interests of the using and consuming public in proceedings before the Commission. Written statements to the Public Staff should include any information which the writers wish to be considered by the Public Staff in its investigation of the matter, and such statements should be addressed to Robert P. Gruber, Executive Director, Public Staff, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326.

ISSUED BY ORDER OF THE COMMISSION.
This the 22nd day of December, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

DOCKET NO. E-22, SUB 459
DOCKET NO. E-22, SUB 461

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-22, SUB 459 In the Matter of Application of Dominion North Carolina Power for an Increase in and Revisions to Its Rates and Charges Applicable to Electric Utility Service in North Carolina and DOCKET NO. E-22, SUB 461 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	)	ORDER GRANTING GENERAL RATE INCREASE, APPROVING FUEL CHARGE ADJUSTMENT, AND APPROVING STIPULATION AND SUPPLEMENTAL AGREEMENT

HEARD: Tuesday, August 31, 2010, at 7:00 p.m., in Williamston City Hall, Assembly Room, Second Floor, 102 East Main Street, Williamston, North Carolina

Wednesday, September 1, 2010, at 7:00 p.m., Dare County Justice Center, Courtroom A, 962 Marshall C. Collins Drive, Manteo, North Carolina

Thursday, September 2, 2010, at 7:00 p.m., in the Pasquotank County Courthouse B, 206 East Main Street, Elizabeth City, North Carolina

Wednesday, September 8, 2010, at 7:00 p.m., in the J. Reuben Daniel City Hall and Police Station, Conference Room, 1040 Roanoke Avenue, Roanoke Rapids, North Carolina

Tuesday, October 12, 2010, at 9:00 a.m., Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

Thursday, October 14, 2010, at 9:30 a.m., 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

ELECTRIC – RATE INCREASE

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

Bernard L. McNamee, II, and Joseph K. Reid, III, McGuire Woods, LLP, One James Center, 901 East Cary Street, Richmond, Virginia 23219

Horace P. Payne, Jr., Senior Counsel, Dominion Resources Services, Inc., Law Department, 120 Tredegar Street, Riverside 2, Richmond, Virginia 23219

For Carolina Industrial Group for Fair Utility Rates I:

Ralph McDonald, Bailey and Dixon, L.L.P., Post Office Box 1351, Raleigh, North Carolina 27602

For Nucor Steel-Hertford:

Damon E. Xenopoulos, Brickfield, Burchette, Ritts & Stone, P.C., 1025 Thomas Jefferson Street, N.W., 8th Floor, West Tower, Washington, D.C. 20007

Christopher J. Blake, Nelson, Mullins, Riley & Scarborough, LLP, 4140 ParkLake Avenue, Suite 200, Post Office Box 30519, Raleigh, North Carolina 27622-0519

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 16, 2009, Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (DNCP or Company), gave notice pursuant to Commission Rule R1-17(a) of its intent to file a general rate case application. On November 30, 2009, December 8, 2009, and January 11, 2010, DNCP filed revised notices of intent to file a general rate case application.

On February 15, 2010, DNCP filed its application requesting authority to adjust and increase its rates for retail electric service in North Carolina effective on April 15, 2010. DNCP proposed a non-fuel base rate increase of $29.4 million and a fuel rate increase of $16.7 million, for a total of $46.1 million, using a test period consisting of the 12 months ended December 31, 2008, updated by estimates of changes in rate base, revenues, and expenses through June 30, 2010. DNCP agreed in its application to work with the Public Staff-North Carolina Utilities Commission (Public Staff) to limit its update to an earlier period if necessary for the Public Staff to complete its audit. DNCP also (1) recommended that its rate case application be consolidated with its annual fuel charge adjustment proceeding and requested that the start of the rate case evidentiary hearing be delayed until October 2010, and (2) agreed to waive its right under G.S. 62-135 to put the suspended rates into effect under bond upon the expiration of six months from April 15, 2010, as well as the dates provided by Commission Rule R8-55 for the fuel charge adjustment proceeding. In exchange, DNCP requested that the Commission issue a final order for both the general rate case and the fuel charge adjustment proceeding so that new rates resulting from both proceedings would be effective January 1, 2011.

Also on February 15, 2010, DNCP filed the direct testimony and exhibits of Paul D. Koonce, President and Chief Operating Officer for the Company; James H. Vander Weide, Research Professor of Finance and Economics at Duke University's Fuqua School of Business and President of Financial Strategy Associates; G. Scott Hetzer, Senior Vice President – Tax and Treasurer for the Company; M. Stuart Bolton, Jr., Senior Vice President – Regulatory Accounting for the Company; Andrew J. Evans, Managing Director – Cost Allocation and Policy for Dominion Resources Services, Inc.; David F. Koogler, Director – Regulatory and Pricing for the Company; Diane G. Leopold, Senior Vice President – Business Development and Generation Construction for the Company; Gregory J. Morgan, Managing Director – Energy Supply for the Company; and Glenn A. Kelly, Director of Generation System Planning for the Company.

Petitions to intervene were filed by the Carolina Industrial Group for Fair Utility Rates I (CIGFUR) on November 18, 2009; by Nucor Steel-Hertford (Nucor), a division of Nucor Corporation, on February 15, 2010; and by the Carolina Utility Customers Association, Inc. (CUCA), on September 1, 2010. All such petitions were granted by the Commission. The Attorney General gave notice of intervention on November 25, 2009. The Public Staff's intervention was recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

On April 7, 2010, the Commission issued its Order Establishing General Rate Case, Suspending Rates, Scheduling Hearings, Requiring Public Notice, and Consolidating Proceedings. The Commission declared the Company's application to be a general rate case pursuant to G.S. 62 137 and suspended the proposed rates until January 1, 2011; required DNCP to waive its right under G.S. 62-135 to put the suspended rates into effect under bond upon the expiration of six months from April 15, 2010; consolidated the rate case and the fuel charge adjustment proceeding; waived the dates provided by Commission Rule R8-55 for the fuel charge adjustment proceeding; established deadlines for the filing of petitions to intervene and testimony; established appropriate discovery rules; required public notice; and stated that a separate public notice would be required after DNCP filed its fuel charge adjustment application in August 2010.

On April 28, 2010, DNCP filed a motion for Alexander N. Bailey, Manager Regulation – Regulatory Accounting Department for Dominion Resources Services, Inc., to adopt the prefiled testimony of M. Stuart Bolton, Jr., which was granted by an Order issued on May 6, 2010. Subsequently, on May 18, 2010, DNCP filed the Supplemental Testimony of David F. Koogler.

On July 30, 2010, DNCP filed a supplemental application, testimony, and exhibits pursuant to G.S. 62-110.6, providing additional testimony and information with respect to the need, estimated construction costs, and estimated construction schedule for certain out-of-state generating facilities. In support of the Virginia City Hybrid Energy Center (VCHEC), the Company filed the Supplemental Direct Testimony and Exhibits of Mark D. Mitchell, Director – Fossil and Hydro Construction for the Company; M. Masood Ahmad, Director of Integrated Resource Planning for the Company; Glenn A. Kelly; Alexander N. Bailey; Gregory A. Workman, Director – Fuels for the Company; and Sidney J. Bragg, Director of Fossil and Hydro Operations for the Company. In support of the Bear Garden generating facility, the Company filed the Supplemental Direct Testimony and Exhibits of Robert B. McKinley, Vice President, Fossil and Hydro Generation Construction for the Company; M. Masood Ahmad; Glenn A. Kelly; Alexander N. Bailey; John C. Richardson, Manager – Gas Supply Optimization for the Company; and Sidney J. Bragg. Finally, in support of the Ladysmith Units 3, 4, and 5, the Company filed the Supplemental Direct Testimony and Exhibits of Mark D. Mitchell; M. Masood Ahmad; Glenn A. Kelly; Alexander N. Bailey; John C. Richardson; and Sidney J. Bragg.

On August 10, 2010, the Company filed its application for an annual fuel charge adjustment proceeding in Docket No. E-22, Sub 461, along with the testimony and exhibits of Andrew J. Evans; Glenn A. Kelly; Steven M. Foust, Manager of Generation Accounting for Dominion Generation; Gregory A. Workman; Harrison H. Barker, Manager of Nuclear Fuel Procurement; and Alan L. Meekins, Director – Electric Market Operations. Also on August 10, 2010, the Company filed the Second Supplemental Testimony of David F. Koogler, now Director – Key Accounts for the Company. The purpose of witness Koogler's Second Supplemental Testimony was to reflect in DNCP's proposed base rate increase the impact of DNCP's fuel charge adjustment filing of August 10, 2010. DNCP also filed a study to show the impact of its integration into PJM Interconnection, LLC (PJM) on the North Carolina fuel charge adjustment, in compliance with Condition 1(e) of the Commission's Order Approving Transfer Subject to Conditions issued on April 19, 2005, in Docket No. E-22, Sub 418.

On August 11, 2010, the Commission issued its Order Requiring Revised and Combined Public Notice, in which it noted that DNCP, through inadvertence, had not published and mailed the notice for the Sub 459 proceeding as required by the Commission's April 7, 2010 Order. The Commission required DNCP to publish and mail a revised notice, which included notice of the general rate case in Sub 459, the fuel charge adjustment proceeding in Sub 461, and the supplemental application filed on July 30, 2010, with respect to out-of-state electric generating facilities. The Commission also rescheduled the public hearing in Roanoke Rapids to September 8, 2010.

On August 27, 2010, DNCP filed its depreciation studies and the Supplemental Testimony of Alexander N. Bailey and G. Scott Hetzer. On September 1, 2010, the Company filed the Third Supplemental Testimony of David F. Koogler.

The hearings for public witnesses were held as scheduled. The following people testified as public witnesses:

Williamston:	Maurice Gillam, Evelyn King, Vivian Gray, Gail Davender, and Eric Pearson

Manteo:	Jack Shea, Carl Woody, Vanessa Foreman, Manny Medeiros, Pam Buscemi, Warren Judge, and Virginia Tillet
Elizabeth City:	Gene Gregory, Shenice Evans, and Louise Cooper
Roanoke Rapids:	Peter Bishop, Alicia Coggin, Roberta Lynch, J. Rives Manning, Jr., Harry Harding, Martha Rowland, and Joseph Cutchin, Jr.

The majority of the testimony from the public witnesses related to the timing and magnitude of the requested rate increase and was not related to quality of service concerns.

Following several extensions of time, DNCP, the Public Staff, CIGFUR, Nucor, and CUCA (the Stipulating Parties) filed an Agreement and Stipulation of Settlement (Stipulation) on September 28, 2010. Also on September 28, 2010, DNCP and Nucor filed a Joint Notice of Contract Extension and Motion for Approval of Amended Electric Supply Agreement between DNCP and Nucor Steel-Hertford and, under seal, a proposed Amended Agreement for Electric Service between Nucor Corporation and North Carolina Power (Amended Nucor Agreement).

On September 29, 2010, the Public Staff filed the testimony of Kennie D. Ellis, an engineer in the Electric Division of the Public Staff, with respect to DNCP's need, estimated construction costs, and estimated construction schedule for VCHEC.

On October 8, 2010, the Commission issued its Order Rescheduling Hearing and Requiring Prefiled Testimony, which designated the hearing scheduled for October 12, 2010, in Raleigh for receiving public witness testimony only; rescheduled the evidentiary hearing to begin on October 14, 2010, at 9:30 a.m.; and required DNCP to prefile testimony providing a comprehensive explanation of all provisions of the settlement and answering specific questions set out in the Order.

On October 11, 2010, the Public Staff and DNCP filed their Supplemental Agreement and Stipulation of Settlement (Supplemental Stipulation). On October 12, 2010, the Public Staff filed a revised Page 4 of the Stipulation and Revised Stipulation Exhibit I, Schedule 2, Revised Stipulation Exhibit I, Schedule 2-1, and Revised Stipulation Exhibit II, Schedule 1. As required by the Commission's October 8, 2010 Order, DNCP filed on October 12, 2010, the Supplemental Testimony of Alexander N. Bailey, Andrew J. Evans, Steven M. Foust, Glenn A. Kelly, David F. Koogler, and Gregory J. Morgan and Company Joint Testimony Exhibits 1 through 8. Also on October 12, 2010, Nucor filed, under seal, on behalf of itself and DNCP, the executed Amended Nucor Agreement. On October 13, 2010, the Public Staff filed a new exhibit marked Stipulation Exhibit III, and CUCA filed a statement of position advising the Commission that it had no objection to the Supplemental Stipulation.

On October 12, 2010, the Commission held a hearing in Raleigh to receive the testimony of public witnesses. Lisa Silverthorne, Director of the Plymouth Housing Authority in Plymouth, North Carolina, testified.

On October 14, 2010, an evidentiary hearing was held in Raleigh as rescheduled. Counsel for CIGFUR and Nucor orally accepted the Supplemental Stipulation and the filed revisions to the

Stipulation. The prefiled testimony and exhibits of all DNCP witnesses and the testimony of Public Staff witness Ellis were received into evidence by agreement of the parties. DNCP presented a panel consisting of Company witnesses Bailey, Evans, Foust, Kelly, Koogler, and Morgan, who were joined by Company witness Mitchell at the request of the Commission. Following DNCP's summary of its supplemental testimony and questions by the Commission, the evidentiary hearing was adjourned and the parties were instructed to submit briefs and/or proposed orders no later than November 4, 2010.

On October 29, 2010, the Company submitted four late-filed exhibits in response to questions asked by the Commission during the evidentiary hearing. On November 4, 2010, the Public Staff, DNCP, CIGFUR, and CUCA filed a joint Proposed Order. On November 16, 2010, the Public Staff and DNCP filed some amendments to the Proposed Order relating to the Amended Agreement filed by Nucor and DNCP on September 28, 2010. On November 22, 2010, Nucor filed its statement of support for the Proposed Order submitted on November 4, 2010, as supplemented.

Based upon consideration of the verified applications, the testimony and exhibits received into evidence at the hearings, the Stipulation, as revised, the Supplemental Stipulation, the Stipulation Exhibits, as revised, and the record as a whole, the Commission now 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 the North Carolina Utilities Commission. The Company is engaged in the business of developing, generating, transmitting, distributing, and selling electric power to the public in northeastern North Carolina. DNCP has its office and principal place of business in Richmond, Virginia, and is a wholly-owned subsidiary of Dominion Resources, Inc.

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

3. DNCP is lawfully before the Commission based upon its application for a general increase in retail rates filed pursuant to G.S. 62-133 and 62-134 and Commission Rule R1-17 and based upon its application for a fuel charge adjustment filed pursuant to G.S. 62-133.2 and Commission Rule R8-55.

4. The appropriate test period for use in the general rate case proceeding in Docket No. E-22, Sub 459, is the 12-month period ended December 31, 2008, with actual changes to revenues, expenses, rate base (including construction work in progress (CWIP)), and cost of capital for the period ending the earlier of June 30, 2010, or the date by which the Public Staff could adequately complete its audit of actual data. The Company ultimately updated for revenues, expenses, capital structure, cost of capital, and rate base items through the 12 months ended March 31, 2010, except for salaries and wages and CWIP, which were updated through July 31, 2010.

5. The test period for purposes of the fuel charge adjustment proceeding in Docket No. E-22, Sub 461, is the 12 months ended June 30, 2010.

6. In its application for a general rate increase, DNCP proposed a non-fuel base rate increase of $29.4 million and a fuel rate increase of $16.7 million, for a total increase of $46.1 million, or an approximate overall increase of 14%, in its annual electric sales revenues from its North Carolina retail electric operations. The increase requested in the application resulted in an overall rate of return per DNCP of 8.98%, based upon a capital structure of 45.392% long-term debt with an embedded cost of 5.65%, 1.674% preferred stock with an embedded cost of 6.605%, and 52.934% common equity with a proposed return on equity (ROE) of 11.90%.

7. DNCP's proposal to increase the base fuel component by $16.7 million was based upon a combination of maintaining the base fuel component and Rider A as approved for billing effective January 1, 2010, and adding an increment that represents the transfer of the purchased power costs from base rates to the fuel component.

8. On August 10, 2010, DNCP filed its annual application for a change in its fuel rates. DNCP stated that it had over-recovered its test period (July 1, 2009 through June 30, 2010) fuel costs by $14,485,503 and requested a negative experience modification factor (EMF) to return those dollars to its ratepayers. In summary, the application stated that the proposed fuel cost level resulted in a decrease in fuel revenue of $28,094,956. In its application, DNCP requested approval of the following (including gross receipts tax (GRT)): a base fuel factor for residential, small general service, outdoor/street lighting, and traffic lighting of 2.886¢/kWh (kilowatt-hour); a base fuel factor for large general service, Schedule 6VP, and Schedule NS of 2.589¢/kWh; and a Rider B EMF decrement of 0.354¢/kWh for all classes.

9. Based on the pro forma number of kWh sales for the 12 months ended March 31, 2010, DNCP's August 27, 2010 supplemental general rate case and fuel case filings consisted of the following annual amounts: an increase in base non-fuel revenues of $26,744,000 and an increase in base fuel revenues of $2,386,000, for a total increase in base revenues of $29,130,000; and a decrease in EMF revenues of $30,000,000, for a total overall decrease of $870,000.

10. On September 28, 2010, the Stipulating Parties filed the Stipulation. On October 11, 2010 and October 12, 2010, respectively, the Public Staff filed the Supplemental Stipulation concerning DNCP's fuel filing and a revised Page 4 of the September 28, 2010 Stipulation with revised Stipulation Exhibits[1] on behalf of itself and DNCP. On October 13, 2010, the Public Staff filed Stipulation Exhibit III, which was an expanded version of Revised Stipulation Exhibit II, Schedule 1. All other Stipulating Parties agreed to the Supplemental Stipulation and the revisions to the Stipulation at the beginning of the evidentiary hearing on October 14, 2010. The foregoing comprehensively resolved all issues in this proceeding among all of the parties except the Attorney General, who did not raise any objections.

[1] The revised Stipulation Exhibits were identified as follows: Revised Stipulation Exhibit I, Schedule 2; Revised Stipulation Exhibit I, Schedule 2-1; and Revised Stipulation Exhibit II, Schedule 1.

11. Having carefully reviewed the Stipulation, the Supplemental Stipulation, the revised Page 4 of the Stipulation, the revised Stipulation Exhibits, the supplemental testimony filed by DNCP in compliance with the Commission's Order Rescheduling Hearing and Requiring Prefiled Testimony (Rescheduling Order) dated October 8, 2010, and all of the evidence of record, the Commission finds and concludes that the provisions of the Stipulation, as revised, and of the Supplemental Stipulation are just and reasonable to all parties under the circumstances of this proceeding and should be approved in their entirety. The specific terms of the Stipulation, as revised, and the Supplemental Stipulation are addressed in the following findings of fact and conclusions.

12. The Stipulation provides that DNCP's pro forma normalized total revenues under current rates from electricity sales for the North Carolina retail jurisdiction annualized at rates effective March 31, 2010, are $310,976,000[1] (including base non-fuel, base fuel, and Rider A, but not EMF revenues). Total revenues, when electric sales revenues are combined with other revenues assigned or allocated to the North Carolina retail jurisdiction, are $324,940,000 (not including EMF revenues), as revised on October 12, 2010. The Commission finds and concludes that these provisions of the Stipulation, as revised, are just and reasonable.

13. The Stipulation provides that present base revenues from electricity sales for the North Carolina retail jurisdiction for the 12 months ended December 31, 2008, (including $2,413,000 in miscellaneous charges, facility charges, and other revenues charged to customers) updated to include the effects of weather, customer growth, and change in usage based upon actual customer levels as of March 31, 2010, under present rates, and the non-fuel revenue increase by customer class should be as shown in the following table. The Commission finds and concludes that these updated present base revenues from electricity sales and the non-fuel revenue increases by customer class are just and reasonable in light of the evidence presented.

Customer Class	Present Non-Fuel and Fuel Base Revenues	Non-Fuel Revenue Increases	Proposed Revenues
Residential	$ 150,846,000	$ 3,723,344	$ 154,569,344
Small General Service	65,437,000	1,595,185	67,032,185
Large General Service	31,890,000	743,284	32,633,284
Schedule NS	33,521,000	1,162,624	34,683,624
Schedule 6VP	24,200,000	487,978	24,687,978
Outdoor & Street Lights	5,014,000	167,085	5,181,085
Traffic Lights	68,000	2,500	70,500
Misc., Facilities Charges, Other	2,413,000	(200,000)	2,213,000
Total NC Retail	$ 313,389,000	$ 7,682,000	$ 321,071,000

14. The Stipulation provides that the number of customers and adjusted kWh sales, as of the 12 months ended March 31, 2010, by customer class should be as shown in the following table. The Commission finds and concludes that the following number of customers and the adjusted kWh sales by customer class are just and reasonable in light of the evidence presented.

[1] This revenue number includes the effects of the migration adjustment related to the withdrawal of Rate Schedule 6 – Large General Service.

ELECTRIC – RATE INCREASE

Customer Class	Number of Customers at March 31, 2010	kWh Adjusted Through March 31, 2010
Residential	100,945	1,609,061,810
Small General Service & PA	17,250	824,858,028
Large General Service	77	495,113,015
Schedule NS	1	802,435,828
Schedule 6VP	5	409,880,846
Outdoor & Street Lights	228	24,666,055
Traffic Lights	204	588,097
Total	118,710	4,166,603,679

15. The Stipulation provides that the stipulated revenues are intended to provide DNCP, through sound management, the opportunity to earn an overall rate of return of 8.22% on a North Carolina retail jurisdictional rate base of $591,679,000 (including $72,727,000 of CWIP for VCHEC), with the return based on an embedded cost of long-term debt of 5.64%, a return on common equity of 10.70%, and a capital structure composed of 49% long-term debt and 51% common equity. As stated in the Stipulation, DNCP did not agree that the foregoing ROE and capital structure represented its anticipated or actual cost of equity or capital structure, but it accepted the resulting revenue requirement for the purpose of a global settlement of disputed issues in these proceedings.

16. The Stipulation provides for DNCP to adjust its North Carolina retail tariffs to produce an increase of $7,882,000 in non-fuel North Carolina retail annual revenues from electricity sales, which the Stipulating Parties believe represents an appropriate resolution of the contested matters in this proceeding. When combined with a reduction of $200,000 in the facilities and miscellaneous charges, the stipulated North Carolina jurisdictional non-fuel revenue increase is $7,682,000, in the general rate case. The Commission has reviewed the Stipulation's provisions for a North Carolina jurisdictional base non-fuel annual revenue increase of $7,682,000 and finds and concludes that this increase in the level of base rates and charges to be paid by DNCP's North Carolina retail customers, resulting in an overall rate of return of 8.22% on jurisdictional rate base and a return on common equity of 10.70% using a capital structure composed of 51% common equity and 49% long-term debt with an embedded cost of debt of 5.64%, are just and reasonable to all parties in consideration of all of the evidence presented.

17. Currently, DNCP recovers through the fuel charge adjustment proceedings changes in the actual fuel costs provided by the nonutility generators (NUGs) that provide such information and 70% of the changes in the net purchases from PJM. All of the capacity and energy payments made by DNCP to NUGs that do not provide actual fuel costs have been included in the non-fuel portion of the base rates and were not subject to being changed in fuel charge adjustment proceedings. DNCP proposed in its application to move the following to the fuel component of base rates: all noncapacity purchased power costs for NUGs that are subject to economic dispatch, all net purchases from PJM and other wholesale market suppliers, and all delivered renewable purchased power costs.

18. The Stipulation provides that for pro forma net market purchases of energy from PJM and other wholesale suppliers, the total market energy purchases for the 12 months ending

March 31, 2010, priced at the average for that same 12-month period, should be used. In addition, the Stipulation provides that for these net market energy purchases, 85% of the reasonable and prudent energy costs incurred during the fuel charge adjustment proceeding test period will be recovered through DNCP's fuel factor. For purposes of the general rate case, 15% of the cost of net market energy purchases during the updated test year ended March 31, 2010, was included in non-fuel base rates. The Commission finds and concludes that this aspect of the Stipulation is just and reasonable.

19. For dispatchable NUGS that provide actual fuel cost data, the Stipulation provides that, consistent with past practice, the actual fuel costs as provided by these NUGs will be recovered through DNCP's fuel factor (the base fuel rate and annual fuel charge adjustment). Currently, only Birchwood, ROVA I, and ROVA II provide actual fuel costs. The difference between the amount of their actual fuel costs and the total energy payments made by DNCP to these three NUGs as of the 12 months ended March 31, 2010, has been included in non-fuel base rates in this general rate proceeding, as have the capacity payments made by DNCP for the 12 months ended March 31, 2010. This treatment should apply to any new contracts entered into with new dispatchable NUGs for which actual fuel costs are provided. The Commission finds and concludes that this aspect of the Stipulation is just and reasonable.

20. For dispatchable NUGs that do not provide actual fuel cost data, the Stipulation provides that, for these NUGS, 85% of the reasonable and prudent energy costs incurred during the fuel charge adjustment proceeding test period will be recovered through DNCP's fuel factor. For purposes of the general rate case, 15% of the cost of energy purchases from these NUGs during the updated test year ended March 31, 2010, has been included in non-fuel base rates. Doswell Complex, Hopewell Cogeneration Facility, Cogentrix Rocky Mount, Cogentrix Richmond 1, and Cogentrix Richmond 2 are the dispatchable NUGs that do not provide actual fuel costs. If any of the foregoing five NUGs ultimately provide actual fuel cost data, then such actual fuel cost data will be used in lieu of the 85% of the energy payment mechanism. The Commission finds and concludes that this aspect of the Stipulation is just and reasonable.

21. The Stipulation provides that the 85% marketer percentage will not be subject to change until the sooner of DNCP's next general rate case or the fuel charge adjustment proceeding held in 2014 (with rates effective January 1, 2015). The present Commission cannot bind future Commissions' ratemaking decisions in the relevant DNCP fuel charge adjustment proceedings, but accepts this provision of the Stipulation subject to this condition.

22. With respect to purchases from NUGs other than the NUGs covered specifically by the Stipulation, the Stipulation provides that payments to the NUGs from which DNCP made purchases during the 12 months ended March 31, 2010, have been included in DNCP's non-fuel base rates at the expense level incurred during that 12-month period. No fuel costs relating to these NUGs will be included in fuel charge adjustment proceedings prior to DNCP's next general rate case, except that new renewable generating facilities that have registered pursuant to Commission Rule R8-66 and were not operational as of March 31, 2010, can be recovered in accordance with G.S. 62-133.2(a3), which provides that the costs described in G.S. 62-133.2(a1)(6) shall be recoverable from each class of customers as a separate component

of the rider. The Commission finds and concludes that this aspect of the Stipulation is just and reasonable.

23. The Stipulation provides that the pro forma adjustments used in the development of the revenue requirement stipulated to therein, including the level of PJM purchased power expenses, are appropriate and reasonable for purposes of this proceeding. However, the Stipulation also provides that neither the methodology utilized to calculate the levels of expense included in Docket No. E-22, Subs 459 and 461, nor the methods used by DNCP to calculate the per books PJM purchased power expense during the test years and the update period utilized in Docket No. E-22, Subs 459 and 461, shall be considered precedential. In addition, DNCP agreed to cooperate with the Public Staff in its continuing evaluations as to the appropriate treatment of PJM purchased power expenses in future general rate cases and annual fuel charge adjustment proceedings. The Commission finds and concludes that this aspect of the Stipulation is just and reasonable.

24. The Stipulation provides that, when DNCP conducts a depreciation study, it will file such study with the Commission before changing its depreciation rates, which the Commission finds and concludes, is just and reasonable. The Commission finds and concludes that the annualized amount of depreciation and amortization expense, as updated, of $36,026,000, included as an operating revenue deduction in this proceeding under the provisions of the Stipulation, and provided on Company Joint Testimony Exhibit 2 filed on October 12, 2010, is just and reasonable.

25. The Stipulation provides that the incorporation of costs associated with DNCP's Voluntary Separation Program (VSP) does not create a deferred asset, and the treatment of the VSP costs in this case was for settlement purposes only. The Commission finds and concludes that this aspect of the Stipulation is just and reasonable for purposes of this proceeding.

26. The Stipulation provides that all labor costs and corporate overheads associated with implementing and maintaining the North Carolina Renewable Energy and Energy Efficiency Portfolio Standard (REPS) program will continue to be recovered through base rates until DNCP's next general rate case. Incremental REPS costs will be recovered through a separate rider in accordance with G.S. 62-133.8(h). The Commission finds and concludes that this aspect of the Stipulation is just and reasonable.

27. G.S. 62-133.2(a3) provides that, for the costs described in G.S. 62-133.2(a1)(6), the specific component for each class of customers shall be determined by allocating these costs among customer classes based on the electric public utility's North Carolina peak demand for the prior year, as determined by the Commission, until the Commission determines how these costs shall be allocated in a general rate case for the electric public utility commenced on or after January 1, 2008. The Stipulation provides that DNCP does not have any costs to be recovered under this subsection at this time and that these costs will be allocated as provided for in the statute unless changed in DNCP's next general rate case proceeding. The Commission finds and concludes that this aspect of the Stipulation is just and reasonable.

ELECTRIC – RATE INCREASE

28. The Stipulation and Supplemental Stipulation provide that DNCP will reduce its current period fuel factor recovery (base fuel plus Rider A) by $4,623,477. The amount of the decrease results from applying the difference between the fuel factor (base plus Rider A) approved in Docket No. E-22, Sub 456, and the voltage-differentiated base fuel factors established in this general rate case proceeding to the adjusted kWh sales for the general rate case test period. The Commission finds and concludes that this aspect of the Stipulation and Supplemental Stipulation is just and reasonable.

29. Based upon the foregoing findings of fact and conclusions, it is appropriate for DNCP to adjust its North Carolina retail tariffs to produce an increase of $7,882,000 in non-fuel North Carolina retail annual revenues from electricity sales, which, when combined with a reduction of $200,000 in facilities and miscellaneous charges, produces a North Carolina jurisdictional revenue increase of $7,682,000. This will allow DNCP a reasonable opportunity to earn an overall return of 8.22%, as previously discussed herein. The Commission finds and concludes that the following amounts of operating revenues, operating revenue deductions, and original cost rate base under present base rates are appropriate and reasonable for purposes of setting rates in the general rate case proceeding: $305,872,000 of electric operating revenues, $261,685,000 of operating revenue deductions, and $591,679,000 of original cost rate base.[1]

30. The Stipulation provides that, with respect to VCHEC, which is an electric generating facility in Virginia that is intended to serve retail customers in North Carolina, DNCP has made a sufficient showing to establish the need for it, and that the estimate of the construction costs and construction schedule as set forth in the supplemental application of DNCP, filed July 30, 2010 in this docket, should be approved. The Stipulation further provides that it is appropriate to include $72,727,000 related to VCHEC as CWIP in DNCP's rate base. The Commission finds and concludes that this aspect of the Stipulation is just and reasonable.

31. The Stipulation provides that DNCP agrees to withdraw its supplemental application with respect to Bear Garden and the Ladysmith Units. It further provides that no costs related to the Bear Garden generating station are to be included in the revenue requirement, and recovery of any of the costs shall be reserved for a future proceeding. With respect to the Ladysmith Units, the Stipulation provides that the construction of these units has been completed and their inclusion in rates in this proceeding is not opposed. The Commission finds and concludes that this aspect of the Stipulation is just and reasonable.

32. DNCP based its general rate case filing on the Summer-Winter Peak and Average (SWPA) methodology for allocating revenues, operating revenue deductions, and rate base among jurisdictions and among customer classes. The Stipulation provides as follows: (a) DNCP and the Public Staff stipulated that as adjusted on a jurisdictional basis for Nucor's interruptible load, this methodology is appropriate for use in this proceeding; (b) CIGFUR and CUCA did not agree that the SWPA methodology is appropriate for allocations among customer classes either generally or under the particular circumstances of this case, but for purposes of a

[1] These stated amounts for electric operating revenues and operating revenue deductions under present rates reflect the general rate case test period fuel amounts. They do not reflect any change in electric operating revenues and operating revenue deductions related to Docket No. E-22, Sub 461, which will be subsequently addressed in this Order.

global settlement, they accepted the use of this methodology in this case; and (c) Nucor did not agree that the SWPA methodology is appropriate for allocating DNCP's fixed production costs among jurisdictions or among retail classes and did not agree that the treatment of Nucor's interruptible load in DNCP's SWPA cost studies filed in this case is appropriate; for global settlement purposes only, however, Nucor agreed with the base revenue increase assigned to Schedule NS under the revenue spread reflected in the Stipulation. The Commission finds and concludes that for purposes of this proceeding, these provisions of the Stipulation are just and reasonable.

33. The Stipulation provides that non-fuel base rates for each class should be designed to produce increases for each class in accordance with the numbers in the column labeled "Non-Fuel Revenue Increases" in the table found in Paragraph 3(A) of the Stipulation. In addition, the Stipulation provides that non-fuel base rates within each rate schedule will be increased using an "across-the-board" approach, meaning that all rates within a given rate schedule will be increased using the same percentage increase associated with the non-fuel revenue percentage increase for each respective class. The Stipulation further provides that rates should be designed in accordance with Appendix A attached to the Stipulation and that except for being adjusted for voltage differentiation, the base fuel decrease should be returned to all customer classes uniformly. The Commission finds and concludes that this allocation of the revenue increase among the rate classes is just and reasonable.

34. The Stipulation provides that DNCP's Terms and Conditions should be revised as set forth specifically in Appendix B attached to the Stipulation. The Commission finds and concludes that this aspect of the Stipulation is just and reasonable.

35. Consistent with Paragraph 10 of the Stipulation, the Commission finds and concludes that the overall quality of electric service provided by DNCP is adequate.

36. The stipulated base fuel rates were calculated on a voltage-differentiated basis, and the Stipulation provides that Rider A increments and decrements to the base fuel rates in subsequent fuel charge adjustment proceedings will be calculated on a voltage-differentiated basis, unless changed in DNCP's next general rate case. For purposes of the EMF calculation, monthly fuel costs will begin to be measured in a voltage-differentiated manner beginning January 1, 2011. The present Commission cannot bind future Commissions in future DNCP fuel charge adjustment proceedings, but accepts this part of the Stipulation subject to this condition.

37. The following fuel-related findings of fact are based on the test year for the fuel charge adjustment proceeding, which is the 12 months ended June 30, 2010. For the purpose of examining these amounts in the context of the general rate case, however, the revenues and expenses related to fuel were recalculated for the Supplemental Stipulation based upon the kWh sales for the 12 months ended December 31, 2008, updated for customer growth and changes in usage through March 31, 2010, as used in the general rate case.

38. DNCP's fuel procurement and purchasing practices during the fuel charge adjustment proceeding test period were reasonable and prudent.

ELECTRIC – RATE INCREASE

39. The per book sales on a total system basis for the fuel charge adjustment proceeding test period are 81,803,171 MWh.

40. The per book generation on a total system basis for the fuel charge adjustment proceeding test period is 85,317,720 MWh, which includes various types of generation as follows:

Generation Type	MWh
Coal	29,353,051
Combined Cycle and Combustion Turbine	7,681,552
Heavy Oil	259,487
Nuclear	26,460,787
Hydro	4,308,917
Pumped Storage (Pumping)	(3,569,414)
Power Transactions	
NUGs	7,907,000
Other	13,601,065
Sales for Resale	(684,727)

41. The nuclear capacity factor appropriate for use in the fuel charge adjustment proceeding is 94.3%, which is the estimated nuclear capacity factor for the 12 months beginning January 1, 2011.

42. The adjusted system sales on a total system basis for the fuel charge adjustment proceeding test period are 81,189,413 MWh.

43. The adjusted system generation on a total system basis for the fuel charge adjustment proceeding test period is 84,675,435 MWh, which is categorized as follows:

Generation Type	MWh
Coal	28,298,984
Combined Cycle and Combustion Turbine	7,405,720
Heavy Oil	250,176
Nuclear	27,930,058
Hydro	4,308,917
Pumped Storage (Pumping)	(3,569,414)
Power Transactions	
NUGs	7,623,072
Other	13,112,649
Sales for Resale	(684,727)

44. The appropriate fuel prices for use in the fuel part of this proceeding are as follows:

A. $31.69/MWh for coal;
B. $5.00/MWh for Surry and $5.32/MWh for North Anna – nuclear;
C. $91.01/MWh for heavy oil;
D. $43.35/MWh for combined cycle and combustion turbine fuel;
E. $28.22/MWh for NUG Power Transactions Fuel; $37.43/MWh for Purchases (@ 85%); and $28.30/MWh for Sales for Resale; and
F. A zero fuel price for hydro and pumped storage.

ELECTRIC – RATE INCREASE

45. The adjusted fuel expense on a total system basis for the fuel charge adjustment proceeding test period is $2,038,477,966.

46. The proper aggregate base fuel factor for this proceeding is 2.511¢/kWh, excluding gross receipts tax, or 2.595¢/kWh, including gross receipts tax. The Stipulating Parties agree that the fuel factor is to be differentiated by customer class based on the voltage at which service is taken. The Supplemental Stipulation provides that the voltage-differentiated fuel factors, including gross receipts tax by class, and the base fuel factors to be established in Docket No. E-22, Sub 459, are as follows:

Residential	2.623 ¢/kWh
SGS & PA	2.622 ¢/kWh
LGS	2.602 ¢/kWh
NS	2.522 ¢/kWh
6VP	2.574 ¢/kWh
Outdoor Lighting	2.623 ¢/kWh
Traffic	2.622 ¢/kWh

47. The Commission finds and concludes that the foregoing voltage-differentiated fuel factors (including gross receipts tax) by class are just and reasonable and that such fuel factors should be established as the base fuel factors in Docket No. E-22, Sub 459.

48. The Supplemental Stipulation provides that the approach approved in Docket No. E-22, Sub 456, as to the study DNCP is required to conduct for its next fuel charge adjustment proceeding to demonstrate that it has complied with Ordering Paragraph 1(e) of the Order Approving Transfer with Conditions issued April 19, 2005, in Docket No. E-22, Sub 418, should be used for the study to be conducted by DNCP for the 2011 fuel charge adjustment proceeding. The Commission finds and concludes that this aspect of the Supplemental Stipulation is reasonable and appropriate.

49. The Supplemental Stipulation provides that the appropriate North Carolina retail jurisdictional fuel expense overcollection for the fuel charge adjustment proceeding test year is $11,811,781 (including interest at 10% per annum) and that the adjusted North Carolina retail jurisdictional sales for the fuel case test year are 4,224,805 MWh. The Commission finds and concludes that these aspects of the Supplemental Stipulation are just and reasonable.

50. The Supplemental Stipulation provides that the appropriate EMF for the fuel charge adjustment proceeding is a decrement of 0.280¢/kWh, excluding gross receipts tax, or 0.289¢/kWh, including gross receipts tax, and that this EMF is to be refunded to North Carolina retail customers on a uniform basis. The Commission finds and concludes that this aspect of the Supplemental Stipulation is just and reasonable.

51. The Supplemental Stipulation provides that the final net aggregate fuel factor is 2.231¢/kWh, excluding gross receipts tax, or 2.306¢/kWh, including gross receipts tax, and further provides that the fuel factor (not including the EMF) is to be differentiated by customer class based on the voltage at which service is taken. The Supplemental Stipulation also provides

that the resulting total net voltage-differentiated fuel rates, including gross receipts tax, to be billed to DNCP's North Carolina retail customers during the 2011 fuel charge adjustment billing period are as follows:

Residential	2.334 ¢/kWh
SGS & PA	2.333 ¢/kWh
LGS	2.313 ¢/kWh
NS	2.233 ¢/kWh
6VP	2.285 ¢/kWh
Outdoor Lighting	2.334 ¢/kWh
Traffic	2.333 ¢/kWh

52. The Commission finds and concludes that the foregoing final net voltage-differentiated fuel rates are just and reasonable.

53. The Supplemental Stipulation provides that the EMF decrement on a cents-per-kWh basis was calculated using the kWh for the 12 months ending June 30, 2010, but the decrement was applied to the kWh for the 12 months ending December 31, 2008, updated for customer growth and changes in usage through March 31, 2010, for the purpose of showing a comparable revenue requirement effect, which the Commission finds to be reasonable.

54. Based upon the foregoing findings of fact and conclusions regarding the stipulated North Carolina jurisdictional non-fuel revenue increase of $7,682,000 and the stipulated fuel revenue decrease of $4,623,477, the combined result is a total base revenue increase of $3,058,523, calculated on the basis of adjusted test year sales for the year ended March 31, 2010.

55. The Stipulation provides that, effective January 1, 2011, DNCP will discontinue collecting the currently approved EMF increment and will implement an EMF decrement to refund its overcollection for the 12 months ended June 30, 2010. The Stipulation provides that the amount of this change to the EMF is $25,707,945. This amount includes the fuel test year over-recovery, but does not include interest on that over-recovery. When 10% interest is added, the current total change to the EMF is $27,291,254 (based on the kWh sales for the general rate case test year ended March 31, 2010). The Stipulation provides that the EMF over-recovery has been and should remain adjusted to change the marketer percentage for PJM net purchases from 70% to 85%. Appendix A of the Supplemental Stipulation confirmed the amounts related to the EMF. The Commission finds and concludes that this aspect of the Stipulation is just and reasonable.

56. The Supplemental Stipulation provides that the non-fuel base rates for each customer class should be designed to produce increases for each class in accordance with the provisions set forth on Appendix A, attached to the Supplemental Stipulation. The appropriate overall increase in non-fuel base revenues for the North Carolina retail jurisdiction is $7,882,000 (excluding the effect of the reduction of $200,000 in the facilities and miscellaneous charges) or 2.53%; and the percentage increases in non-fuel revenues for each customer class should be as stipulated and set forth in the Supplemental Stipulation Appendix A, at Line 6. The rates resulting

from this non-fuel revenue requirement increase will not change until DNCP's next general rate case adjustment.

57. The Supplemental Stipulation provides that the percentage changes in base revenues resulting from the addition of the stipulated decrease in base fuel revenues for each customer class should be as stipulated and set forth in the Supplemental Stipulation Appendix A, at Line 9. The stipulated fuel decrease of $4,623,477 will reduce the 2.53% non-fuel base increase to an overall 1.00% increase on a North Carolina retail jurisdictional basis. The fuel portion of the revenues is subject to change in each of DNCP's subsequent fuel charge adjustment proceedings.

58. The Supplemental Stipulation provides that the percentage change in overall revenues resulting from the non-fuel base increase, the base fuel decrease, and the decrease in EMF revenues of $27,291,254 should be distributed among customer classes as stipulated and provided in the Supplemental Stipulation Appendix A, at Line 12. The resulting overall decrease, which is a 7.37% decrease on a North Carolina retail jurisdictional basis, is appropriate. This decrease will only be in effect for the next 12 months.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1 THROUGH 5

The evidence supporting these findings of fact is contained in the verified general rate case application, the supplemental application, the fuel charge adjustment proceeding application, DNCP's NCUC Form E-1, DNCP's prefiled testimony and exhibits, the Stipulation, as revised, and the Supplemental Stipulation, and the entire record in this proceeding. These findings are informational, procedural, and jurisdictional in nature and are not contested by any party.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 6 THROUGH 10

The evidence supporting these findings of fact is contained in the verified general rate case application, the supplemental application, the fuel charge adjustment proceeding application, DNCP's NCUC Form E-1, DNCP's prefiled testimony and exhibits, the Stipulation, as revised, and the Supplemental Stipulation, and the entire record in this proceeding.

On February 15, 2010, DNCP filed its application requesting authority to adjust and increase its rates for retail electric service in North Carolina effective on April 15, 2010. DNCP proposed a non-fuel base rate increase of $29.4 million and a fuel rate increase of $16.7 million, for a total increase of $46.1 million, using a test period consisting of the 12 months ended December 31, 2008, updated by estimates of changes in rate base, revenues, and expenses through June 30, 2010. As directed by the Commission in its April 7, 2010 procedural order, DNCP worked with the Public Staff to limit the update to an earlier period. The Company and the Public Staff ultimately agreed to an update period ended March 31, 2010 (with a few updates through July 2010, such as CWIP for the Virginia City Hybrid Energy Center[1] (VCHEC)).

In support of its requested rate increase, DNCP made the following assertions: (1) that the cost of serving its North Carolina retail customers has increased substantially since it agreed to a

[1] The VCHEC is a baseload clean-coal powered electric generating facility in Virginia that will also serve retail customers in North Carolina.

five-year rate change moratorium[1] in its last general rate case in 2005, and that non-fuel base rates have not been increased since 1993; (2) that the Company has made significant investments in its generation, transmission, and distribution infrastructure over the past five years and plans to continue to make significant investments for the benefit of its North Carolina customers; and (3) that an under-recovery of purchased power costs was occurring under current rates that the Company was seeking to remedy on a going-forward basis. To remedy the asserted under-recovery of purchased power costs, the Company proposed to recover all noncapacity costs associated with purchased power subject to economic dispatch and all delivered renewable purchased power costs as part of its base fuel rate, which would be subject to adjustment in the Company's annual fuel charge adjustment proceedings.

Based on the pro forma number of kWh sales for the 12 months ended March 31, 2010, DNCP's August 27, 2010 supplemental general rate case and fuel charge adjustment filings consisted of the following annual changes: an increase in base non-fuel revenues of $26,744,000 and an increase in base fuel revenues of $2,386,000, for a total increase in base revenues of $29,130,000; and a decrease in EMF revenues of $30,000,000, for a total overall decrease of $870,000.

These findings of fact and conclusions are informational and procedural in nature and were not contested by any party.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 11 THROUGH 16

The evidence supporting these findings of fact is contained in the verified general rate case application, DNCP's NCUC Form E-1, the Company's testimony and exhibits, the Stipulation, as revised, the Company's supplemental testimony providing a comprehensive explanation of the Stipulation and responses to specific Commission questions as requested by the Commission in its October 8, 2010 Rescheduling Order, and the entire record in this proceeding.

As provided in Section 2(A) of the Stipulation and as explained in the Company's supplemental testimony, DNCP's pro forma normalized total revenues under current rates from electricity sales for the North Carolina retail jurisdiction annualized at rates effective March 31, 2010, are $310,976,000[2] (including base non-fuel, base fuel, and Rider A, but not EMF revenues). The Stipulation, as revised, shows total revenues, when electric sales revenues are combined with other revenues assigned or allocated to the North Carolina retail jurisdiction, to be $324,940,000 (not including EMF revenues). The derivation of the foregoing amounts was shown on Revised Stipulation Exhibit I, Schedule 2 filed by the Public Staff on October 12, 2010.

The Stipulation provides in Section 2(B) that DNCP should adjust its North Carolina retail tariffs to produce an increase of $7,882,000 in non-fuel North Carolina retail annual revenues from electricity sales, which the Stipulation stated represented an appropriate resolution of the contested matters in this proceeding. In addition, because the Company either proposed or agreed to

[1] The five-year rate change moratorium expired on April 15, 2010.

[2] This revenue number includes the effects of the migration adjustment related to the withdrawal of Rate Schedule 6 – Large General Service, as provided for in Appendix B, the "Terms and Conditions Settlement", attached to the Stipulation.

reductions of $200,000 in the facilities and miscellaneous charges included in the cost of service used to establish the non-fuel base revenue requirement, the agreed-upon annual electric sales revenue increase in non-fuel rates is $7,682,000.

The Company's October 12, 2010 Supplemental Testimony explained that the base rate revenues from electricity sales of $310,976,000 consist of two components. The first is the current North Carolina non-fuel base tariff rates for sales of electricity applied to an annualized and normalized level of sales based on actual North Carolina retail customers as of March 31, 2010, the result of which is approximately $198,186,000 in revenue, including a migration adjustment of $233,000 as a result of the withdrawal of Rate Schedule 6. The second component consists of the current base fuel tariff rates and Rider A applied to an annualized and normalized level of sales based on actual North Carolina retail customers as of March 31, 2010, the result of which is $112,790,000 in base fuel revenues. The Company explained that the base rate revenues do not contain EMF rate revenues; other customer revenues resulting from forfeited discounts, facility charges, miscellaneous service revenues, and load management credits; or other operating revenues used as revenue credits in the cost of service.

Additionally, the Company's October 12, 2010 Supplemental Testimony further explained how the test year operating revenues under present rates of $305,872,000, as provided in Revised Stipulation Exhibit II, Schedule 1, were derived. According to the Company, these revenues consist of four components. The first is the current North Carolina non-fuel base tariff rates for sales of electricity applied to an annualized and normalized level of sales based on actual North Carolina retail customers at March 31, 2010, the result of which, as stated in the preceding paragraph, is $198,186,000 in revenues. The second component consists of the actual fuel revenues recorded during the 2008 test period, consistent with the general rate case, inclusive of the base fuel rate, the Rider A rate, and the EMF rate, which results in base fuel revenues of $93,722,000. The third component includes other customer revenues resulting from forfeited discounts, facility charges, miscellaneous service revenues, and load management credits totaling $2,413,000 in revenues. The fourth and last component consists of other operating revenues used as revenue credits in the cost of service for the test period. These other operating revenues are $11,551,000 net of the difference between assigned and allocated load management credits.

To reconcile the differences between the base rate revenues of $310,976,000 and the operating revenues under present rates of $305,872,000, the Company presented Company Joint Testimony Exhibit 3. The reconciliation began with operating revenues under present rates and then identified changes that produce the base rate revenues. The first change, which was identified on Lines 2, 3, and 4 of Company Joint Testimony Exhibit 3, eliminated the North Carolina total fuel revenues (base fuel, Rider A, and EMF) of $93,722,000 recorded during the 2008 test period and incorporated the North Carolina fuel revenues (base fuel and Rider A) of $112,790,000 based on the current base fuel rate and Rider A applied to annualized and normalized North Carolina retail sales as of March 31, 2010. The second and last change eliminated from operating revenues under present rates the following items to derive base rate revenues: other customer revenues resulting from forfeited discounts, facility charges, miscellaneous service revenues, and load management credits of $2,413,000 and other operating revenues used as revenue credits in the 2008 cost of service study of $11,551,000 net of the difference between assigned and allocated load management credits. The Company testified that the net change of (a) updating fuel revenues and (b) eliminating other customer revenues and other operating revenues explained the difference of $5,104,000 between the two revenue amounts.

Further, the Company's October 12, 2010 Supplemental Testimony stated that it had determined that the "total revenues under present rates" included in Section 2(A) of the Stipulation needed to be revised to include the proper level of other operating revenues used as a revenue credit in the cost of service. The correct level of "total revenues under present rates" is $324,940,000 as shown on revised Page 4 of the Stipulation filed on October 12, 2010. When this correction was incorporated, the only difference between the revenue amounts for "operating revenues under present rates" and "total revenues under present rates" was the fuel revenues. The "operating revenues under present rates" include fuel revenues comprised of the actual fuel revenues recorded during the 2008 test period, consistent with the general rate case, inclusive of the base fuel rate, the Rider A rate, and the EMF rate, which resulted in fuel revenues of $93,722,000. The fuel component of "total revenues under present rates" consists of current base fuel tariff rates and Rider A applied to an annualized and normalized level of sales based on actual North Carolina retail customers as of March 31, 2010; this amount is $112,790,000. Both the differences between the fuel revenue components ($112,790,000 minus $93,722,000) and the two revenue amounts ($324,940,000 minus $305,872,000) were now $19,068,000. All other components of the two revenue amounts include the same level of non-fuel base revenues, other customer revenues, and other operating revenues used as revenue credits in the cost of service.

With respect to rate of return and capital structure, on August 27, 2010, DNCP filed supplemental testimony reflecting actual March 31, 2010 cost rates and capitalization percentages in place of the June 30, 2010 projections which had been included in its initial application. The Company affirmed that its overall cost of capital as of March 31, 2010 was 8.981%, based upon a capital structure of 45.143% long-term debt with an embedded cost of 5.640%, 1.769% preferred stock with an embedded cost of 6.605%, and 53.089% common equity with a proposed rate of return on common equity of 11.90%.

The stipulated amounts related to rate of return and capital structure differ from the Company's updated proposal for its cost rates and capital structure. The Stipulation provides that the stipulated revenues are intended to provide DNCP, through sound management, the opportunity to earn an overall rate of return of 8.22% on a North Carolina retail jurisdictional rate base of $591,679,000 (including $72,727,000 of CWIP for VCHEC), with such return being based upon a capital structure composed of 49% long-term debt with an embedded cost of debt of 5.64%, and 51% common equity with a stipulated rate of return on common equity of 10.7%. As declared in the Stipulation, DNCP did not agree that the foregoing return on common equity and capital structure represented its anticipated or actual cost of equity or capital structure, but it accepted the resulting revenue requirement for the purpose of a global settlement of disputed issues in these proceedings.

The Commission has carefully reviewed the Stipulation, the revised Page 4 of the Stipulation, the revised Stipulation Exhibits, the supplemental testimony filed by DNCP in compliance with the Commission's October 8, 2010 Order, and the entire record in this proceeding. The Commission finds and concludes that the foregoing provisions of the Stipulation, as revised, including the stipulated annual increase of $7,682,000 in the level of base rates and charges to be paid by DNCP's North Carolina retail customers, which results in an overall rate of return of 8.22% on jurisdictional rate base and a return on common equity of 10.70% using a capital structure composed of 51% common equity and 49% long-term debt with an embedded cost of debt of 5.64%, are just and reasonable to all parties in consideration of all of the evidence presented in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 17 THROUGH 23

The evidence supporting these findings of fact is contained in the verified general rate case and fuel charge adjustment proceeding applications, the Company's testimony and exhibits, the Stipulation, as revised, the Supplemental Stipulation, the Company's supplemental testimony providing the comprehensive explanation of the Stipulation requested by the Commission in its October 8, 2010 Order, and the entire record in this proceeding.

Pursuant to its most recent fuel rate proceeding, DNCP currently recovers through its fuel rates the changes in the actual fuel costs provided by the NUGs that provide such information and 70% of the changes in the net purchases from PJM, and other wholesale suppliers. All of the capacity and energy payments made by DNCP to NUGs that do not provide actual fuel costs previously have been included in the non-fuel portion of the base rates and were not subject to being changed in fuel charge adjustment proceedings. DNCP proposed in its application to move the following to the fuel component of base rates: all noncapacity purchased power costs for NUGs that are subject to economic dispatch, all net purchases from PJM and other wholesale market suppliers, and all delivered renewable purchased power costs.

Section 3(D) of the Stipulation provides that the pro forma net market purchases of energy from PJM and other wholesale suppliers are the total market energy purchases for the 12 months ended March 31, 2010, priced at the average for that same 12-month period. In its original application, the Company proposed to include 100% of the noncapacity costs for all purchased power subject to economic dispatch (net energy costs) for PJM purchases and nonutility generation purchases in the fuel charge adjustment proceeding. The Company had projected the amount of fuel costs to be recovered in base fuel rates using the average of the volumes and prices for the 12months ended June 30, 2010. In the Stipulation, for the non-fuel base rates, the noncapacity costs for purchased power were based upon the volumes and prices for the 12 months ended March 31, 2010. In the Supplemental Stipulation, for the base fuel rates, the noncapacity costs for purchased power were based upon the volumes and prices for the 12 months ended June 30, 2010.

With respect to how energy purchases from PJM and other wholesale supplies will be treated if the Stipulation is adopted by the Commission, Section 3(D)(1) provides that 85% of the reasonable and prudent energy costs incurred during the fuel charge adjustment proceeding test period are to be recovered through DNCP's fuel factor, and 15% of the energy costs incurred during the updated test year ended March 31, 2010, are included in non-fuel base rates. The Stipulation further provides that the 85% marketer percentage would not be subject to change until the sooner of DNCP's next general rate case or the fuel charge adjustment proceeding held in 2014 (with rates effective January 1, 2015).

In the Company's supplemental testimony providing the comprehensive explanation of the Stipulation requested by the Commission, the Company witnesses elaborated that, in past fuel charge adjustment proceedings, there have been issues as to how much of the energy costs of PJM and other wholesale suppliers could be recovered through fuel rates. In the past two fuel charge adjustment proceedings, the so-called "marketer percentage" has been set at 70%, which meant that 30% of the energy costs of PJM and other wholesale suppliers were considered to be recovered in non-fuel base rates and the other 70% were recoverable in fuel rates. The 70% marketer percentage was to be reset in the 2010 fuel charge adjustment proceeding. Based on changes to G.S..62-133.2 enacted as part of S.L. 2007-397 (Senate Bill 3), the Company proposed in its February 15, 2010 Application to recover 100% of its noncapacity purchased energy costs that were subject to economic dispatch through its fuel rates, adjusted annually in subsequent fuel charge adjustment proceedings. The Stipulation proposes a marketer percentage of 85%, which means 15% of those energy costs would be recovered in non-fuel base rates and the other 85% would be recovered in base fuel rates and adjusted annually through the Company's Rider A. If the Stipulation is approved, this 85% marketer percentage would not be subject to change until the sooner of DNCP's next general rate case or the fuel charge adjustment proceeding to be held in 2014 (with rates effective January 1, 2015).

In response to a question from the Commission during the hearing on October 14, 2010, as to how the 85% was derived, Company witness Morgan testified that DNCP had submitted some data to the parties through discovery that showed what the Company considered to be the most reliable data as it pertained to the sellers' actual cost of fuel in PJM in the last two years, which ranged between 91% and 95%. He further testified that using the method traditionally used by the Public Staff produced numbers in the 78% to 80% range and that the 85% represented a compromise of those two positions.

With respect to DNCP's purchases from dispatchable NUGs that provide actual fuel data, Section 3(D)(2)(a) of the Stipulation provides that the actual fuel costs provided by these NUGs would continue to be recovered through DNCP's fuel factor (the base fuel rate and annual fuel charge adjustment). This currently includes Birchwood, ROVA I, and ROVA II. The difference between this amount and the total energy payments made by DNCP to these three NUGs as of the 12 months ended March 31, 2010, are considered to be recovered in non-fuel base rates in this general rate proceeding, as are the capacity payments made by DNCP for the 12 months ended March 31, 2010. If DNCP enters into contracts with new dispatchable NUGs for which actual fuel costs are provided, the Stipulation provides that this treatment would also apply. Recovery of actual fuel costs reported by NUG operators through the fuel charge adjustment is current practice and will remain the method of recovery for the three NUGs that currently report their fuel expenses, plus any new dispatchable NUG contracts.

For purchases from dispatchable NUGs that do not provide actual fuel cost data, Section 3(D)(2)(b) of the Stipulation provides that 85% of the reasonable and prudent energy costs incurred during the fuel charge adjustment proceeding test period will be recovered through DNCP's fuel factor. For purposes of the general rate case, 15% of the cost of energy purchases from these NUGs during the updated test year ended March 31, 2010, is considered to be recovered in non-fuel base rates. This includes the following: Doswell Complex, Hopewell Cogeneration Facility, Cogentrix Rocky Mount, Cogentrix Richmond 1, and Cogentrix Richmond 2. The

Stipulation further provides that the 85% marketer percentage will not be subject to change until the sooner of DNCP's next general rate case or the fuel charge adjustment proceeding to be held in 2014 (with rates effective January 1, 2015). It also provides that, if any of the foregoing five NUGs ultimately provide actual fuel cost data, then such actual fuel cost data will be used in lieu of the 85% of the energy payment mechanism.

In the Company's supplemental testimony, the Company witnesses elaborated that, although some dispatchable NUGs provide actual fuel data, some do not. In past fuel charge adjustment proceedings, energy purchases from the NUGs that did not provide actual fuel data have been considered to be recovered through base non-fuel rates. Based on changes to G.S. 62-133.2 in Senate Bill 3, the Company proposed in its February 15, 2010 Application to recover 100% of its noncapacity energy changes from NUGs that were subject to economic dispatch through its fuel rates, as adjusted annually. The Stipulation proposes a marketer percentage of 85% for the net market energy purchased from NUGs. This means that 15% of those energy costs are to be considered recovered in non-fuel base rates and the other 85% will be recovered in base fuel rates and Rider A, as adjusted annually. If the Stipulation is approved, this 85% marketer percentage would not be subject to change until the sooner of DNCP's next general rate case or the fuel charge adjustment proceeding to be held in 2014 (with rates effective January 1, 2015).

For purchases from NUGs other than the previously discussed dispatchable NUGs, Section 3(D)(2)(c) of the Stipulation provides that payments to other NUGs from which DNCP made purchases during the 12 months ended March 31, 2010, have been included in DNCP's non-fuel base rates at the expense level incurred during that 12-month period. No fuel costs relating to these NUGs will be included in fuel charge adjustment proceedings prior to DNCP's next general rate case, except that new renewable generating facilities that have registered pursuant to Commission Rule R8-66 and were not operational as of March 31, 2010, can be recovered in accordance with G.S. 62-133.2(a3). This subsection provides that the costs described in G.S. 62-133.2(a1)(6) shall be recoverable from each class of customers as a separate component of the rider.

In the Company's supplemental testimony, DNCP's witnesses elaborated that some NUGs under contract with DNCP are not subject to economic dispatch or do not provide separate fuel cost data. Therefore, under the Stipulation, these costs are to be considered recovered in non-fuel base rates. As to renewable NUGs, the Stipulation maintains the standard established by the amendments in Senate Bill 3 to G.S. 62-133.2(a1)(6), which permits utilities to recover through fuel rates the energy and capacity payments to renewable generation facilities that are not recovered through a REPS Rider pursuant to G.S. 62-133.8(h). G.S. 62-133.2(a3) makes subsection (a1)(6) applicable to DNCP. The Stipulation further provides that if DNCP intends to utilize this provision in future fuel charge adjustment proceedings, it will have to comply with the cost allocation and other limitations contained in G.S. 62-133.2(a3).

With respect to the position of the Stipulating Parties as to the methodology used by DNCP to develop its pro forma adjustments, Section 3(E) of the Stipulation provides that the Stipulating Parties agree that, as included in the calculation of the settled-upon revenue requirement, as well as in the base fuel factor and the EMF, the pro forma adjustments used in the development of the revenue requirement, including the level of PJM purchased power expenses, are appropriate and reasonable for purposes of this proceeding. However, the parties also agreed that neither the methodology utilized to calculate the levels of expense included in Docket No. E-22, Subs 459 and 461, nor the methods used by DNCP to calculate the per books PJM purchased power expense during the test years and the update period utilized in Docket No. E-22, Subs 459 and 461, shall be considered precedential. Furthermore, DNCP agreed to cooperate with the Public Staff in its continuing evaluation of the appropriate treatment of PJM purchased power expenses in future general rate cases and annual fuel charge adjustment proceedings.

Having carefully reviewed the Stipulation, as revised, the supplemental testimony filed by DNCP in compliance with the Commission's October 8, 2010 Order, and the entire record, the Commission finds and concludes that the foregoing purchased power provisions of the Stipulation are just and reasonable and should be approved in their entirety. However, the limitation on any change in the 85% marketer percentage is accepted subject to the condition that the present Commission cannot bind future Commissions with respect to future ratemaking decisions in the relevant DNCP fuel charge adjustment proceedings.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 24 AND 25

The evidence supporting these findings of fact is contained in the verified general rate case application, DNCP's NCUC Form E-1, the Company's testimony and exhibits, the Stipulation, as revised, the Company's supplemental testimony providing the comprehensive explanation of the Stipulation requested by the Commission in its October 8, 2010 Order, and the entire record in this proceeding.

The Stipulation provides that, when DNCP conducts a depreciation study, it will file such study with the Commission before changing its depreciation rates, which the Commission concludes is just and reasonable. In the Company's supplemental testimony provided to respond to one of the Commission's questions in its October 8, 2010 Order, the Company stated that the annualized amount of its depreciation and amortization expense, as updated, included as an operating revenue deduction under the provisions of the Stipulation is $36,026,000, the details of which are shown on Company Joint Testimony Exhibit 2 filed on October 12, 2010. The actual amount of depreciation and the annualization adjustment was provided in NCUC Form E-1, Item 10 (Supplemental), Page 137, Adjustment No. 28, which compared actual depreciation expense of $30,906,000 per the 2008 test period with annualized depreciation expense based on plant in service at March 31, 2010. Such information was provided on both a total-company and a North Carolina jurisdictional basis, as requested. The Commission finds and concludes that the foregoing is reasonable and appropriate to use in this proceeding and should be approved.

With respect to the adjustment to DNCP's Voluntary Separation Program, the Stipulation provides that the incorporation of costs associated with the Voluntary Separation Program does not create a deferred asset, and the treatment of those costs in this case was for settlement purposes only. In its supplemental testimony in response to the Commission's October 8, 2010 Order, the Company witnesses elaborated that its Voluntary Separation Program was established to reduce costs by reducing its workforce, but that it required both severance payments to employees taking advantage of the program as well as additional benefits cost. This provision of the Stipulation makes clear that no deferred asset has been created for the purposes of this case, and that this treatment is not precedential. The Commission finds and concludes that this aspect of the Stipulation is just and reasonable for purposes of this proceeding and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 26 AND 27

The evidence supporting these findings of fact is contained in the Company's testimony and exhibits, the Stipulation, as revised, the Company's supplemental testimony providing the comprehensive explanation of the Stipulation requested by the Commission in its October 8, 2010 Order, and the entire record in this proceeding.

Section 3(H) of the Stipulation provides that all labor costs and corporate overheads associated with implementing and maintaining the REPS program will continue to be recovered through base rates until the Company's next general rate case and that DNCP intends to recover incremental REPS costs through a separate rider in accordance with G.S. 62-133.8(h). In its supplemental testimony in response to the Commission's October 8, 2010 Order, the Company witnesses elaborated that this provision makes clear that the Stipulation does not preclude DNCP from utilizing the provisions of Senate Bill 3 that permit a utility to file an application for a REPS Rider to recover costs for participating in North Carolina's REPS program. This provision also makes clear that any such REPS Rider will not include labor costs (i.e., employee program administration costs) or corporate overhead, which are considered to be recovered through non-fuel base rates.

In addition, the Stipulation provides that DNCP does not have any costs at this time to be recovered under G.S. 62-133.2(a3), which provides that, for the costs described in G.S. 62-133.2(a1)(6), the specific component for each class of customers shall be determined by allocating these costs among customer classes based on the electric public utility's North Carolina peak demand for the prior year, as determined by the Commission, until the Commission determines how these costs shall be allocated in a general rate case commenced on or after January 1, 2008. The Stipulation provides that these costs will be allocated as provided for in the statute unless changed in DNCP's next general rate case proceeding.

The Commission finds and concludes that both of the sections of the Stipulation dealing with the REPS program are just and reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 28

The evidence supporting this finding of fact is contained in the Company's fuel charge adjustment proceeding application and the testimony and exhibits filed to support that application, the Stipulation, as revised, the Supplemental Stipulation, the Company's supplemental testimony providing the comprehensive explanation of the Stipulation requested by the Commission in its October 8, 2010 Order, and the entire record in this proceeding.

On August 10, 2010, DNCP filed its annual application for a change in its fuel rates. DNCP stated that it had over-recovered its test year fuel costs by $14,485,503 and requested a negative EMF to return those dollars to its ratepayers. In summary, the application stated that the proposed fuel cost level results in a decrease in fuel revenue of $28,094,956. In its application, DNCP requested approval of the following: a base fuel factor for residential, small general service, outdoor lighting and traffic of 2.886 ¢/kWh; a base fuel factor for large general service, 6VP and Schedule NS of 2.589 ¢/kWh; and a Rider B EMF decrement of 0.354 ¢/kWh for all classes. Based upon the pro forma number of kWh for the 12 months ended March 31, 2010, DNCP's fuel case filings requested an annual increase in base fuel revenues of $2,386,000 and a decrease in EMF revenues of $30,000,000.

The Stipulation and the Supplemental Stipulation provide that DNCP will reduce its current period fuel factor recovery (base fuel plus Rider A) by $4,623,477. The amount of the decrease results from applying the difference between the fuel factor (base plus Rider A) approved in Docket No. E-22, Sub 456, and the voltage-differentiated base fuel factors to be established in this general rate case proceeding to the adjusted kWh sales for the general rate case test period. The Commission finds and concludes that this aspect of the Stipulation, as revised, and Supplemental Stipulation is just and reasonable and should be approved.

In the Company's supplemental testimony providing the comprehensive explanation of the Stipulation requested by the Commission, DNCP's witnesses elaborated that DNCP's base fuel rate is being reset in this proceeding. In its February 15, 2010 general rate case application, the Company projected (as of June 30, 2010) that the base component of fuel would increase by $16.7 million. This projection included moving from non-fuel base rates to base fuel rates 100% of noncapacity purchased power from PJM and other wholesale suppliers, dispatchable NUGs, and energy and capacity from renewable facilities. Under the Stipulation and Supplemental Stipulation, the base fuel rate was set using actual costs for the 12 months ending June 30, 2010, for purchases from PJM (and other wholesale suppliers) and the NUGs and then applying the 85% marketer percentage to the costs for PJM purchases and for the five dispatchable NUGs that do not provide actual fuel costs. For the three dispatchable NUGs that provide their fuel costs, the actual fuel costs for the 12 months ending June 30, 2010, also were used. As a result, base fuel rate revenues will be reduced by $4,623,477 (based on general rate case test year kWh sales, as noted above), pursuant to the Stipulation and Supplemental Stipulation. In addition, the Stipulation provides that this fuel rate decrease will be flowed though to all customers on a voltage-differentiated basis. Because the base fuel rate is being reset in this proceeding, Rider A is zero. The Commission finds and concludes that this aspect of the Stipulation and the Supplemental Stipulation is just and reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 29

The Commission has previously discussed its findings of fact and conclusions with respect to the appropriate amount of increase in non-fuel revenues and the fair rates of return that DNCP should be afforded the opportunity to earn. The Commission finds and concludes that the following amounts of operating revenues, operating revenue deductions, and original cost rate base under present base rates, which exclude the base fuel charge adjustments in Docket No. E-22, Sub 461, are appropriate and reasonable for purposes of setting rates in this proceeding: $305,872,000 of electric operating revenues, $261,685,000 of operating revenue deductions, and $591,679,000 of original cost rate base, as provided in Revised Stipulation Exhibit II, Schedule 1 and Stipulation Exhibit II, Schedule 2, respectively. The $305,872,000 of electric operating revenues includes actual fuel revenues recorded during the 2008 test period, consistent with the general rate case, inclusive of the base fuel rate, the Rider A rate, and the EMF rate, which results in base fuel revenues of $93,722,000; and the $261,685,000 of operating revenue deductions includes fuel expenses of $90,616,000 as a component of operation and maintenance expenses.

The following schedules summarize the gross revenues and the rate of return that the Company should have a reasonable opportunity to achieve based upon the determinations made herein. These schedules, illustrating the Company's gross revenue requirement (based upon the specific amounts of revenues, operating revenue deductions, and rate base agreed to by the Stipulating Parties in Docket No. E-22, Sub 459), incorporate the findings and conclusions made by the Commission in this Order. As reflected in Schedule I, and as impacted by the other findings in this Order, DNCP is authorized to increase its annual level of base non-fuel revenues by $7,682,000 based upon the adjusted test year level of operations:

SCHEDULE I
VIRGINIA ELECTRIC & POWER COMPANY
d/b/a DOMINION NORTH CAROLINA
North Carolina Retail Operations
Docket No. E-22, Sub 459
STATEMENT OF OPERATING INCOME
Twelve Months Ended December 31, 2008
Updated through March 31, 2010
(000s Omitted)

Item	Present Rates	Approved Increase	Approved Rates
Electric operating revenues	$ 305,872	$ 7,682	$ 313,554
Operating revenue deductions:			
Uncollectibles expense	1,389	32	1,421
Operations and maintenance expenses	184,199	9	184,208
Depreciation and amortization	36,026	-	36,026
Gain on disposition of property	(143)	-	(143)
Taxes other than income taxes	18,653	246	18,899
Income taxes	21,519	2,942	24,461
Interest on customer deposits	161	-	161
Interest on tax deficiencies	(119)	-	(119)
Total operating revenue deductions	$ 261,685	$ 3,229	$ 264,914
Net Operating Income	$ 44,187	$ 4,453	$ 48,640

SCHEDULE II
VIRGINIA ELECTRIC & POWER COMPANY
d/b/a DOMINION NORTH CAROLINA
North Carolina Retail Operations
Docket No. E-22, Sub 459
STATEMENT OF RATE BASE AND RATE OF RETURN
Twelve Months Ended December 31, 2008
Updated through March 31, 2010
(000s Omitted)

Item	Amount
Electric plant in service, including nuclear fuel	$ 1,173,089
Accumulated depreciation and amortization	(522,264)
Construction work in progress (CWIP)	72,727
Net electric plant in service and CWIP	723,552
Materials and supplies	29,562
Cash working capital	14,157
Other working capital	(10,147)
Customer deposits	(3,872)
Accumulated deferred income taxes	(161,573)
Total Original Cost Rate Base	$ 591,679
Overall Rates of Return:	
Present rates	7.47%
Approved rates	8.22%

SCHEDULE III
VIRGINIA ELECTRIC & POWER COMPANY
d/b/a DOMINION NORTH CAROLINA
North Carolina Retail Operations
Docket No. E-22, Sub 459
STATEMENT OF RATE BASE AND RATE OF RETURN
Twelve Months Ended December 31, 2008
Updated through March 31, 2010
(000s Omitted)

Present Rates – Original Cost Rate Base

Item	Capitalization Ratio	Original Cost Rate Base	Embedded Cost or ROE	Net Operating Income
Long-term debt	49.00%	$ 289,923	5.64%	$ 16,352
Common equity	51.00%	301,756	9.22%	27,835
Total	100.00%	$ 591,679		$ 44,187

Approved Rates – Original Cost Rate Base

Item	Capitalization Ratio	Original Cost Rate Base	Embedded Cost or ROE	Net Operating Income
Long-term debt	49.00%	$ 289,923	5.64%	$ 16,352
Common equity	51.00%	301,756	10.70%	32,288
Total	100.00%	$ 591,679		$ 48,640

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 30

The evidence supporting this finding of fact is contained in the verified general rate case and supplemental applications, the testimony and exhibits of the Company's witnesses, the testimony of Public Staff witness Ellis, the Stipulation, as revised, and the entire record in this proceeding.

On July 30, 2010, DNCP filed a supplemental application, testimony and exhibits pursuant to G.S. 62-110.6 providing additional testimony and information with respect to the need, estimated construction costs, and estimated construction schedule for certain out-of-state generating facilities. In support of the VCHEC, the Company filed the Supplemental Direct Testimony and Exhibits of Mark D. Mitchell, Director – Fossil and Hydro Construction for the Company; M. Masood Ahmad, Director of Integrated Resource Planning for the Company; Glenn A. Kelly; Alexander N. Bailey; Gregory A. Workman, Director – Fuels for the Company; and Sidney J. Bragg, Director of Fossil and Hydro Operations for the Company.

The Stipulation provides that, with respect to VCHEC, which is an electric generating facility in Virginia that is intended to serve retail customers in North Carolina, DNCP has made a sufficient showing to establish the need for it, and that the estimate of the construction costs and construction schedule as set forth in the supplemental application of DNCP, filed July 30, 2010 in this docket, should be approved. The Stipulation further provides that it is appropriate to include $72,727,000 related to VCHEC as CWIP in DNCP's rate base.

In the Company's supplemental testimony providing the comprehensive explanation of the Stipulation requested by the Commission, DNCP's witnesses elaborated that, pursuant to G.S. 62-133(b)(1), CWIP for baseload generation facilities may be included for recovery in base rates. The Company sought recovery for CWIP related to VCHEC and provided evidence, as required by G.S. 62-110.6, as to the need, estimated construction costs, and construction schedule for VCHEC. The Public Staff investigated the need, costs, and schedule for VCHEC and filed testimony on September 29, 2010, supporting the facility.

In this regard, the Commission notes that Public Staff witness Ellis testified that the results of DNCP's STRATEGIST model showed that the addition of the VCHEC facility over the 15-year planning horizon had a net present value savings of $186.9 million over the next best generation expansion plan. He further testified that this provides adequate support for a finding that VCHEC is the least cost resource for the Company's future generation needs and that the assumptions used in DNCP's evaluation of the need for VCHEC are reasonable. Finally, he testified that the facility and construction costs are commensurate with expected and benchmark values for this type of facility and that, based upon the Public Staff's site visit, the construction schedule submitted by DNCP in this proceeding was reasonable.

The Commission finds and concludes that this aspect of the Stipulation is just and reasonable and that construction of the VCHEC facility is needed to assure the provision of adequate public utility service in North Carolina. In addition, the Commission finds and concludes that the construction cost estimate and the construction schedule submitted by DNCP in this proceeding are reasonable and should be approved. As required by G.S. 62-110.6(d), which makes G.S. 62-110.1(f) applicable, and Commission Rule R8-61(f), DNCP should submit a progress report and any revision in the construction cost estimate for VCHEC during each year of construction. Such reports should be due annually on the date of the issuance of this Order for the 12 months ending the immediately preceding September 30th until construction is completed, at which time DNCP will notify the Commission by a filing in this docket.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 31

The evidence supporting this finding of fact is contained in the verified general rate case and supplemental applications, the testimony and exhibits of the Company's witnesses, the Stipulation, as revised, and the entire record in this proceeding.

The Stipulation provides as follows: DNCP agrees to withdraw its supplemental application with respect to Bear Garden and the Ladysmith Units. It agrees that no costs related to the Bear Garden generating station are to be included in the revenue requirement, and it agrees that recovery of any such costs shall be reserved for a future proceeding.

In the Company's supplemental testimony providing the comprehensive explanation of the Stipulation requested by the Commission, DNCP's witnesses elaborated that in its initial application and in its supplemental application and testimony filed under G.S. 62-110.6, the Company requested that its investment in Bear Garden be included in rate base and that operation and maintenance expenses be included in rates even though the facility was not yet complete. The Company asserted that, because the facility would be operational relatively soon (approximately May 2011) after new rates were to go into effect (January 1, 2011), Bear Garden should be included in its cost of service and recovered through its new rates. DNCP also proposed that a decrement rider be applied to customers' bills for the months Bear Garden was not yet operational. The Stipulating Parties agreed that DNCP would withdraw its request in this case and that it is not prohibited from seeking recovery of costs for Bear Garden in future proceedings.

With respect to the Ladysmith Units, the Stipulation provides that the construction of these units has been completed, and their inclusion in rates in this proceeding is not opposed. The Commission finds and concludes that this aspect of the Stipulation is just and reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 32 THROUGH 35

The evidence supporting these findings of fact is contained in the verified general rate case application, the testimony and exhibits of the Company's witnesses, the Stipulation, as revised, and the entire record in this proceeding.

DNCP based its general rate case filing on the Summer-Winter Peak and Average (SWPA) methodology for the allocation of revenues, operating revenue deductions, and rate base among jurisdictions and among customer classes. DNCP and the Public Staff stipulated that, as adjusted on a jurisdictional basis for Nucor's interruptible load, this methodology is appropriate for use in this proceeding. The Stipulation further states that CIGFUR and CUCA did not agree that the SWPA methodology is appropriate for allocations among customer classes either generally or under the particular circumstances of this case. For purposes of a global settlement, however, CIGFUR and CUCA accepted the use of this methodology in this case. With respect to Nucor, the Stipulation states that Nucor did not agree that the SWPA methodology is appropriate for allocating DNCP's fixed production costs to the North Carolina jurisdiction or among retail classes. In addition, it stated that Nucor did not agree that the treatment of Nucor's interruptible load in DNCP's SWPA cost studies was appropriate. Nonetheless, for global settlement purposes only, Nucor agreed with the base revenue increase assigned to Schedule NS under the revenue spread reflected in the Stipulation. The Commission concludes that this provision of the Stipulation is just and reasonable and should be approved.

With respect to rate design, Section 9(A) of the Stipulation provides that, in this proceeding, non-fuel base rates for each class should be designed to produce increases for each class in accordance with the numbers in the column labeled "Non-Fuel Revenue Increases" in the table found in Paragraph 3(A) of the Stipulation. (The sum of the Non-Fuel Revenue Increases from electricity sales to all classes, less the $200,000 decrease in Miscellaneous Revenues, equals $7,682,000.) In addition, the Stipulation provided that non-fuel base rates within each rate schedule were to be increased using an "across-the-board" approach, meaning that all rates within a given rate schedule would be increased using the same percentage increase associated with the non-fuel percentage increase for each respective class. The Company provided the following as an example: if the Residential Class's approved non-fuel base revenue increase produced a percentage increase of 3.5% compared to present non-fuel base revenues, then all non-fuel base prices within Residential Rate Schedule 1 will be increased by 3.5%. The Stipulating Parties further agreed that rates should be designed in accordance with Appendix A attached to the Stipulation, which shows (1) present base revenues (including non-fuel and fuel, but not the EMF); (2) the non-fuel base revenue increase; and (3) the effect of using voltage differentiation in the base fuel rate. For the base fuel decrease, the Stipulation provided that, except for being adjusted for voltage differentiation, the base fuel decrease was to flow back to all customer classes uniformly. The Commission concludes that these aspects of the Stipulation are just and reasonable, and rates should be designed as specified therein.

With respect to the Terms of Conditions, Section 9(B) of the Stipulation provides that DNCP's Terms and Conditions should be revised as set forth in Appendix B to the Stipulation. In the Company's supplemental testimony providing the comprehensive explanation of the Stipulation requested by the Commission, DNCP's witnesses elaborated that the Company had proposed several changes to its terms and conditions in its initial application and that the agreed-upon changes were detailed in Appendix B to the Stipulation. The Commission concludes that this aspect of the Stipulation is just and reasonable and that DNCP's Terms and Conditions should be revised as detailed in Appendix B to the Stipulation.

With respect to the quality of DNCP's electric service, Section 10 of the Stipulation provides that all of the Stipulating Parties agreed that the overall quality of electric service provided by DNCP is adequate. The majority of the testimony, letters, and emails sent regarding this proceeding related to the timing and magnitude of the requested rate increase and were not related to quality of service concerns. The Commission concludes that this aspect of the Stipulation is just and reasonable and that the overall quality of DNCP's electric service is adequate.

With respect to the joint notice of contract extension and motion for approval of the Amended Agreement filed by Nucor and DNCP on September 28, 2010, the Public Staff and DNCP filed on November 16, 2010, a summary of the more significant changes made in the Amended Agreement and supplemental language providing that the Amended Agreement, once revised to be consistent with the rate changes approved in the proceeding, should be allowed to become effective. On November 22, 2010, Nucor filed a statement of support for Proposed Order submitted on November 4, 2010, as supplemented. Based upon the foregoing and the entire record in this proceeding, the Commission concludes that the Amended Agreement, after the stated rates therein have been revised to be consistent with the rate changes approved herein, should be allowed to become effective. At the time that DNCP files its rate schedules designed to produce revenues as approved herein it also shall file the revised Amended Agreement and Schedule NS for Commission approval.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 36 THROUGH 53

The evidence supporting these findings of fact is contained in the verified general rate case and fuel charge adjustment proceeding applications, the Company's testimony and exhibits, the Stipulation, as revised, the Supplemental Stipulation, the Company's supplemental testimony providing the comprehensive explanation of the Stipulation requested by the Commission in its October 8, 2010 Order, and the entire record in this proceeding.

The stipulated base fuel rates were calculated on a voltage-differentiated basis and the Stipulation provides that Rider A increments and decrements to the base fuel rates in subsequent fuel charge adjustment proceedings will be calculated on a voltage-differentiated basis unless changed in DNCP's next general rate case. For purposes of the EMF calculation, monthly fuel costs will begin to be measured in a voltage-differentiated manner as of January 1, 2011. The present Commission cannot bind future Commissioners making ratemaking decisions in future DNCP fuel charge adjustment proceedings, but the Commission accepts this part of the Stipulation subject to this condition.

With respect to fuel procurement, Commission Rule R8-52(b) requires each electric utility to file a Fuel Procurement Practices Report at least once every ten years and each time the utility's fuel procurement practices change. The Company's current fuel procurement practices were filed with the Commission in Docket No. E-100, Sub 47A, on July 10, 2008. The Supplemental

Stipulation provides that DNCP's fuel procurement and purchasing practices during the fuel case test period were reasonable and prudent, and no party offered testimony to the contrary. The Commission concludes that the Company's fuel procurement and purchasing practices during the fuel case test period were reasonable and prudent.

The Supplemental Stipulation provides the per book MWh of generation on a total system basis and the MWh of generation by the various types of generation, the adjusted MWh sales on a total system basis, the adjusted MWh of generation on a total system basis and the adjusted MWh of generation by the various types of generation, the appropriate fuel prices to be used, and the total adjusted fuel expense on a total system basis. The Supplemental Stipulation also provides that the fuel-related numbers are based on the test year for the fuel charge adjustment proceeding, which is the 12 months ended June 30, 2010. However, for the purpose of reporting these amounts in the context of the general rate case, the revenues and expenses related to fuel were recalculated for the Supplemental Stipulation based upon the kWh sales for the 12 months ended December 31, 2008, updated for customer growth and changes in usage through March 31, 2010, as used in the general rate case.

In the Company's testimony providing the comprehensive explanation of the Stipulation requested by the Commission in its October 8, 2010 Order, DNCP stated that the actual system nuclear capacity factor for the fuel charge adjustment proceeding test year was 93.6%, the NERC average for 2005-2009 for pressurized water reactors was 91.5%, and the projected system nuclear capacity factor for 2011 is 94.3%. The Commission concludes that the nuclear capacity factor appropriate for use in this proceeding is 94.3%, which is the estimated nuclear capacity factor for the 12 months beginning January 1, 2011.

Based upon the foregoing, the Commission concludes that the proper aggregate base fuel factor for this proceeding is 2.511¢/kWh, excluding gross receipts tax, or 2.595¢/kWh, including gross receipts tax. The Supplemental Stipulation provides that the voltage-differentiated fuel factors, including gross receipts tax, by customer class and the base fuel factors to be established in Docket No. E-22, Sub 459, are as follows:

Residential	2.623 ¢/kWh
SGS &PA	2.622 ¢/kWh
LGS	2.602 ¢/kWh
NS	2.522 ¢/kWh
6VP	2.574 ¢/kWh
Outdoor Lighting	2.623 ¢/kWh
Traffic	2.622 ¢/kWh

The Commission finds and concludes that the foregoing voltage-differentiated fuel factors (including gross receipts tax) by class are just and reasonable and that such fuel factors should be established as the base fuel factors in Docket No. E-22, Sub 459.

The table below shows the following by customer class: adjusted North Carolina retail kWh sales, for the 12 months ended December 31, 2008, updated for customer growth and changes in usage through March 31, 2010; the present fuel rate (including the base fuel factor, Rider A, and gross receipts tax (GRT)); the new base fuel factor on a voltage-differentiated basis (including GRT); and the resulting change in revenues:

Customer Class	kWh Adjusted Through March 31, 2010	Present Rate w/ GRT	Voltage-Differentiated Rate w/ GRT	Revenue Change
Residential	1,609,061,810	2.707 ¢/kWh	2.623 ¢/kWh	$ (1,351,612)
SGS and PA	824,858,028	2.707 ¢/kWh	2.622 ¢/kWh	(701,129)
LGS	495,113,015	2.707 ¢/kWh	2.602 ¢/kWh	(519,869)
NS	802,435,828	2.707 ¢/kWh	2.522 ¢/kWh	(1,484,506)
6VP	409,880,846	2.707 ¢/kWh	2.574 ¢/kWh	(545,142)
Outdoor/Street Lights	24,666,055	2.707 ¢/kWh	2.623 ¢/kWh	(20,719)
Traffic Lights	588,097	2.707 ¢/kWh	2.622 ¢/kWh	(500)
Total NC	4,166,603,679			$ (4,623,477)

With respect to the study DNCP is required to conduct to demonstrate that it has complied with Ordering Paragraph 1(e) of the Order Approving Transfer with Conditions issued April 19, 2005, in Docket No. E-22 Sub 418, the Supplemental Stipulation provides that the approach approved in Docket No. E-22, Sub 456, should be used for the study to be conducted by DNCP for the 2011 fuel charge adjustment proceeding. The Commission concludes that this aspect of the Supplemental Stipulation is reasonable and appropriate.

With respect to DNCP's overcollection during the fuel test year, the Supplemental Stipulation provides that the appropriate North Carolina retail jurisdictional fuel expense overcollection is $11,811,781 (including interest at 10% per annum) and that the adjusted North Carolina retail jurisdictional sales for the fuel case test year are 4,224,805 MWh. The Commission finds and concludes that these aspects of the Supplemental Stipulation are just and reasonable and that the appropriate EMF for this proceeding is a decrement of 0.280¢/kWh, excluding gross receipts tax, or 0.289¢/kWh, including gross receipts tax. This EMF is to be refunded to North Carolina retail customers on a uniform basis.

The Commission further concludes that the final net aggregate fuel factor is 2.231¢/kWh, excluding gross receipts tax, or 2.306¢/kWh, including gross receipts tax, and, when the fuel factor (not including the EMF) is differentiated by class based on the voltage at which service is taken, the resulting total net voltage-differentiated fuel rates, including gross receipts tax, to be billed to DNCP's North Carolina retail customers during the 2011 fuel charge adjustment billing period are as follows:

Residential	2.334 ¢/kWh
SGS & PA	2.333 ¢/kWh
LGS	2.313 ¢/kWh
NS	2.233 ¢/kWh
6VP	2.285 ¢/kWh
Outdoor Lighting	2.334 ¢/kWh
Traffic	2.333 ¢/kWh

The Commission finds and concludes that the foregoing final net voltage-differentiated fuel rates are just and reasonable and should be approved.

The Supplemental Stipulation also provides that the EMF decrement on a cents-per-kWh basis was calculated using the kWh for the 12 months ending June 30, 2010, but the decrement was applied to the kWh for the 12 months ending December 31, 2008, updated for customer growth and changes in usage through March 31, 2010, for the purpose of showing a comparable revenue requirement effect for the general rate case, which the Commission concludes is reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 54

The evidence supporting this finding of fact is contained in the verified general rate case and fuel charge adjustment proceeding applications, the Company's testimony and exhibits, the Stipulation, as revised, the Supplemental Stipulation, the Company's supplemental testimony providing the comprehensive explanation of the Stipulation requested by the Commission in its October 8, 2010 Order, the Public Staff's October 13, 2010 filing of Stipulation Exhibit III, and the entire record in this proceeding. Stipulation Exhibit III presented, among other things, a restatement of Revised Stipulation Exhibit II, Schedule 1, expanded to include both base non-fuel and base fuel revenues and expenses, annualized at March 31, 2010, and the agreed-upon increases and decreases to each, respectively.

The Commission has previously discussed its findings and conclusions with respect to the appropriate amount of changes to the base non-fuel and base fuel rates, and has determined that the stipulated North Carolina jurisdictional non-fuel revenue increase of $7,682,000 and the stipulated fuel revenue decrease of $4,623,477 are appropriate. When combined with the approved increase in base non-fuel rates, the imposition of the fuel rates in this proceeding results in a total base revenue requirement increase of $3,058,523, calculated on the basis of adjusted test year sales for the year ended March 31, 2010.

The following schedules summarize the gross revenues and the rate of return that the Company should have a reasonable opportunity to earn based on the determinations made in this Order regarding non-fuel and fuel revenues. In the following Schedule A, the $324,940,000 of electric operating revenues includes fuel revenues of $112,790,000 consisting of the current base fuel tariff rates and Rider A applied to an annualized and normalized level of sales based on actual North Carolina retail customers as of March 31, 2010; and the $278,058,000 of operating revenue deductions includes fuel expenses of $104,683,000 as a component of operation and maintenance expenses. As reflected in Schedule A, and as impacted by the other findings in this Order, DNCP is authorized to increase its annual level of base revenues (non-fuel and fuel) by $3,059,000 based upon the adjusted general rate case test year level of operations:

ELECTRIC – RATE INCREASE

SCHEDULE A
VIRGINIA ELECTRIC & POWER COMPANY
d/b/a DOMINION NORTH CAROLINA
North Carolina Retail Operations
Docket No. E-22, Sub 459
STATEMENT OF OPERATING INCOME
(Including Base Fuel Adjustments)
Twelve Months Ended December 31, 2008
Updated through March 31, 2010
(000s Omitted)

Item	Present Rates	Approved Increase	Approved Rates
Electric operating revenues	$ 324,940	$ 3,059	$ 327,999
Operating revenue deductions:			
Uncollectibles expense	1,389	32	1,421
Operations and maintenance expenses	198,266	9	198,275
Depreciation and amortization	36,026	-	36,026
Gain on disposition of property	(143)	-	(143)
Taxes other than income taxes	19,179	97	19,276
Income taxes	23,299	1,163	24,462
Interest on customer deposits	161	-	161
Interest on tax deficiencies	(119)	-	(119)
Total operating revenue deductions	$ 278,058	$ 1,301	$ 279,359
Net Operating Income	$ 46,882	$ 1,758	$ 48,640

SCHEDULE B
VIRGINIA ELECTRIC & POWER COMPANY
d/b/a DOMINION NORTH CAROLINA
North Carolina Retail Operations
Docket No. E-22, Sub 459
STATEMENT OF RATE BASE AND RATE OF RETURN
(Including Base Fuel Adjustments)
Twelve Months Ended December 31, 2008
Updated through March 31, 2010
(000s Omitted)

Item	Amount
Electric plant in service, including nuclear fuel	$ 1,173,089
Accumulated depreciation and amortization	(522,264)
Construction work in progress (CWIP)	72,727
Net electric plant in service and CWIP	723,552
Materials and supplies	29,562
Cash working capital	14,157
Other working capital	(10,147)
Customer deposits	(3,872)
Accumulated deferred income taxes	(161,573)
Total Original Cost Rate Base	$ 591,679
Overall Rates of Return:	
Present rates	7.92%
Approved rates	8.22%

SCHEDULE C
VIRGINIA ELECTRIC & POWER COMPANY
d/b/a DOMINION NORTH CAROLINA
North Carolina Retail Operations
Docket No. E-22, Sub 459
STATEMENT OF RATE BASE AND RATE OF RETURN
(Including Base Fuel Adjustments)
Twelve Months Ended December 31, 2008
Updated through March 31, 2010
(000s Omitted)

Present Rates – Original Cost Rate Base

Item	Capitalization Ratio	Original Cost Rate Base	Embedded Cost or ROE	Net Operating Income
Long-term debt	49.00%	$ 289,923	5.64%	$ 16,352
Common equity	51.00%	301,756	10.12%	30,530
Total	100.00%	$ 591,679		$ 46,882

Approved Rates – Original Cost Rate Base

Item	Capitalization Ratio	Original Cost Rate Base	Embedded Cost or ROE	Net Operating Income
Long-term debt	49.00%	$ 289,923	5.64%	$ 16,352
Common equity	51.00%	301,756	10.70%	32,288
Total	100.00%	$ 591,679		$ 48,640

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 55

The evidence supporting this finding of fact is contained in the verified general rate case and fuel charge adjustment proceeding applications, the Company's testimony and exhibits, the Stipulation, as revised, the Supplemental Stipulation, the Company's supplemental testimony providing the comprehensive explanation of the Stipulation requested by the Commission in its October 8, 2010 Order, and the entire record in this proceeding.

With respect to DNCP's EMF, the Stipulation provides that effective January 1, 2011, DNCP will discontinue collecting the currently approved EMF increment and will implement an EMF decrement to refund its overcollection for the 12 months ended June 30, 2010. Section 5 of the Stipulation stated that the total estimated change to EMF revenues was $27,291,254 (calculated using adjusted kWh sales for the general rate case test year ended March 31, 2010), after being adjusted to (1) change the marketer percentage for PJM net purchases from 70% to 85% and (2) include interest at 10% per year on the fuel test year over-recovery of $10,271,114. Appendix A of the Supplemental Stipulation confirms that the parties ultimately agree as to the accuracy of the $27,291,254 amount. The Stipulation provides that the EMF over-recovery calculated in the fuel charge adjustment proceeding has been and should remain adjusted to change the marketer percentage for PJM net purchases from 70% to 85%.

In the Company's supplemental testimony providing the comprehensive explanation of the Stipulation requested by the Commission, DNCP's witnesses elaborated that Section 5 of the Stipulation provides that the new EMF decrement is based on DNCP's traditional fuel test year ending June 30, 2010. In setting the EMF, the marketer percentage for PJM net purchases and other wholesale purchases is being calculated at 85%, as has been the traditional application of the established marketer percentage in setting the EMF. The refund through the EMF will be provided to all customers on a uniform basis, and will not retroactively apply voltage-differentiated fuel rates. The Commission finds and concludes that this aspect of the Stipulation is just and reasonable and the refund of the current overcollection should be on a uniform basis.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 56 THROUGH 58

The evidence supporting these findings of fact is contained in the verified general rate case and fuel charge adjustment proceeding applications, the Company's testimony and exhibits, the Stipulation, as revised, the Supplemental Stipulation, the Company's supplemental testimony providing the comprehensive explanation of the Stipulation requested by the Commission in its October 8, 2010 Order, and the entire record in this proceeding.

These findings of fact with respect to the appropriate changes in overall revenues and revenues by customer class incorporate the findings and conclusions made by the Commission in this Order. Based upon the provisions of the Stipulation and of the Supplemental Stipulation, the Supplemental Stipulation provides that the non-fuel base rates for each customer class should be designed to produce increases for each class in accordance with Appendix A, attached to the Supplemental Stipulation. The Commission concludes that the appropriate overall increase in non-fuel base revenues for the North Carolina retail jurisdiction is $7,882,000 (excluding the effect of the reduction of $200,000 in the facilities and miscellaneous charges) or 2.53% and the percentage increases in non-fuel revenues for each customer class should be distributed among the customer classes as stipulated in the Supplemental Stipulation Appendix A, at Line 6. The rates resulting from this non-fuel revenue requirement increase will not change until DNCP's next general rate case adjustment.

With respect to the base fuel revenue change, the Supplemental Stipulation provides that the percentage changes in base revenues resulting from the addition of the stipulated decrease in base fuel revenues should be distributed among the customer classes as stipulated in the Supplemental Stipulation Appendix A, at Line 9. The Commission concludes that the distribution among customer classes of the stipulated fuel decrease of $4,623,477 is appropriate and that it reduces the 2.53% non-fuel base increase to an overall 1.00% increase on a North Carolina retail jurisdictional basis. The fuel portion of the revenues is subject to change in each of DNCP's subsequent fuel charge adjustment proceedings.

Finally, with respect to the change in revenues resulting from the decrease in EMF revenues of $27,291,254, the Supplemental Stipulation provides that the percentage change in overall revenues resulting from the non-fuel base increase, the base fuel decrease, and the decrease in EMF revenues should be distributed among the customer classes as stipulated in the Supplemental Stipulation Appendix A, at Line 12. The Commission concludes that the resulting overall decrease, which is a 7.37% decrease on a North Carolina retail jurisdictional basis, is appropriate. This decrease will only be in effect for the next 12 months.

IT IS, THEREFORE, ORDERED as follows:

1. That the Commission hereby approves in their entirety the Stipulation entered and filed on September 28, 2010, as revised, and the Supplemental Stipulation entered and filed on October 11, 2010, among DNCP, the Public Staff, CIGFUR, Nucor, and CUCA, subject to the provisions of Ordering Paragraph No. 6.

2. That DNCP shall be allowed to increase its rates and charges effective for service rendered as of January 1, 2011, so as to produce an increase in annual base non-fuel revenue for its North Carolina retail operations of $7,682,000 based upon the adjusted test year level of operations, as set forth in this Order.

3. That the non-fuel rate design agreed upon or accepted and provided in Appendix A to the Stipulation shall be, and hereby is, approved.

4. That DNCP shall implement the base fuel rates approved in this Order to reduce its annual fuel revenues by $4,623,477 (calculated on the basis of adjusted and updated test year sales for the year ended March 31, 2010).

5. That the proper aggregate base fuel factor for this proceeding is 2.511¢/kWh, excluding gross receipts tax, or 2.595¢/kWh, including gross receipts tax. The fuel factor shall be differentiated by class based on the voltage at which service is taken. The voltage-differentiated fuel factors, including gross receipts tax by class, and the approved base fuel factors to be established in this proceeding shall be, and hereby are as follows:

Residential	2.623 ¢/kWh
SGS & PA	2.622 ¢/kWh
LGS	2.602 ¢/kWh
NS	2.522 ¢/kWh
6VP	2.574 ¢/kWh
Outdoor Lighting	2.623 ¢/kWh
Traffic	2.622 ¢/kWh

6. That Rider A increments and decrements to the base fuel rates in subsequent fuel charge adjustment proceedings shall be calculated on a voltage-differentiated basis unless changed in DNCP's next general rate case, subject to the condition that the present Commission cannot bind a future Commission's ratemaking decisions in future DNCP fuel charge adjustment proceedings.

7. That the appropriate EMF for this proceeding is a decrement of 0.280¢/kWh, excluding gross receipts tax, or 0.289¢/kWh, including gross receipts tax, and this approved EMF shall be refunded to North Carolina retail customers on a uniform basis.

8. That the final net aggregate approved fuel factor is 2.231¢/kWh, excluding gross receipts tax, or 2.306¢/kWh, including gross receipts tax. The resulting total net voltage-differentiated fuel rates, including gross receipts tax, to be billed to DNCP's North Carolina retail customers during the 2011 fuel charge adjustment billing period shall be, and hereby are as follows:

Residential	2.334 ¢/kWh
SGS & PA	2.333 ¢/kWh
LGS	2.313 ¢/kWh
NS	2.233 ¢/kWh
6VP	2.285 ¢/kWh
Outdoor Lighting	2.334 ¢/kWh
Traffic	2.333 ¢/kWh

9. That for purposes of the EMF calculation and Rider B increments and decrements to the base fuel rates in subsequent fuel charge adjustment proceedings, monthly fuel costs shall begin to be measured in a voltage-differentiated manner as of January 1, 2011, subject to the condition that the present Commission cannot bind a future Commission's ratemaking decisions in future DNCP fuel charge adjustment proceedings.

10. That the service regulations proposed by the Company in its application, testimony, and exhibits filed in this proceeding, as modified by the changes agreed upon in Appendix B to the Stipulation shall be, and hereby are approved.

11. That within five business days after the date of this Order, DNCP shall file for Commission approval five copies of rate schedules designed to comply with Section 9(A) of the Stipulation and Appendix A attached thereto accompanied by calculations showing the revenues that will be produced by the rates for each schedule. Such filing shall include a schedule comparing the revenue produced by the filed schedules during the test period with the revenue that will be produced under the proposed settlement schedules, and a schedule illustrating the rates of return by class based on the revenues produced by the rates for each schedule. Such filing shall also include the Amended Agreement with the stated rates therein revised to be consistent with the rate changes approved herein for Schedule NS, and the Amended Agreement dated September 26, 2010, that will become effective with the effective date of Schedule NS.

12. That the Public Staff is hereby requested to file comments, and the other Stipulating Parties may file comments, on whether the proposed rate schedules filed by DNCP pursuant to Ordering Paragraph No. 11 comply with the provisions of this Order. Such comments shall be filed not later than two working days after the date DNCP files the proposed rate schedules.

13. That DNCP shall give appropriate notice of the approved rate increase by mailing a notice to each of its North Carolina retail customers during the billing cycle next following the effective date established by this Order. DNCP and the Public Staff shall jointly submit a proposed customer notice to the Commission for its review and approval before it is mailed to any customer.

14. That the construction of the VCHEC facility is needed to assure the provision of adequate public utility service in North Carolina and that the construction cost estimate and the construction schedule submitted by DNCP in this proceeding are reasonable and are hereby approved.

15. That DNCP shall submit a progress report and any revision in the construction cost estimate for VCHEC during each year of construction. Such reports shall be due annually on the date of the issuance of this Order for the 12 months ending the immediately preceding September 30th until construction is completed, at which time DNCP shall so notify the Commission by a filing in this docket.

16. That, with respect to the study DNCP is required to conduct for its next fuel charge adjustment proceeding to demonstrate that it has complied with Ordering Paragraph 1(e) of the Order Approving Transfer with Conditions issued April 19, 2005, in Docket No. E-22, Sub 418, the approach found reasonable in Docket No. E-22, Sub 456, shall be used for the study to be conducted by DNCP for the 2011 fuel charge adjustment proceeding.

17. That no change in the pricing methodology in the Amended Agreement on which Schedule NS has been based shall be made unless specifically allowed by this Commission nor shall the term of the Amended Agreement and Schedule NS be extended except as explicitly provided for in the Amended Agreement without prior approval of the Commission.

This 13th day of December, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

kh121310.01

DOCKET NO. E-35, SUB 38

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Western Carolina University for an Adjustment of Rates and Charges for Electric Services in North Carolina	))))	ORDER GRANTING GENERAL RATE INCREASE AND APPROVING STIPULATION

HEARD: Wednesday, December 9, 2009, at 7:00 p.m., in Liston B. Ramsey Center, Western Carolina University Campus, Cullowhee, North Carolina

Monday, March 1, 2010, at 2:00 p.m., in Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: William T. Culpepper, III, Presiding, and Commissioners Bryan E. Beatty and ToNola D. Brown-Bland

APPEARANCES:

For Western Carolina University:

Richard L. Kucharski, General Counsel, Western Carolina University, 1 University Way, H. F. Robinson Building Suite 520, Cullowhee, North Carolina 28723-9003

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 July 15, 2009, Western Carolina University (WCU or the Applicant) filed an application with the Commission seeking authority to increase its rates for electric service in its service area in Jackson County, North Carolina. The Applicant also filed the direct testimony of Kevin W. O'Donnell.

By Order issued on August 11, 2009, the Commission declared the above-captioned docket to be a general rate case, suspended the proposed rates, scheduled a public and evidentiary hearing in Cullowhee, North Carolina for December 9, 2009, and required customer notice.

On November 13, 2009, the Public Staff filed a motion requesting an extension of time to file testimony and a delay in the evidentiary hearing until a later date.

On November 20, 2009, the Commission issued an Order granting the Public Staff's motion. On that same date, WCU filed the Affidavit of Publication indicating that customer notice had been given in accordance with the Commission's Order.

On December 9, 2009, the Commission held the public hearing as originally scheduled and in accordance with the public notice. Mr. David Henderson, a customer of the Applicant, testified.

On February 11, 2010, WCU and the Public Staff filed a Stipulation. On that same date, the Public Staff filed the notice of affidavit and affidavit and exhibits of Sonja R. Johnson, Staff Accountant, Public Staff Accounting Division.

On February 25, 2010, WCU's witness, Kevin W. O'Donnell, filed WCU's proposed rate design for this docket and stated that the Public Staff had reviewed the rate design and agreed with the proposed rates.

By Order dated February 17, 2010, the Commission rescheduled the evidentiary hearing for March 1, 2010, which was held as scheduled in Raleigh, North Carolina. The Commission received the application of WCU and the Stipulation entered into between WCU and the Public Staff (the Parties). The Commission also admitted into evidence the affidavit and exhibits of Public Staff witness Johnson and the testimony and exhibits of WCU witness O'Donnell. The Commission requested that the Applicant file a late-filed exhibit detailing the following information: (1) the proposed percentage increase in overall revenue provided in the Stipulation, (2) the proposed percentage increase in residential rates that is reflected in the Stipulation, (3) the proposed percentage increase in commercial rates that is reflected in the Stipulation, and (4) the amount of increase for a 1,000 kWh bill for a residential customer under the proposed rates that are reflected in the Stipulation.

On March 10, 2010, the Applicant filed a late-filed exhibit containing the information requested by the Commission.

Finally, on March 29, 2010, WCU filed certain clarifications to the late-filed exhibit filed on March 10, 2010.

Based upon the verified application, the Commission's records, the Stipulation, customer testimony, the affidavit and testimony and exhibits received into evidence in this proceeding, and the record as a whole, the Commission makes the following:

ELECTRIC – RATE INCREASE

FINDINGS OF FACT

1. WCU is a State-supported institution of higher learning which owns and operates an electric distribution system. Although not a public utility, WCU is properly subject to the jurisdiction of the Commission pursuant to G.S. 116-35 with respect to the justness and reasonableness of its rates charged and services rendered to its retail electric customers in the Cullowhee area, Jackson County, North Carolina.

2. WCU does not generate its own electricity but buys its power wholesale from Duke Energy at rates approved by the Federal Energy Regulatory Commission (FERC).

3. WCU's last general rate case order was issued on December 10, 1993.

4. The test year for purposes of establishing rates in this docket is the 12-month period ended June 30, 2008.

5. WCU originally requested an increase in its electric rates that would produce $251,460 in additional annual revenues.

6. WCU is providing adequate electric service to its customers in its service area.

7. WCU gave sufficient and proper notice to its customers of the proposed increase in rates.

8. WCU and the Public Staff filed a Stipulation on February 11, 2010.

9. WCU's reasonable original cost rate base for purposes of this proceeding is $2,321,504.

10. WCU's balance of cost-free capital as of June 30, 2008, was $670,443.

11. WCU had plant in service, net of cost-free capital, of $4,177,272 at the end of the test year.

12. The reasonable balance of accumulated depreciation as of the end of the test year was $2,175,944.

13. The reasonable balance of working capital for purposes of this proceeding is $69,749.

14. The pro forma test year amount of depreciation expense reasonable and appropriate for purposes of this proceeding is $173,843. The pro forma test year amount of amortization expense reasonable and appropriate for purposes of this proceeding is $31,728.

15. WCU's total pro forma test year operating revenue deductions under present rates for purposes of this proceeding are $2,296,384.

ELECTRIC – RATE INCREASE

16. WCU's total pro forma test year operating revenues under present rates for purposes of this proceeding are $2,265,171.

17. The Parties agreed on an 8.11% overall rate of return. The stipulated overall rate of return reflects a hypothetical capital structure for WCU. The embedded cost of debt reflects the current rate for a tax-exempt revenue bond with an A2 rating, which is generally representative of the debt cost for WCU, and the return on common equity is based on an estimate using current financial market conditions.

18. A rate of return of 8.11% will allow WCU to recover its reasonable operating expenses and to make the necessary capital improvements to continue providing adequate service.

19. The Parties agreed that WCU is entitled to charges that will produce $219,487 in additional annual revenues.

20. The Parties agreed that of the $219,487 in additional annual revenues, $6,450 will be generated by the increases in fees recommended in the pre-filed direct testimony of WCU witness O'Donnell, and the remaining $213,037 will be generated by the proposed rates and charges for electric service filed by WCU on February 25, 2010.

21. In a late-filed exhibit filed on March 10, 2010, WCU provided rate schedules showing the revenues that will be produced by the rates for each rate schedule, which included a schedule comparing the revenue produced by the present rate schedules with the revenue that will be produced under the proposed rate schedules.

22. The overall percentage increase in rates agreed to by the Applicant and the Public Staff is 9.68%.

23. The rates and revenues agreed to by the Applicant and the Public Staff result in an increase in residential rates of 8.46%.

24. The rates and revenues agreed to by the Applicant and the Public Staff result in an increase in commercial rates of 8.15%.

25. The rates and revenues agreed to by the Applicant and the Public Staff result in an increase of 8.25% for 1,000 kWh billed for residential customer usage.

26. The Parties agreed that all pre-filed Public Staff and WCU testimony and exhibits, including any supplemental testimony filed by the Applicant in support of the Stipulation, would be introduced into evidence without objection, and the parties thereto waived their respective right to cross-examine all witnesses with respect to all such pre-filed testimony and exhibits.

27. The Parties agreed to waive appeal of a Final Order of the Commission incorporating the matters stipulated.

28. The Parties acknowledged that the Stipulation resulted from extensive negotiations and compromise. Thus, the agreements reached do not necessarily reflect the respective Parties' beliefs as to the proper treatment or level of the matters cited. Except as needed to carry out the terms of a Commission Order based on the Stipulation, the Parties agreed that none of the positions, treatments, figures, or other matters reflected in the Stipulation should have any precedential value, nor should they otherwise be used in any subsequent proceedings before the Commission or any other regulatory body as proof of the matter at issue.

29. The proposed rate schedules filed by WCU on February 25, 2010, and the recommended fees contained in the pre-filed direct testimony of WCU witness O'Donnell are just and reasonable and are designed to produce an increase in annual revenues of $219,487 based upon the test year. The proposed rates include a base purchased power factor equal to $0.04408 per kWh which is also approved as just and reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-5

The evidence supporting these Findings of Fact is contained in the verified application; the affidavit, testimony, and exhibits of the Public Staff and the Applicant; and the Commission's records. These Findings of Fact are essentially informational and uncontradicted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence supporting this Finding of Fact is contained in the testimony offered at the customer hearing and the Commission's records. One customer, Mr. David Henderson, appeared at the hearing and offered testimony regarding his ethical beliefs relating to Duke Energy's proposed coal-fired power plant. The witness stated that he opposed a rate hike if it would go to a company that proposed building a plant that could potentially harm the environment. However, the witness did not state that he had any service-related complaints. Additionally, the Public Staff received one e-mail from a WCU customer against the proposed rate increase. In conclusion, there is nothing in the record to support a finding that the level of service provided by WCU is less than adequate.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence supporting this Finding of Fact is contained in the Affidavit of Publication filed by the Applicant on November 20, 2009, indicating that customer notice had been given in accordance with the Commission's Order. No one refuted the Applicant's affidavit, and the Commission concludes that the Applicant gave sufficient and proper notice to its customers of the proposed increase in rates.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 8-29

The evidence supporting these Findings of Fact is contained in the verified application; the affidavit, testimony, and exhibits of the Public Staff and the Applicant; the Stipulation between the Parties; the late-filed exhibit of the Applicant; and the entire record in this proceeding.

ELECTRIC – RATE INCREASE

On February 11, 2010, WCU and the Public Staff filed a Stipulation agreeing to and recommending an increase in revenues of $219,487. Also on that date, the Public Staff filed the notice of affidavit and affidavit of Public Staff Accountant Johnson, which supported the terms of the Stipulation.

On February 25, 2010, the Applicant filed schedules containing the proposed rates and charges designed to produce the stipulated revenue requirement.

The Commission concludes that the Stipulation between the Applicant and the Public Staff is reasonable and appropriate for purposes of this proceeding and that the proposed rates set forth in the schedules filed by WCU on February 25, 2010, and the fees recommended in the pre-filed direct testimony of WCU witness O'Donnell should be approved.

The Commission notes that there is a pending request by WCU for a purchased power adjustment in Docket No. E-35, Sub 39. The Commission will rule on this request by separate order.

IT IS, THEREFORE, ORDERED as follows:

1. That WCU is authorized to adjust its rates and charges and fees to increase its annual gross revenues by $219,487, effective for service rendered in the billing cycle associated with each bill rendered on or after April 15, 2010.

2. That WCU is required to file tariff sheets not later than ten (10) days from the date of this Order reflecting the rates and fees designed to produce the increase in revenues as approved herein; and

3. That WCU and the Public Staff shall jointly prepare and file a proposed customer notice addressing both the rate increase approved herein as well as any rate impact on customers that would result from Commission approval of any recommendation by the Parties in Docket No. E-35, Sub 39, effective for service rendered in the billing cycle associated with each bill rendered on or after April 15, 2010.

ISSUED BY ORDER OF THE COMMISSION.
This the 8th day of April, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

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DOCKET NO. E-2, SUB 977

In the Matter of		
Application by Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc., for Approval of Demand Side Management and Energy Efficiency Cost Recovery Rider Pursuant to G.S. 62-133.9 and Commission Rule R8-69	)	ORDER APPROVING DSM/EE RIDER AND REQUIRING FILING OF PROPOSED CUSTOMER NOTICE

HEARD: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina on Wednesday, September 22, 2010, at 10:38 a.m.

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

Lucy E. Edmondson, 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

For the North Carolina Sustainable Energy Association:

Kurt Olson, Staff Counsel, 1111 Haynes Street, Suite 109, Raleigh, North Carolina 27608

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. 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 Rule R8-69, this rider consists of the utility's forecasted costs 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.

Pursuant to G.S. 62-133.9 and Commission Rule R8-69, on June 4, 2010, Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc. (PEC or the Company), filed an application and the associated testimony of Robert P. Evans and Julie Hans for the approval of a DSM/EE cost recovery rider to recover reasonable and prudent forecasted DSM/EE costs, carrying costs, incremental administrative and general (A&G) costs, 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 EMF of its costs, including net lost revenues and an additional incentive, incurred up to 30 days prior to the hearing in this proceeding.

On June 11, 2010, the Commission issued an Order scheduling a public hearing in this matter on September 22, 2010 immediately following the 9:00 a.m. hearing in Docket No. E-2, Sub 974, establishing discovery guidelines, providing for intervention and testimony by other parties, and requiring public notice.

On June 9, 2010, the Attorney General filed a notice of intervention, which is recognized pursuant to G.S. 62-20. The intervention of the Public Staff is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e). On June 14, 2010, the North Carolina Sustainable Energy Association (NCSEA) filed a petition to intervene, which was allowed June 17, 2010. On June 29, 2010, the Carolina Utility Customers Association, Inc. (CUCA) filed a petition to intervene, which was allowed July 2, 2010.

On August 20, 2010, PEC filed the supplemental direct testimony and exhibits of Robert P. Evans. On September 2 and September 10, 2010, the Public Staff filed motions for an extension of time to file its direct testimony, which the Commission allowed by Orders issued September 3 and September 10, 2010, respectively.

On September 14, 2010, the Public Staff filed the affidavits of Michael C. Maness and Jack L. Floyd. Also on September 14, 2010, PEC filed affidavits of publication of the required notices of the proceeding. On September 17, 2010, PEC filed the revised supplemental testimony of Robert P. Evans.

The case came on for hearing as scheduled on September 22, 2010. The prefiled testimony of PEC witnesses Evans and Hans was received into evidence, as well as the supplemental and revised supplemental testimony of PEC witness Evans; Evans Exhibit Nos. 1-11 and Workpapers Sections B, C, and D; Evans Supplemental Exhibit Nos. 1-11 and Supplemental Workpapers B-2, B-6, B-8, B-9, and B-10; and Evans Revised Supplemental Exhibit Nos. 1-11; and the witnesses presented direct testimony on behalf of the Company. The affidavits of Michael C. Maness and Jack L. Floyd were received into evidence. No other party presented witnesses and no public witnesses appeared at the hearing. On September 24, 2010 and October 22, 2010, PEC filed several late-filed exhibits per the Commission's oral order from the bench during the evidentiary hearing. On October 28, 2010, PEC and the Public Staff filed a Joint Proposed Order.

Based upon PEC's verified application, 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 North Carolina Utilities Commission (NCUC) 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, 2009 through March 31, 2010.

3. The rate period for the purposes of this proceeding is the 12-month period, December 1, 2010 through November 30, 2011.

4. Pursuant to Commission Rule R8-69(b)(2), PEC is permitted to include in its DSM/EE EMF 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, which is April 1, 2010 through July 31, 2010.

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; Residential Low Income-NES; CIG EE; Residential Lighting; 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 $2,673,216 for the test period, $690,245 for the prospective period, and $3,369,335 for the rate period. Additionally, as requested by the Commission in its November 25, 2009 Order in Docket No. E-2, Sub 951 (Sub 951 Order), PEC has provided data regarding the reach and extent of its general DSM/EE education and awareness initiatives. It is appropriate for PEC to recover these incremental A&G costs. The prospective and rate period costs will be subject to further review in PEC's next annual DSM/EE rider proceeding.

7. PEC requested the recovery of net lost revenues and program incentives in the amount of $1,012,434 for the test period, $898,224 for the prospective period (net of the prior proceeding's prospective period), and $9,868,705 for the rate period. PEC's proposed recovery

of net lost revenues and program incentives are consistent with the Commission's June 15, 2009 Order in Docket No. E-2, Sub 931 (Sub 931 Order), and are appropriate for recovery in this proceeding, with the prospective and rate period costs subject to further review in PEC's future annual DSM/EE rider proceedings.

8. For purposes of its DSM/EE EMF rider, PEC's reasonable and prudent North Carolina retail test year amounts, consisting of its amortized DSM/EE operations and maintenance (O&M) costs, amortized incremental A&G costs, carrying charges, net lost revenues, and program incentives, are $11,364,351. Subject to review in PEC's next annual DSM/EE rider proceeding, PEC's North Carolina retail DSM/EE program amounts for the prospective period, consisting of its amortized O&M costs, amortized incremental A&G costs, carrying charges, and net lost revenues, are $6,047,850. The sum of these figures has been reduced by $1,614,086, the revenue requirement for the period April 1, 2009 to July 31, 2010, to avoid double counting amounts recognized in Docket No. E-2, Sub 951. Therefore, $15,798,115 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, PEC's reasonable and appropriate estimate of its 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 is $43,381,247, and this is the appropriate amount to use to develop the DSM/EE revenue requirement.

9. The appropriate DSM/EE EMF riders for the Residential, General Service, and Lighting rate classes are decrements of 0.001 cents per kilowatt hour, 0.010 cents per kilowatt hour, and 0.011 cents per kilowatt hour, respectively.[1]

10. The appropriate DSM/EE rates to be charged by PEC during the rate period for the Residential, General Service, and Lighting rate schedules are increments of 0.192 cents per kilowatt hour, 0.132 cents per kilowatt hour, and 0.077 cents per kilowatt hour, respectively.

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; in PEC's Late-Filed Exhibits, and in various Commission orders.

In direct testimony filed on June 4, 2010, PEC witness Evans testified that PEC is requesting the recovery of costs associated with the following DSM/EE programs: DSDR;

[1] These rates, as well as those discussed in the Evidence and Conclusions for these Findings of Fact, all exclude gross receipts taxes and the NCUC regulatory fee.

EnergyWise™ CIG Demand Response; Residential Home Advantage; Residential Home Energy Improvement; Residential Low Income-NES; CIG Energy Efficiency; Residential Lighting; 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, Residential EnergyWise™, DSDR, and CIG Demand Response. Witness Evans explained that these programs consisted of event driven measures where resulting revenue losses are a function of their deployment and cannot be accurately predicted in advance. Accordingly, witness Evans testified that PEC would request net lost revenue recoveries for these programs based on their actual rather than estimated deployments when such actual information becomes available and has been analyzed by the Company.

Public Staff witness Floyd agreed that, for purposes of this proceeding, PEC has requested recovery of costs related to the following DSM and EE programs: DSDR; EnergyWise™ CIG Demand Response; Residential Home Advantage; Residential Home Energy Improvement; Residential Low Income-NES; CIG Energy Efficiency; Residential Lighting; Residential Appliance Recycling; Residential Solar Water Heater Pilot; and CFL Pilot. Further, witness Floyd stated 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 these programs in Docket Nos. E-2, Subs 908, 926, 927, 928, 935, 936, 937, 938, 950, 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.

In PEC witness Hans' direct testimony filed on June 4, 2010, witness Hans testified that PEC published General Awareness Advertising in 10 different publications in PEC's service territory. Witness Hans stated that such ads were published 46 times, resulting in the energy savings message being viewed nearly 4 million times. Witness Hans explained that 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 and that more than 530,000 customers received an email from PEC during 2009 and 2010 directing them to visit the CHER website and to complete the energy audit. According to witness Hans, as of March 2010, more than 15,000 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 had received more than 150,000 visits during the test year and that more than 10,000 visits were made to PEC's Energy Efficiency World website, which targets school-age children. Witness Hans stated that PEC representatives also attended 40 community events across PEC's service territory to educate customers about PEC's EE programs and to share energy savings tips and that more than 3,700 fliers were distributed at these events.

PEC witness Evans stated in his direct testimony filed on June 4, 2010, that 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 stated that the A&G costs in this proceeding have been assigned to these categories based upon forecasted DSM and EE costs for 2011. PEC's incremental A&G costs were provided on PEC witness Evans' Exhibit No. 1. The incremental A&G costs for the test period are $2,673,216, $690,245 for the prospective period, and $3,369,335 for the rate period.

The incremental general education and awareness costs, which are a part of the aforementioned A&G costs, were identified on page 5 of PEC witness Evans' direct testimony. Such costs for the test period are $830,811, $435,214 for the prospective period, and $1,332,690 for the rate period.

Public Staff witness Floyd noted in his affidavit that in the Sub 931 Order, the Commission stated that, as a general rule, A&G costs not directly related to an approved DSM or EE program should be deferred and amortized over a period not to exceed three years. The Commission further directed the Public Staff to monitor and review PEC's A&G costs on an ongoing basis, with particular emphasis on the effectiveness of PEC's General Education and Awareness (GEA) programs, and to report its findings to the Commission during PEC's future DSM/EE rider proceedings.

Witness Floyd testified that he has reviewed PEC's A&G costs included in Evans' Supplemental Exhibit No. 1 and it appeared that PEC did not assign any A&G costs to specific DSM or EE programs. Witness Floyd observed that in PEC's portfolio of DSM and EE programs, A&G costs have become more frequently associated with management of the overall portfolio of programs than with a specific program. As a result, all A&G costs are now being amortized over three years and allocated to DSM and EE programs based on the rate period program costs and to customer classes based on the rate period revenue requirements before program performance incentives (PPIs) and lost revenues. Witness Floyd stated that he has reviewed the allocations as proposed by PEC and believes the allocation methodology employed to be reasonable for allocating and recovering A&G costs.

Witness Floyd observed that in its Sub 951 Order, the Commission recognized the difficulty in measuring the benefits related to GEA initiatives, which, for the most part, do not directly generate energy savings. The Commission noted that such initiatives are instead designed to promote and convey information to customers who might either choose to participate in a specific PEC DSM or EE program, or otherwise invest in other EE measures on their own. The Commission also listed several metrics that could be used to evaluate the effectiveness of GEA initiatives.

ELECTRIC – RATE SCHEDULE/RIDERS/SERVICE RULES AND REGULATIONS

Witness Floyd stated that in a response to a Public Staff data request, PEC provided some quantitative data on specific GEA initiatives offered during the test period, April 1, 2009 through March 31, 2010. That information is summarized below:

1. CHER online surveys, that provided targeted energy savings tips based on customer responses, referred 15,000 participants from July 2009 through March 2010 to the Residential Home Energy Improvement Program.

2. Energy Efficiency World, internet-based resources for school classroom activities, had 10,000 first time and repeat visitors.

3. Save the Watts website, which provides general EE recommendations and resources, had 150,000 first time visitors.

4. 314,000 targeted emails were delivered encouraging customers to participate in the CHER, resulting in 3.1% of those customers taking advantage of the CHER.

5. Materials and information were distributed at 40 community sponsored events.

6. Representatives promoting EE participated in 51 trade shows and contractor training events in North and South Carolina with approximately 4,600 participants.

7. Advertisements promoting EE appeared in various newspapers across the PEC service territory totaling approximately four million impressions.

8. Approximately 9,000 brochures and flyers, including bill inserts, promoting PEC's DSM or EE programs, were distributed.

Public Staff witness Floyd testified that he had reviewed PEC's application and responses to data requests and believes PEC is making a reasonable effort to communicate with and educate its customers regarding energy usage and awareness. In Session Law 2007-397 (Senate Bill 3), the General Assembly amended G.S. 62-2 to, among other things, further encourage and promote the development of EE. Witness Floyd stated that he believes these GEA initiatives help promote the public policy of encouraging EE in North Carolina, as set out in Senate Bill 3; that PEC has made reasonable attempts to target these initiatives so that they reach its customers, and as such, recommended that PEC be allowed to recover the reasonable and prudent costs related to these GEA initiatives. Witness Floyd stated that the Public Staff would continue to evaluate these costs and allocations in future cost recovery proceedings.

Public Staff witness Floyd recommended that PEC consider how GEA costs might be incorporated into evaluating and quantifying the effectiveness of the GEA initiatives. He further proposed that PEC consider how it might incorporate these costs into its evaluation of the cost-effectiveness of individual programs or its overall portfolio of programs. In response to questions from Chairman Finley, PEC witness Evans agreed with witness Floyd that costs of the direct education awareness efforts associated with a program should be included in the cost-effectiveness test for that program. However, witness Evans stated that it would be difficult and likely inappropriate to make such an assignment to general unrelated program costs, and would likely distort the actual program results. Witness Evans explained that allocating unrelated costs to a program could distort the results of the cost-effectiveness tests for the program.

No party opposed the recovery of PEC's reasonable and prudent GEA expenditures described in witness Floyd's affidavit and in PEC's testimony. Consequently, the Commission finds and concludes it is appropriate for PEC to recover its reasonable and prudent incremental A&G costs, as set forth hereinabove. The prospective and rate period costs will be subject to further review in PEC's next annual DSM/EE rider proceeding. The Commission further concludes that PEC should continue to evaluate the effectiveness of its GEA initiatives and, in the next DSM/EE rider proceeding, specifically address whether it is appropriate to incorporate these GEA costs (and associated A&G costs) into the cost-effectiveness tests and evaluations of the currently approved programs and all future programs. The Public Staff is requested to review such information, as well as continue to monitor and review PEC's A&G expenses as required by the Sub 951 Order, and report its findings and recommendations related to all such matters to the Commission in PEC's future DSM/EE rider proceedings.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 7 THROUGH 10

The evidence for these findings of fact can be found in the testimony and exhibits of PEC witness Evans and in the affidavits of Public Staff witnesses Floyd and Maness.

In PEC witness Evans' revised supplemental direct testimony and exhibits filed on September 17, 2010, witness Evans calculated PEC's North Carolina retail test period DSM/EE net lost revenues and program incentives as $1,012,434. He calculated PEC's North Carolina retail prospective period DSM/EE net lost revenues and program incentives (net of the prior prospective period total) as $898,224. He also calculated PEC's North Carolina retail rate period DSM/EE net lost revenues and program incentives as $9,868,705.

Further, PEC witness Evans calculated PEC's North Carolina retail test year amounts, consisting of its amortized DSM/EE O&M costs, amortized incremental A&G costs, carrying charges, net lost revenues, and program incentives to be $11,364,351. For the prospective period, witness Evans calculated the total to be $6,047,850. The sum of these figures has been reduced by $1,614,086, the revenue requirement for the period April 1, 2009 to July 31, 2010, to avoid double counting amounts, as provided by the Sub 951 Order. Therefore, witness Evans stated that $15,798,115 is appropriate to use to develop the DSM/EE EMF revenue requirement. Witness Evans also calculated PEC's estimate of its 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, as $43,381,247.

In PEC witness Evans' revised supplemental direct testimony filed on September 17, 2010, witness Evans calculated the DSM/EE EMF rider for Residential, General Service, and Lighting rate classes for the rate period to be decrements of 0.001 cents per kilowatt hour, 0.010 cents per kilowatt hour, and 0.011 cents per kilowatt hour, respectively, excluding gross receipts taxes and the North Carolina regulatory fee. He also calculated the DSM/EE rates for Residential, General Service, and Lighting rate classes for the rate period to be increments of 0.192 cents per kilowatt hour, 0.132 cents per kilowatt hour, and 0.077 cents per kilowatt hour, respectively, excluding gross receipts taxes and the NCUC regulatory fee.

In Public Staff witness Maness' affidavit, he stated that G.S. 62-133.9(d) allows a utility to petition the Commission for approval of an annual rider to recover (1) the reasonable and prudent costs of new DSM and EE measures and (2) other incentives to the utility for adopting and implementing new DSM and EE measures. Commission Rule R8-69, which was adopted by the Commission pursuant to G.S. 62-133.9(h), sets forth the general parameters and procedures governing approval of the annual rider, including (1) provisions for both a DSM/EE rider to recover the estimated costs and incentives applicable to the "rate period" in which that DSM/EE rider will be in effect, and a DSM/EE EMF rider to recover the difference between the DSM/EE rider in effect for a given test period and the actual recoverable amounts incurred during that test period; (2) allowance for inclusion in the DSM/EE EMF rider of the net under- 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 next year's proceeding; (3) consideration of the appropriateness of the recovery of net lost revenues as an incentive; (4) provision for deferral accounting for net under- and over-recoveries; and (5) provisions for interest or return on the deferral account and on refunds to customers.

Further, Public Staff witness Maness stated that the method by which PEC has calculated its proposed rates in this proceeding is the Cost Recovery and Incentive Mechanism for Demand-Side Management and Energy Efficiency Programs (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 the same docket. The Mechanism includes the following components:

(1) Application for Approval of Programs – This part of the Mechanism delineates certain steps and criteria PEC will follow when evaluating a potential DSM or EE program, including qualitative and cost-effectiveness screening, and sets forth requirements for continued monitoring of approved programs' cost-effectiveness test results.

(2) Cost Recovery – Pursuant to this portion of the Mechanism, PEC is allowed to recover reasonable and prudent DSM and EE program costs. PEC is allowed to defer incurred DSM/EE program O&M and A&G expenses, with amortization over periods of time not to exceed 10 and 3 years, respectively. Additionally, the Company is allowed to recover the capital costs of capitalized DSM and EE assets, as well as carrying costs related to deferred charges.

(3) Lost Revenues - This section of the Mechanism allows PEC to recover net lost revenues as an incentive, but generally limits recovery to the first 36 months after an applicable DSM or EE measurement unit is installed. Additionally, certain general programs and measures, as well as research and development activities, are ineligible for recovery of net lost revenues, along with pilot programs, unless PEC requests and the Commission approves such recovery at the time of program approval. Net lost revenue recovery also ceases upon the implementation of new rates approved by the Commission in a general

rate case or similar proceeding, and must be offset by any increase in revenue due to increased demand or energy consumption by PEC customers attributable to any activity by PEC's public utility operations.

(4) PPI - This section of the Mechanism provides for the recovery by PEC of a performance incentive for the implementation and operation of cost-effective new DSM and EE programs that achieve verified energy and peak demand savings. The same limitations regarding certain general programs and measures, research and development activities, and pilot programs as set forth in the Lost Revenues section are also applicable to the PPI, along with a restriction barring recovery of the PPI for programs that become non-cost-effective. The PPI is based on the net savings of each program or measure as calculated using the Utility Cost Test, and is equal to 8% of net savings for DSM programs and measures or 13% for EE programs and measures.

The Mechanism's terms and procedures are to be reviewed by PEC and other parties at least every three years to ensure that they continue to be appropriate; any changes in the terms and conditions would only be applied prospectively.

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. Review of this sample, which was still ongoing at the time of the filing of witness Maness' affidavit but has since been completed, was intended to test whether the costs included by the Company in the riders are valid costs of approved DSM and EE programs, or administrative costs supporting those programs.[1] Further, witness Maness stated that performing 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.

Public Staff witness Maness stated that his investigation, including the Public Staff's sampling procedure, was concentrated primarily on costs and incentives related to the April 2009 – March 2010 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 2010 – November 2011) component of the riders. Actual costs and incentives applicable to the rate period, as well as costs and incentives applicable to the April-July 2010 "prospective" period, which are also included in the DSM/EE EMF riders, would be subject to detailed review in future DSM/EE cost recovery proceedings.

Public Staff witness Maness stated that his investigation of PEC's filing indicates that the Company generally has calculated the proposed riders in accordance with the methods set forth

[1] The Public Staff has completed the review of the sample and has found no evidence that the costs included by the Company were not valid costs of approved DSM and EE programs.

in the approved Mechanism for recovery of costs, net lost revenues, and the PPI. However, in the course of his review, he identified the following relatively minor adjustments that he recommended to be made to the calculations:

(1) The "gross-up" of the DSM/EE and DSM/EE EMF riders included by the Company to provide for recovery of the Residential Energy Conservation Discount (RECD) should be removed, pursuant to the Commission's June 9, 2010 Order Approving Revised Tariff in Docket No. E-2, Sub 789.

(2) The allocation of non-DSDR-related A&G and carrying costs between rate classes for purposes of the EE component of the DSM/EE EMF rider should be changed to reflect allocation by assigned O&M costs, rather than billed kilowatt hours.

(3) The order of calculating the "gross-up" of the riders to provide for recovery of gross receipts tax (GRT) and the North Carolina regulatory fee (NCRF), on the one hand, and uncollectibles, on the other, should be reversed, so that the gross-up for GRT and the NCRF is performed first.

(4) The average period used in the calculation of interest on the over-recovery of DSM/EE costs should be increased to 14 months from the 10 months utilized by the Company, to reflect the midpoint between the beginning of the over-recovery period (August 1, 2009) and the end of the refund period (November 30, 2011).

PEC witness Evans calculated the adjustments recommended by Public Staff witness Maness in his revised supplemental direct testimony filed on September 17, 2010. Witness Evans stated the adjustments resulted in both the shifting of some costs between rate classes and a $34,468 reduction in revenue requirements. In addition, as a result of the investigations associated with the discovery process, it was determined that carrying costs and related income taxes were understated by $11,639. The associated adjustment resulted in an increase in DSM/EE revenue requirements. The net impact of the aforementioned adjustments, a $22,828 reduction in overall revenue requirements, has been recognized in the Company's proposed rates.

Public Staff witness Floyd stated that under G.S. 62-133.9, Commission Rule R8-69, and the Sub 931 Order, PEC is allowed to recover through the DSM/EE rider all reasonable and prudent costs appropriately estimated to be incurred during the current rate period for DSM and EE programs that have been approved by the Commission under Commission Rule R8-68. The DSM/EE EMF rider reconciles the difference between the reasonable and prudent costs actually incurred during the applicable test period and the revenue realized during the test period from the DSM/EE riders in effect during the test period.

Public Staff witness Floyd also reviewed PEC's calculations of the DSM/EE and DSM/EE EMF riders for each customer class. Witness Floyd stated that based on his review of the initial program approval filings and the previous DSM/EE cost recovery proceedings, the program costs included in the prospective rate periods appear to be reasonable and appropriate. Witness Floyd noted that these costs would continue to be reviewed under future DSM/EE rider proceedings for both reasonableness and prudence and ultimately will be trued-up using the actual energy and capacity savings determined by the measurement and verification process.

The Commission finds that no party opposed PEC's proposed recovery of net lost revenues and program incentives; that such proposed recovery is consistent with the Commission's Sub 931 Order; and that net lost revenues and program incentives are appropriate for recovery in this proceeding, with the prospective and rate period costs subject to further review in PEC's future annual DSM/EE rider proceedings. The Commission concludes that PEC has, with the adjustments proposed in the revised supplemental testimony of PEC witness Evans, complied with G.S. 133.9, Commission Rule R8-69, and the Sub 931 Order with regard to calculating costs and incentives for the test, prospective, and rate periods at issue in this proceeding.

Therefore, the Commission concludes that for the purposes of the DSM/EE EMF rider to be set in this proceeding, PEC's reasonable and prudent North Carolina retail test year amounts, consisting of its amortized DSM/EE O&M costs, amortized incremental A&G costs, carrying charges, net lost revenues, and program incentives, are $11,364,351. The Commission further concludes that subject to review in PEC's next annual DSM/EE rider proceeding, PEC's North Carolina retail DSM/EE program amounts for the prospective period, consisting of its amortized O&M costs, amortized incremental A&G costs, carrying charges, and net lost revenues, are $6,047,850. The sum of these figures has been reduced by $1,614,086, the revenue requirement for the period April 1, 2009 to July 31, 2010, to avoid double counting amounts recognized in Docket No. E-2, Sub 951. Therefore, the Commission finds that $15,798,115 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, amortized incremental A&G costs, carrying charges, net lost revenues, and program incentives is $43,381,247, and this is the appropriate amount to use to develop the DSM/EE revenue requirement.

Based on the testimony of witness Evans, the affidavit of witness Maness, and the entire record in this proceeding, the Commission finds and concludes that the DSM/EE EMF riders as proposed by PEC in the September 17, 2010 second supplemental direct testimony of PEC witness Evans for the Residential, General Service, and Lighting rate classes are appropriate. The Commission further concludes that the DSM/EE rates proposed by PEC in the September 17, 2010 second 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.

IT IS, THEREFORE, ORDERED as follows:

1. That the appropriate DSM/EE EMFs for the Residential, General Service and Lighting rate classes are decrements of 0.001 cents per kilowatt hour, 0.010 cents per kilowatt hour, and 0.011 cents per kilowatt hour, respectively, excluding gross receipts tax and the NCUC regulatory fee.

2. That the appropriate DSM/EE rates to be charged by PEC during the rate period for the Residential, General Service and Lighting rate classes are increments of 0.192 cents per kilowatt hour, 0.132 cents per kilowatt hour, and 0.077 cents per kilowatt hour, respectively, excluding gross receipts tax and the NCUC regulatory fee.

3. That the total proposed DSM/EE annual riders including PEC's proposed DSM/EE EMF riders for the Residential, General Service and Lighting rate classes are increments of 0.191 cents per kilowatt hour, 0.122 cents per kilowatt hour, and 0.066 cents per kilowatt hour, respectively, excluding gross receipts tax and the NCUC regulatory fee.

4. That PEC shall file appropriate rate schedules and riders with the Commission in order to implement these adjustments. Such rates shall be effective for service rendered on or after December 1, 2010.

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 974, 976, and 977, and PEC shall file such proposed notice for Commission approval as soon as practicable.

6. That PEC shall continue to evaluate the effectiveness of GEA initiatives and, in the next DSM/EE rider proceeding, shall specifically address whether it is appropriate to incorporate GEA costs (and associated A&G costs) into the cost-effectiveness tests and evaluations of PEC's currently approved programs and all future programs. Further, the Public Staff shall review such information, as well as continue to monitor and review PEC's A&G expenses as required by the Sub 951 Order, and report its findings and recommendations related to all such matters to the Commission in PEC's future DSM/EE rider proceedings.

ISSUED BY ORDER OF THE COMMISSION
This the 17th day of November, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

fh111710.01

DOCKET NO. E-2, SUB 979

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Request of Progress Energy Carolinas, Inc., for Approval of Residential Service (Experimental) SunSense Solar Rebate Rider and Waiver of Certain Provisions of Commission Rule R8-66) ORDER APPROVING RIDER AND GRANTING WAIVER REQUEST

ELECTRIC – RATE SCHEDULE/RIDERS/SERVICE RULES AND REGULATIONS

BY THE COMMISSION: On July 1, 2010, Progress Energy Carolinas, Inc. (PEC), filed a request for approval of its Residential Service (Experimental) SunSense Solar Rebate Rider SSR-1 (Rider). The purpose of the Rider is to allow PEC to acquire renewable energy certificates (RECs) to assist it in complying with the North Carolina Renewable Energy and Energy Efficiency Portfolio Standard (REPS) requirements. PEC requests a waiver of certain provisions of Commission Rule R8-66 with regard to the registration and reporting requirements for participants receiving service under the Rider.

Under the Rider, eligible residential customers who install new rooftop-mounted solar photovoltaic (PV) electric generating systems will receive a one-time participation payment of $1,000 per kW based upon the alternating current (AC) capacity rating of the PV generating system and monthly bill credits in return for the RECs produced by the PV generating system. The Rider is limited to new applications totaling 1,000 kilowatts (kW) in a calendar year and will be available to new applicants until Decmeber 31, 2015. Prior to installation of a PV system, a participant must submit a Residential Solar Photovoltaic (PV) Program Application Form (Application) describing the system, its costs, and the participant's billing arrangements.

Qualifying PV systems must have an AC capacity rating of at least 2 kW, but no greater than 10 kW. Within 90 days of PEC's acceptance of the Application, the participant must complete the installation, submit a certificate of completion indicating that the system is operational, and request that metering be installed to support net metering. The participant must receive service under Residential Service Time-of-Use Schedule R-TOUD and Net Metering for Renewable Energy Facilities Rider NM. The initial contract period under the Rider will be 60 months, and is renewable thereafter for successive one-year periods. The participant may terminate service at any time with 60 days' prior written notice to PEC; however, the participant will forfeit any monthly credits thereafter, and must pay an early termination charge.

PEC proposes to assist participants with their compliance with the Commission's rules and requirements regarding the interconnection, registration, and reporting of RECs for the new renewable energy facilities installed as a result of this Rider. Specifically, PEC proposes that:

- The requirements for interconnecting net-metered customers, including the request for interconnection and applicable Interconnection Agreement provisions, be incorporated and administered directly in the documents for Rider participants. In this regard, participants will be required to provide sufficient detail in the Application to allow PEC to verify that the interconnection will comply with all requirements to ensure safe operation, including IEEE 1547 and UL 1741 requirements. Upon receipt of the certificate of completion, PEC will record the location of the participant's generation to acknowledge any future implications to grid operations. The participant will not be required to pay the $100 non-refundable processing fee required in the fast track application process.

- Participants continue to file a Report of Proposed Construction pursuant to Commission Rule R8-65. PEC will provide participants with a sample submittal letter to assist in fulfilling this requirement. PEC states that the Application should simplify the submittal process, as it contains much of the information required to be submitted pursuant to Commission Rule R8-64(b)(1).

- Participants be exempt from holding individual accounts in the North Carolina Renewable Energy Tracking System (NC-RETS) in order to earn RECs. Instead, PEC requests that it be allowed to report the total number of RECs produced by participants on an annual basis. Each year, PEC will upload the total number of RECs provided by Rider SSR-1 participants into NC-RETS under one designation, much like energy efficiency REC reporting. For measurement and verification and auditing purposes, PEC will maintain corresponding participation records, including actual Rider participation as captured in its billing system. All supporting documentation to validate participants and participation levels will be maintained by PEC and provided for Commission and Public Staff review upon request. Participants are not precluded from registering with the Commission and participating in NC-RETS on an individual basis after the initial five-year term.

PEC requests a waiver of certain provisions of Commission Rule R8-66 with regard to the registration and reporting requirements for participants receiving service under the Rider. These waiver requests will only apply to generation owners participating and receiving service under the Rider. PEC requests that this process, including annual registration updates, be waived, and that PEC be permitted to maintain relevant information on behalf of participants while they receive service under the Rider. More specifically, PEC requests that:

- Participants be exempt from the Rule R8-66(b)(1) requirement to file with the Commission a Registration Statement. PEC states that all relevant participant data will be collected and maintained through PEC's administration and records.

- Participants be exempt from the Rule R8-66(b)(2) requirement to file with its Registration Statement a copy of Form EIA-923 Schedules 1, 5, 6 and 9 since participants will not have sufficient capacity to require such a filing with the United States Department of Energy.

- Participants be exempt from the Rule R8-66(b)(3) and (b)(4) requirement to certify annually compliance with all federal and state laws, regulations, and rules for the protection of the environment and conservation of natural resources, and that the facility is operated as a renewable energy facility. Since PEC requires that the participant verify that the generation facility complies with all such requirements as a condition of service under the Rider, PEC requests a presumption of compliance for participants, and that the participants be relieved of this filing requirement.

- Participants be exempt from the Rule R8-66(b)(5) requirement to file a compliance statement annually to certify that any RECs sold to an electric power supplier will not be remarketed or resold for any purpose and that the purchaser of RECs be identified. Because PEC will be receiving all RECs generated for the first five years and uploading the energy production data for these same RECs directly into an NC-RETS account, rather than allowing individual participants to create their own accounts, PEC requests that service under the Rider be deemed as a form of compliance with this certification requirement.

- Participants be exempt from the Rule R8-66(b)(6) and (b)(7) requirements that renewable facility owners consent to audits, verify the Registration Statement, and signify that they have authority to submit the required information to the Commission, since PEC will receive signed and verified information from participants, and the Commission will have full access, upon request, to PEC's records on the Rider and its participants. In addition, PEC, as administrator, requests that it be permitted to forego the need to meter each generator individually and that it be allowed to utilize the PVWatts™ Solar Calculator developed by the National Renewable Energy Laboratory for estimating the annual generation from participants, as permitted in Commission Rule R8-67(g)(2).

The Public Staff presented this matter to the Commission at its Regular Staff Conference on November 1, 2010. The Public Staff stated that PEC had requested that the effective date of the Rider be changed from August 1, 2010 to January 1, 2011, and indicated that the Rider would be available until December 31, 2015. The Public Staff recommended that the Commission approve the Rider, require PEC to report the total number of RECs produced by participants under the Rider on an annual basis directly into NC-RETS, and require PEC to maintain all supporting documentation to validate participation levels, and provide such documentation for Commission and Public Staff review upon request. In addition, the Public Staff recommended that PEC's request for waiver of certain provisions of Commission Rule R8-66 with regard to the registration and reporting requirements for installation of new rooftop-mounted solar PV electric generating systems be granted as such waivers would reduce the burden of the reporting and compliance requirements pertaining to the installation of such equipment by the participants.

No other party filed comments in this proceeding.

Under the Commission's Rules and the NC-RETS Interim Operating Procedures, each person or company that registers with NC-RETS for issuance of RECs must establish each renewable energy facility as a separate "project" within NC-RETS. The NC-RETS website provides a list of all such facilities. This list helps protect the integrity of RECs issued in NC-RETS by precluding facilities from being registered in more than one registry at a time. If the owner of a facility that is being issued RECs in NC-RETS attempts to register that same facility in another tracking system, the administrator of that other tracking system can easily check the NC-RETS website to verify whether the facility is already participating in NC-RETS. PEC's request for waiver would relieve Rider participants from registering in NC-RETS, thereby thwarting the transparency needed to prevent the double-issuance of RECs. PEC should be required to address this concern by providing certain details for each Rider participant to NC-RETS.

Similarly, Commission Rules require facility owners to annually certify that the facility continues to operate as a renewable energy facility. PEC's request for waiver would relieve Rider participants from the re-certification requirement. PEC proposed to report facility production data based on an estimate rather than actual metered output. PEC should be required to verify that the facilities covered by the Rider continue to operate by performing site visits of a statistically significant number of installations.

Based on the foregoing, the Commission is of the opinion that the Rider should be approved, that the waiver from portions of Commission Rule R8-66 should be granted for participants under the Rider, but that PEC should be required to provide NC-RETS with facility information necessary to maintain transparency as discussed above. The Commission will allow PEC to report into NC-RETS the total amount of energy produced by the participants' solar facilities. PEC shall maintain and make available for review by the Public Staff and the Commission supporting documentation to validate participation levels and its estimate of electricity produced under the Rider. PEC's application form shall require participating customers to acknowledge that all RECs are the sole possession of PEC, and to certify that the RECs will not "be remarketed or otherwise resold ... for a period of not less than 5 years." In addition, PEC shall on a monthly basis provide NC-RETS with a list of participating customers, including facility location and size. NC-RETS shall post this information on its website in a manner that will facilitate its use by other registries seeking to preclude the double issuance of RECs.

IT IS, THEREFORE, ORDERED as follows:

1. That PEC's Residential Service (Experimental) SunSense Solar Rebate Rider SSR-1 is hereby approved with an effective date of January 1, 2011, available to new applicants through December 31, 2015.

2. That participants in Rider SSR-1 are exempt from the following requirements of Commission Rule R8-66:

(a) Filing a registration statement pursuant to Rule R8-66(b);

(b) Annually filing a copy of Form EIA-923 Schedules 1, 5, 6 and 9 pursuant to Rule R8-66(b)(2);

(c) Annually filing certifications of compliance with all federal and state laws, regulations, and rules for the protection of the environment and conservation of natural resources, and annually filing certification that the facility is operated as a renewable energy facility pursuant to Rule R8-66(b)(3) and (4);

(d) Annually filing a compliance statement to certify that any RECs sold to an electric power supplier will not be remarketed or resold for any purpose and annually reporting whether it sold any RECs during the prior year pursuant to Rule R8-66(b)(5); and

(e) Annually consenting to audits pursuant to Rule R8-66(b)(6).

3. That PEC, as administrator of Rider SSR-1, may forego metering each generator individually and may use the PVWatts™ Solar Calculator developed by the National Renewable

Energy Laboratory for estimating the generation from participants' solar facilities, as permitted in Commission Rule R8-67(g)(2).

4. That PEC shall report the total amount of electricity produced by facilities under the Rider directly into NC-RETS in a separately identified generation project.

5. That PEC shall maintain all supporting documentation to validate participation levels for Rider SSR-1 and shall provide it to the Commission and the Public Staff for review upon request.

6. That in years three, four and five of this Rider, PEC shall verify via site visits to a statistically significant number of participating residences that the solar installations covered by this Rider continue to be operating. PEC shall include the findings of its site visits in its annual REPS compliance report and use the findings to adjust the estimates of the electricity output of all of the Rider installations on a prospective basis. When PEC reports the results of the year-five site visits in its REPS compliance report, it shall include a recommendation as to whether such site visits should continue.

7. That PEC shall provide NC-RETS with a list of participating customers, including the location and the kW capacity of their installations, to be made available on the NC-RETS website.

8. That the participation payments and monthly bill credits paid to participants, and reasonable and prudent administrative costs associated with Rider SSR-1, shall be eligible for recovery as incremental costs pursuant to G.S. 62-133.8(h) and Rule R8-67.

9. That PEC shall file with the Commission, within 10 days following the date of this Order, a revised Rider SSR-1 showing the effective date of the tariff.

ISSUED BY ORDER OF THE COMMISSION.
This the 15th day of November, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Commissioner William T. Culpepper, III, did not participate in this decision.

kh111210.64

DOCKET NO. E-7, SUB 939
DOCKET NO. E-7, SUB 940

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 939 In the Matter of Application of Duke Energy Carolinas, LLC, For Registration of Buck Steam Station, Units 5 and 6, as New Renewable Energy Facilities DOCKET NO. E-7, SUB 940 In the Matter of Application of Duke Energy Carolinas, LLC, For Registration of Lee Steam Station, Units 1 2 and 3, as New Renewable Energy Facilities	ORDER ACCEPTING REGISTRATION OF RENEWABLE ENERGY FACILITIES

HEARD: Wednesday, July 14, 2010, at 9:30 a.m. and Thursday, July 15, 2010, at 9:00 a.m. in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

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

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BY THE COMMISSION: On March 1, 2010, Duke Energy Carolinas, LLC (Duke or Company), filed applications in the above-captioned dockets to register its Buck Steam Station Units 5 and 6 and Lee Steam Station Units 1, 2, and 3 as new renewable energy facilities, pursuant to G.S. 62-133.8 and Commission Rule R8-66, for compliance with the North Carolina Renewable Energy and Energy Efficiency Portfolio Standards (REPS), enacted through Session Law 2007-397 (Senate Bill 3).

The Commission granted petitions to intervene filed by Environmental Defense Fund (EDF) and Southern Environmental Law Center (SELC) (collectively, Environmental Intervenors); North Carolina Sustainable Energy Association (NCSEA); Progress Energy Carolinas, Inc. (PEC); GreenCo Solutions, Inc. (GreenCo); North Carolina Municipal Power Agency No. 1 and North Carolina Eastern Municipal Power Agency (collectively, Power Agencies); ElectriCities of North Carolina, Inc.; North Carolina Farm Bureau Federation (NCFB); North Carolina Forestry Association (NCFA); and MeadWestvaco Corporation (MWV). The intervention and participation of the Attorney General is recognized pursuant to G.S. 62-20; the intervention and participation of the Public Staff is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

On April 27, 2010, the Commission issued an Order consolidating these two dockets, scheduling an evidentiary hearing and oral argument, and establishing discovery guidelines.

On May 24, 2010, Duke filed the testimony of Owen A. Smith, Tracy L. Beer and Peter Stewart. On June 21, 2010, NCFB and NCFA filed the testimony of Robert W. Slocum, Jr. On June 25, 2010, EDF and SELC filed the testimony of Shawn Carraher and Carolyn Gilbert, and MWV filed the testimony of Kirby Funderburke. On July 8, 2010, MWV filed the amended direct testimony of Mr. Funderburke.

On July 8, 2010, EDF and SELC filed a motion to strike the testimony of Mr. Slocum, which motion was denied by the Presiding Commissioner at the hearing. On July 9, 2010, Duke filed the rebuttal testimony of witnesses Smith, Beer and Stewart.

The case came on for hearing as ordered on July 14, 2010. Duke presented the testimony and exhibits of witnesses Smith, Beer and Stewart, NCFB and NCFA presented the testimony of Mr. Slocum, EDF and SELC presented the testimony and exhibits of Mr. Carraher and Ms. Gilbert, and MWV presented the testimony and exhibits of Mr. Funderburke.

On September 14, 2010, Temple-Inland, Inc., and Georgia-Pacific, LLC, filed untimely petitions to intervene. On September 16, 2010, Duke filed an objection and opposition to the petitions to intervene, which petitions were denied by Order dated October 1, 2010.

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

FINDINGS OF FACT AND CONCLUSIONS OF LAW

1. Duke is a duly organized limited liability company existing under the laws of the State of North Carolina and is engaged in the business of developing, generating, transmitting, distributing, and selling electric power to the public in North Carolina, and is subject to the jurisdiction of the Commission as a public utility. Duke is lawfully before this Commission based upon its applications filed pursuant to G.S. 62-133.8 and Commission Rule R8-66 to register its Buck Steam Station (Buck) and Lee Steam Station (Lee) as new renewable energy facilities.

2. Lee is a thermal electric generating station located in Williamson, South Carolina, with a total maximum net dependable capacity (MNDC) of 370 megawatts (MW). Duke began a biomass co-firing production trial at Lee in July 2009, continuing through the end of 2009, to evaluate the use of wood as a fuel for energy production in combination with coal. This trial generated approximately 1,303 megawatt-hours (MWh) of energy attributable to the wood biomass fuel, which would result in the generation of 1,303 corresponding biomass renewable energy certificates (RECs). For the co-firing test burns, Duke blended coal with three-quarter inch sized wood chips to accommodate the requirements of the boilers at the facility.

3. Buck is a thermal electric generating station located in Salisbury, North Carolina, with a total MNDC of 369 MW. Duke conducted woody biomass co-firing test burns at Buck between August 17 and September 9, 2009. This test burn generated 2,254 MWh of energy attributable to the wood biomass fuel, which would result in the creation of 2,254 corresponding biomass RECs. At Buck, the coal was blended with both sawdust and one-half inch sized wood chips for the test burns, again to accommodate the operational specifications of the facility's boilers.

4. Duke plans to continue using Lee and Buck for evaluation of co-firing applications and as system resources utilizing wood biomass fuel in combination with coal. Duke has undertaken a comprehensive economic and operational analysis of brownfield biomass applications, with the Lee and Buck projects being part of the initial phases of a multi-phase, multi-year process. Duke intends to use a range of wood biomass fuel resources to supply its biomass operations, including wood waste materials like logging residues, sawdust and pre-commercial thinnings, and primary forest harvest materials like wood chips from whole trees.

5. Pursuant to G.S. 62-133.8(a)(7), a "renewable energy facility" means, in relevant part, a facility that generates electric power by use of a renewable energy resource. A "renewable energy resource," under G.S. 62-133.8(a)(8), means, among other things, "a biomass resource, including agricultural waste, animal waste, wood waste, spent pulping liquors, combustible residues, combustible liquids, combustible gases, energy crops, or landfill methane." The definition of "renewable energy resource" specifically excludes "peat, a fossil fuel, or nuclear energy resource."

6. "Biomass resource" is not otherwise defined in Senate Bill 3, nor is it defined in the Commission's rules interpreting Senate Bill 3. The Commission has, through the rulemaking process in Docket No. E-100, Sub 113, adopted an approach to assess whether certain proposed resources qualify as "biomass resources" on a case-by-case basis.

7. The list of resources following the words "biomass resource, including" in the definition of a "renewable energy resource" is a list of examples, not an exhaustive or exclusive list, based on the relevant case law and the specific exclusion elsewhere in the definition of other organic materials that otherwise might have been considered to be biomass resources.

8. Wood fuel derived from whole trees through primary harvests is an organic material that qualifies as a "biomass resource" and a "renewable energy resource" under G.S. 62-133.8(a)(8).

9. The registration statements for Buck and Lee meet the requirements of Commission Rule R8-66, and both facilities qualify as "renewable energy facilities" pursuant to G.S. 62-133.8(a)(7).

10. Duke may earn RECs for the renewable energy produced at Buck and Lee using renewable energy resources to meet its annual REPS obligations pursuant to G.S. 62-133.8(b)(2)(b).

<u>EVIDENCE FOR FINDING OF FACT AND CONCLUSION OF LAW NO.1</u>

This finding of fact and conclusion of law is essentially informational, jurisdictional, and procedural in nature and is not controversial.

<u>EVIDENCE FOR FINDINGS OF FACT AND CONCLUSIONS OF LAW NOS. 2 - 4</u>

The evidence supporting these findings of fact and conclusions of law appears in the registration statements for Buck and Lee and the direct and rebuttal testimony of Duke witnesses Smith and Beer.

On March 1, 2010, Duke filed registration statements for Buck and Lee seeking to register the facilities as new renewable energy facilities pursuant to Commission Rule R8-66 and to allow Duke to earn RECs associated with the renewable energy generation at the facilities to comply with its REPS obligation.

Duke witness Beer explained that Lee is a thermal electric generating station located in Williamson, South Carolina, with an MNDC of 370 MW. She stated that Duke began a biomass co-firing production trial at Lee in July 2009, continuing through the end of 2009, to evaluate the use of wood as a fuel for energy production in combination with coal. The trial at Lee generated approximately 1,303 MWh of energy attributable to the wood biomass fuel, which would result in the creation of 1,303 corresponding biomass RECs. According to Ms. Beer, for the co-firing test burns, Duke blended coal with three-quarter inch sized wood chips to accommodate the requirements of the boilers at the facility. Ms. Beer further testified that the wood fuel used for the test burns at Lee was sourced from a local external forestry services vendor who produced the material using standard in-woods chipping processes and equipment consistent with typical forestry practices. Ms. Beer stated that Duke could not characterize the wood fuel used at Lee as "wood waste" material because the chips could have contained both residual materials, as well as primary harvest material derived from whole trees.

Witness Beer further testified that Buck is a thermal electric generating station located in Salisbury, North Carolina, with a total MNDC of 369 MW. She stated that Duke conducted woody biomass co-firing test burns at Buck between August 17 and September 9, 2009, generating 2,254 MWh of energy attributable to the wood biomass fuel, which would result in the creation of 2,254 corresponding biomass RECs. At Buck, the coal was blended with both sawdust and one-half inch sized wood chips for the test burns, again to accommodate the operational specifications of the facility's boilers. Ms. Beer further testified that, for the test burns at Buck, Duke sourced the sawdust from an aggregator who obtained the material from local sawmills. The wood chips were derived from trees harvested during an on-site ash basin land clearing project, which was planned prior to, and was unrelated to, the biomass co-firing test. The fuel was chipped on-site to meet the specifications for the facility. Ms. Beer characterized the wood used for the Buck test burn as "wood waste," stating that it likely would have been burned on-site, transported to the landfill for disposal, or possibly sold into the market had it not been used for the biomass test burn.

Witness Beer explained that Duke intends to build upon the operational experience gained from the 2009 biomass runs and further develop the biomass fuel supply procurement related to short and long-term REPS compliance. She testified that Duke's biomass implementation strategy is a multi-year effort that, at full implementation and build-out, will include Duke-owned "brownfield" biomass projects expected to produce over 1 million RECs annually, and described the comprehensive economic analysis undertaken with respect to the implementation of Duke's biomass strategy. Ms. Beer testified that Buck and Lee represent the initial phase of this strategy, and explained further that the objective for the phased approach is to demonstrate proof of concept in a manner that mitigates operational and capital risk as, over time, the strategy moves from more transitory projects towards more permanent, higher capital projects. She elaborated that, through this process, Duke has evaluated the existing spectrum of biomass technologies, including gasification, as options for co-firing and/or repowering in all its coal-fired generation units as part of the first phase of its biomass co-firing assessment.

To support its biomass strategy, Duke intends to use those cost-effective wood fuels qualifying as "biomass resources" under Senate Bill 3. Also, according to Ms. Beer, Duke fully intends to utilize those lower value products, like "wood waste," first, and only move to other fuel resources to the extent those lower cost products are unavailable. Witness Beer further testified that in December 2009, Duke issued a request for information for biomass fuel supplies and received 26 responses for a variety of biomass resources. She explained that the predominant biomass fuel that was offered was derived from whole tree chips and that only one proposal was for solely "wood waste" or logging residue materials. Ms. Beer acknowledged, however, that as a matter of prudency and out of an abundance of caution given the uncertainty arising out of the proceedings in this docket, the wood fuel procured for the test burns and production runs in 2010 will all generally fall into the category of "wood waste."

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

The evidence supporting these findings of fact and conclusions of law appears in the testimony of Duke witnesses Smith, Beer and Stewart; Environmental Intervenor witnesses Carraher and Gilbert; NCFB and NCFA witness Slocum; and MWV witness Funderburke.

Pursuant to G.S. 62-133.8(a)(7), a "renewable energy facility" means, among other things, a facility that "generates electric power by use of a renewable energy resource." G.S. 62-133.8(a)(8) specifically provides that a "renewable energy resource" means:

> 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. [Emphasis added.]

Neither the statute nor the Commission's rules implementing Senate Bill 3 otherwise defines "biomass resource." As part of the rulemaking process to implement Senate Bill 3, an intervening party requested that the Commission include a more specific definition of "biomass resource" within its rules to clarify the definition of this term. The Commission declined to do so in that proceeding, seeking to avoid narrowly construing the term in a way that could limit the definition of "biomass resource," and intending to rely upon its discretion to make case-by-case determinations based on the record in individual cases. In the Commission's February 29, 2008 Order Approving Final Rules, in Docket No. E-100, Sub 113, it concluded that:

> a determination of whether a resource used by a particular facility is a "renewable energy resource," ... should be made on a case-by-case basis with an adequate opportunity for the Public Staff or other interested persons to challenge asserted facts. The registration process established in Rule R8-66 permits such a determination to be made on the basis of an appropriate record with regard to a particular facility.... Therefore, rather than potentially limit the definition of "biomass" on the basis of an incomplete record in this rulemaking proceeding, the

Commission concludes that the statutory definition of "renewable energy resource" is sufficient and that "biomass" should not be separately defined in Rule R8-67.

Duke argues that the Commission, guided by case law, must apply rules of statutory construction to interpret the term "biomass resource" consistent with the intent of the General Assembly and then apply that interpretation to the facts and circumstances of this particular case. Under North Carolina law, notes Duke, the cardinal principle of the canons of statutory construction is to ensure accomplishment of the legislative intent of the subject statute. See L. C. Williams Oil Co. v. NAFCO Capital Corp., 130 N.C. App. 286, 289, (1998). To that end, one must consider "the language of the statute ..., the spirit of the act and what the act seeks to accomplish:" Coastal Ready-Mix Concrete Co. v. Board of Comm'rs, 299 N.C. 620, 629 (1980). Undefined words are accorded their plain meaning so long as it is reasonable to do so, see Woodson v. Rowland, 329 N.C. 330, 338 (1991), and the reviewing body must evaluate the statute as a whole and must not construe an individual section in a manner that renders another provision of the same statute meaningless. See Williams v. Holsclaw, 128 N.C. App. 205, 212, aff'd, 349 N.C. 225 (1998).

In G.S. 62-133.8(a)(8), the General Assembly chose to add a list of qualifying resources, preceded by the word "including," after the reference to "biomass resource" in the definition of "renewable energy resource." In its brief, Duke argues that, based upon generally accepted norms of statutory construction, where a list is preceded by the word "includes," which is generally a term of enlargement rather than limitation, N.C. Turnpike Authority v. Pine Island, Inc., 265 N.C. 109, 120 (1965) (quoting People v. Western Air Lines, Inc., 42 Cal. 2d 621, 639, 268 P.2d 723, appeal dismissed sub nom. Western Airlines, Inc. v. California, 348 U.S. 859, 75 S.Ct. 87, 99 L.Ed. 677 (1954)), it indicates that matters other than those enumerated can be a part of the subject group. See Norman J. Singer, 2A Sutherland on Statutory Construction 231-232 (2000). Moreover, Duke asserts that, according to A Dictionary of Modern Legal Usage, "including should not be used to introduce an exhaustive list, for it implies that the list is only partial." Duke similarly cites Merriam-Webster Dictionary, which defines the term "including" as meaning "to take in or comprise as part of a whole or group." Thus, to "include" one thing does not implicitly "exclude" another due to the plain fact that "including" one or more items in the specified whole or group simply means, pursuant to this definition, that those specified items are merely part of that whole or group. As such, according to Duke, adding "but not limited to" or "without limitation" after "including" does not change the meaning of term. Duke further states that, as stated in Sutherland on Statutory Construction, "it is hornbook law that the use of the word 'including' indicates that the specified list ... that follows is illustrative, not exclusive." Certified Color Mfg. Ass'n v. Mathews, 543 F.2d 284, 296 (D.C.Cir. 1976).

Duke further argues that the North Carolina Supreme Court adopted this rule of statutory construction in Turnpike Authority, quoting the West Virginia Supreme Court's analysis on the construction of the term "including":

> Clearly, by use of the word 'including' the lawmakers intended merely to list examples ..., but not to exclude others equally well known. Had the latter been their intention, the proper expression to have been used would have been 'comprising,' 'consisting of,' or some synonymous term. This is not a situation

which calls for the application of the maxim, 'expressio unius est exclusio alterius.'

See also Polaroid Corp. v. Offerman, 349 N.C. 290, 301 (1998) ("includes" indicates the General Assembly's intention to enlarge, not limit, a statutory definition). Duke argues that the Commission has adopted this interpretation of "including" in the context of the definition of "biomass resource", as it specifically noted in the February 24, 2010 Order on Request for Declaratory Ruling, in Docket No. SP-100, Sub 25, that "the definition of 'renewable energy resource' in G.S. 62-133.8(a)(8) includes 'biomass resource,' listing several examples without limitation." (Emphasis added.)

Duke specifically asserts that "biomass", as defined by the federal Biomass Research and Development Technical Advisory Committee,[1] means "any organic matter that is available on a renewable or recurring basis, including agricultural crops and trees, wood and wood wastes and residues, plants (including aquatic plants), grasses, residues, fibers, animal wastes, and segregated municipal waste ...." (Emphasis added.) Duke notes that the North Carolina Biomass Council, the North Carolina State Energy Office, and the North Carolina Solar Center have adopted and incorporated this definition into the North Carolina Biomass Roadmap. Duke points out that the Commission has also used this definition in its evaluation of requests for declaratory rulings and decisions to approve registration statements for facilities using "biomass" fuels that were not included in the explicit statutory list within G.S. 62-133.8(a)(8). For example, the Commission has ruled that biosolids[2] (the organic material remaining after treatment of domestic sewage), refuse-derived fuel,[3] and tire-derived fuel[4] (to the extent of the naturally occurring rubber) are all "renewable energy resources" and eligible to earn RECs for REPS purposes. Duke argues that wood, in its various forms and iterations through its life-cycle, is undoubtedly "biomass" under this generally accepted definition of the term. If one reduces the definition to its component elements, then it is apparent that wood qualifies as a "biomass resource." First, wood is organic plant material; second, wood is available on a renewable and recurring basis in the forests of this State and country. Thus, according to Duke, to effectuate the intent of the General Assembly that "biomass resources" qualify as "renewable energy resources" for REPS compliance purposes, wood must be considered a "renewable energy resource" under the law. Duke contends that there is no dispute as to whether wood constitutes an organic plant material, but there remains a dispute as to whether it is available on a renewable and recurring basis. It further contends that trees, as plant material, are inherently renewable and recurring. Duke emphasized that trees will regrow through natural germination processes in the absence of affirmative replanting or other cultivation intervention.

[1] The Biomass Research and Development Technical Advisory Committee is a multi-agency federal initiative supported by the U.S. Department of Agriculture and U.S. Department of Energy to coordinate and accelerate Federal biobased products and bioenergy research and development.

[2] Order on Request for Declaratory Ruling, Docket No. SP-100, Sub 25 (February 24, 2010).

[3] Order on Request for Declaratory Ruling, Docket No. SP-100, Sub 23 (March 25, 2009).

[4] Order Issuing Amended Certificates, Accepting Registration Statement and Issuing Declaratory Ruling, Docket No. SP-165, Sub 3 (December 17, 2009).

Duke further argues that a limiting interpretation of "biomass resource" will result in practical impacts that contravene the basic purposes of Senate Bill 3. Witness Smith testified that wood-fired biomass represents the renewable resource with the most readily achievable, scalable development potential within North Carolina, but that potential would be marginalized if Duke could only use "wood waste" as fuel due to the lack of adequate supply of such fuel in the marketplace to meet its needs. Specifically, both witnesses Smith and Beer stated that, if only "wood waste" qualifies as a "biomass resource," Duke will not likely pursue its biomass strategy to full implementation.

Duke witness Stewart, with Forest2Market, Inc., defines "wood waste" as limbs, tops, harvest slash and residues, pre-commercial thinnings and other byproducts or residual wood resulting from forest management activities, otherwise known as "forest residues." Mr. Stewart testified that, due to the lack of a market for the product, only 6% of in-woods forest residues are currently collected within Duke's potential procurement area, defined as Duke's service territory and those areas outside the service territory that are within an economic haul distance to its generating facilities. Based on data from Forest2Market's transactional database that tracks approximately 80% of all timber transactions in the southern United States, only 2% of the total harvest in North Carolina, or approximately 305,918 tons, came from forest residue materials in 2009. Projecting forward, Mr. Stewart estimated that Duke could expect approximately 275,000 tons of "wood waste" or forest residue material annually. Mr. Stewart testified that this amount of fuel will not support Duke's fuel needs for its planned co-firing and repowering generation projects. Witness Stewart's testimony was consistent with witness Beer's statement that, based on this fuel supply assessment, if Duke was limited to using "wood waste" materials, the projected annual REC production from its biomass operations would drop from over 1 million RECs to approximately 220,000 RECs.

Witness Stewart also testified that the eligibility of all harvested wood as a "biomass resource" under Senate Bill 3 should not result in direct competition between bioenergy facilities and the softwood lumber and plywood industries due to the simple issue of cost. Mr. Stewart acknowledged that the pulpwood market would experience some competition between energy companies and pulp and paper companies as a result of increased demand, but also stated that, given the restrictions of the cost caps, Duke would likely not have the appetite for higher cost wood products.

Duke witness Smith testified that a limitation on eligible wood biomass fuel to only "wood waste" would impact the cost of the qualifying fuel resources, thereby reducing the cost-effectiveness of wood-fired biomass, limiting the potential for large-scale development, and requiring the consideration of less cost-competitive resources. Due to the practical realities of the development path of renewable resources to date within North Carolina, Mr. Smith detailed that alternative options are limited. Witness Smith explained that, at present, landfill gas represents the most cost effective, in-state REPS-eligible resource available in the marketplace; however, there are only so many landfills, and, therefore, the potential for development of that resource is effectively capped. He elaborated that wind resource development in North Carolina is inherently limited by the natural wind conditions of the State as well as by specific legal, operational, and cost constraints in the mountains and on the coast. Finally, although solar generation exists as a scalable renewable resource option, Mr. Smith stated that it is simply not cost-competitive with wood biomass and would likely be constrained by a lack of availability of suitable land that would be needed to support the farms and arrays necessary to attempt to match the capacity and output of a handful of biomass generation facilities.

By considering less cost-competitive resources out of necessity, witness Smith stated that Duke's incremental REPS costs of compliance would increase, likely significantly, because there is not a ready substitute for wood-fired biomass in terms of actual megawatt-hour energy output due to its baseload comparable capacity factors. Witness Smith explained that, as incremental costs of compliance increase, the number of RECs Duke can procure for compliance under the statutory cost caps are reduced. Mr. Smith noted that, although the cost caps may provide an off-ramp for REPS compliance purposes, the invocation of the cost cap off-ramp for REPS does not in any way reduce overall system-wide demand for energy. As such, for every megawatt-hour of renewable energy that is not procured for REPS compliance due to the invocation of the cost caps, Duke must generate or procure a corresponding megawatt-hour of non-incremental, likely non-renewable, energy from its other system resources to meet demand. In this way, the elimination of a large-scale, cost-effective renewable option, like wood biomass, will only lead to continued use of fossil generation by Duke to provide energy that could otherwise be delivered from a renewable resource.

Duke witness Beer also testified that to assure sustainability in fuel supply, such that the wood biomass fuel would be available on a renewable and recurring basis, Duke has specifically sized (in terms of capacity) its proposed biomass projects and specifically modeled its fuel supply requirements for those proposed projects based upon specific parameters. In the context of the evaluation of a potential repowering project as part of its biomass implementation strategy, Ms. Beer explained that Duke commissioned a fuel supply forecast for the life of the repowered asset, which applied specific constraints related to the volume of material and associated pricing that could be sustainably supplied while maintaining 2008 harvest levels of existing users and without impacting the economic viability of any existing user of forest resources within the relevant supply shed. Witness Beer testified that Duke's intentional constraints on its fuel supply forecast in this manner provided an explicit sustainability function from both an economic and environmental perspective as both existing uses and previous harvest levels acted as clear limits on fuel supply procurement for the project.

Ms. Beer stated that as an end-user of forest resources in North Carolina, Duke will also support the sustainability of forest resources by paying the assessment on primary forest products that is remitted to the State for inclusion in the North Carolina Forest Development Program (FDP), as required by the Forest Development Act and the Primary Forest Product Assessment Act. As referenced by NCFB and NCFA witness Slocum, the FDP is a reforestation cost-sharing program through which a landowner is reimbursed for a portion of the costs of site preparation, seedling purchases, tree planting, release of desirable seedlings from competing vegetation, or any other work needed to establish a new forest on his or her land after harvesting.

Ms. Beer also reiterated that when Duke issued its request for information for biomass fuels supply in December 2009, respondents were asked to provide detailed descriptions of industry certifications, best management practices, and sustainability plans related to their fuel sourcing. She emphasized that the specifications regarding annual delivery requirements of 100,000 tons also sent a specific market signal to loggers, foresters, and landowners that a continuous, recurring demand for woody biomass fuel is present within the area, which was intended to incentivize sustainable practices on the part of the suppliers to ensure that they can actually compete to meet that demand on an ongoing basis.

Duke witness Smith also emphasized that the manner in which Duke has chosen project sites and project sizes has been guided carefully by the Company's conservative assessment of the quantity and nature of biomass fuels that can be procured in a sustainable manner over a long planning horizon within proximity to the sites in question. Mr. Smith further stated that the interests of Duke and its customers would not be served by investing in co-firing or repowering projects in locations where the procurement of biomass fuel could not be done in a reliable, sustainable, and cost effective manner. However, Duke has not self-regulated in this regard and placed specific sustainability requirements on its vendors because in the absence of statutory or regulatory requirements mandating such provisions, any incremental costs in the price of fuel due to such self-regulation may not be considered prudent under the circumstances. Mr. Smith testified that Duke believes that the careful evaluation of project locations and sizes is completely responsive to any questions of sustainability that may exist, and furthermore believes that such diligence is expected by the Commission in its normal expectations of prudent and reasonable decision-making on the part of a utility such as Duke.

In their brief, the Environmental Intervenors contend that, based on a plain reading of Senate Bill 3, the only renewable woody biomass resources that are intended to be "renewable energy resources" are "wood waste" materials. They assert that, by choosing to list the term "wood waste" following the general definition instead of "wood" or "wood chips" or "whole trees," the General Assembly specifically limited the type of wood that constitutes a "biomass resource" and a "renewable energy resource" under Senate Bill 3.

The Environmental Intervenors further argue that the legislative history of Senate Bill 3 supports their interpretation that "biomass resource" was intended to include only "wood waste" as an eligible wood product. They included as exhibits to their brief prior draft legislation from the 2005 legislative session: a letter dated February 23, 2006, from George Givens, Commission Counsel to the Environmental Review Commission, to Jo Anne Sanford, Chair of the Commission; the Agenda for the January 24, 2006 Meeting of the Environmental Review Commission; the Request for Proposals for Consulting Services on a Renewable Energy Portfolio Standards, dated May 12, 2006; the Minutes from the December 13, 2006, Meeting of the Environmental Review Commission; and an e-mail from George Givens, dated February 14, 2007, to a list of stakeholder participants for a meeting of the Energy Issues Working Group. The Environmental Intervenors argue that these documents provide evidence of the specific legislative intent to exclude all wood resources, other than "wood waste," from the definition of "biomass resources" under Senate Bill 3.

The Environmental Intervenors further cite the resource definition for eligible woody biomass within the voluntary NC GreenPower program, which was adopted for use in the LaCapra Study. They argue that this definition does not include any wood resources other than "wood waste," and that, since the limited scope of eligible woody biomass under the NC GreenPower voluntary program and the LaCapra Study was squarely before the legislature at the time that Senate Bill 3 was passed, only those materials eligible for such program could possibly have been considered by the General Assembly. The Environmental Intervenors conclude that Senate Bill 3 involved a collaborative process and revisions were made to the legislation to add certain resources to the illustrative list after "biomass resources." Thus, the fact that the ultimate session law only lists "wood waste" after "biomass resource" is dispositive with respect to the General Assembly's intent with respect to qualifying wood resources.

Environmental Intervenor witnesses Carraher and Gilbert testified that Duke witness Stewart's assessment of actual potential fuel supply from "wood waste" is overly conservative and that the practical impact of using only "wood waste" as fuel is overstated. They stated that Mr. Stewart's estimates for annual fuel supply from forest residues are approximately 80% lower than the next closest estimate from the independent studies that they reviewed and that he artificially constrained the procurement area for his analysis by limiting the analysis to Duke's service territory and the area within an economic haul distance from its facilities. Lastly, witnesses Carraher and Gilbert assert that Duke has failed to provide an economic analysis and comparison of the costs to use whole trees as fuel versus the costs of "wood waste" materials at Buck and Lee, and that the registration statements should be denied until that analysis is performed.

In its pre-hearing brief, MWV took a position identical to that of the Environmental Intervenors, that "biomass resource" should be limited to the list explicitly provided in the statute. MWV witness Funderburke asserted that Duke's interpretation of "biomass resource" to include wood products other than "wood waste" directly contradicts other State and federal laws regarding renewable resources. Mr. Funderburke stated that using wood products other than "wood waste" is not in the public interest because of the negative impacts on traditional wood-using industries arising from the additional demand. He further argued that using wood for bioenergy applications is not the best use for merchantable wood in North Carolina, and such use will eliminate value from the wood supply chain, thereby damaging wood-using industries and the local economy. Mr. Funderburke also stated that Duke is not truly constrained by the cost caps when it comes to biomass fuel procurement, as Duke may recover a portion of its fuel costs through its fuel adjustment clause, thereby giving it extra headroom to pay higher prices for wood and outspend existing wood-using competitors.

In its post-hearing brief, MWV argued that the Commission should adopt the following definition of "wood waste":

> Wood waste is a woody material that does not currently have an existing market. It is the lowest wood resource in the value chain of wood. An existing market means there is a user currently willing to purchase the material including the cost of harvesting and transporting the material to a user's facility. Wood waste would generally include precommercial thinnings (including stands in areas with no markets for small diameter wood), logging debris from commercial harvests (limbs, tops, bark), very small diameter trees (less than 4 inches diameter breast height (DBH)) and other non-merchantable trees in clearcuts, and municipal woody organic waste material such as construction debris.

This definition includes whole trees for which there is no market, including "stands in areas with no markets for small diameter wood" and trees "less than 4 inches diameter breast height." MWV argues that it would not be inconsistent or otherwise inappropriate for the Commission to approve Duke's registration applications by modifying its use of "whole tree chips" to those trees which fall within the above definition of "wood waste."

In its brief, NCSEA agrees with the Environmental Intervenors that "renewable energy resource" does not include whole trees or wood derived from whole trees. NCSEA argues, however, "that whole trees or wood chips from whole trees can be a qualifying biomass and a renewable energy resource where the material is a secondary material or a primary material cultivated or collected for the purpose of energy recovery using sustainable practices." (Emphasis in original.) NCSEA, in analyzing the statute, argues that

> the definition of renewable energy resource shows that a biomass qualifies as a "renewable energy resource" when beyond being biomass, it is a secondary material (e.g., "agricultural waste, animal waste, wood waste, spent pulping liquor, combustible residues"), or primary material (the direct, intended output of an activity) cultivated, grown or collected specifically for energy recovery, e.g., combustible liquids, combustible gases, energy crops or landfill methane.

Thus, NCSEA would allow Duke to earn RECs from its use of whole trees at Buck, but argues that insufficient information is available for the material used at Lee.

The Public Staff, NCFB and NCFA contend, in agreement with Duke and PEC, that wood other than "wood waste" qualifies as "biomass" based on the plain meaning of the definition of "biomass" itself. In their pre-hearing brief, NCFB and NCFA state that the Merriam Webster Online Dictionary (2010) defines "biomass" simply as "plant material or animal waste used especially as a source of fuel." Public Staff cites a separate definition from the American Heritage College Dictionary (3rd ed. 1997) where "biomass" is defined as "plant material, vegetation or animal waste used as an energy source." Public Staff also cites the definition from the North Carolina Biomass Roadmap, and asserts that under either definition, all sources of wood material cannot reasonably be defined as anything other than "biomass." In its letter filed after the hearing, the Public Staff states that it supports Duke's position that all forms of wood constitute "biomass" within the meaning of G.S. 62-133.8(a)(8), and argues that the Commission should accept the registration of Duke's Buck and Lee units as renewable energy facilities.

NCFB and NCFA witness Slocum, a licensed forester, agreed with Duke's assertion that trees will naturally regrow, and testified that a harvested forest stand will regenerate naturally without any intervention unless the stand is paved over. Mr. Slocum further testified that the best avenue through which to keep North Carolina land in forestry is to provide robust, healthy markets for wood products, and that new demand for wood products relating to bioenergy fuel supply provides an additional market for wood products. Mr. Slocum also explained that specific State and federal cost share and tax benefit programs exist to support forest development, including the North Carolina FDP, the federal Present Use Value Tax Program, and certain provisions of the Farm Bill. Witness Slocum also stated that timber harvesting is regulated through various federal environmental protection laws, primarily relating to water quality and related impacts. Mr. Slocum also testified that current conditions indicate that timber products are being sustainably managed as the total acreage in forestland, net timber growth per acre, and timber inventories for hardwood and softwood increased in North Carolina between 2002 and

2007, thus supporting the conclusion that productive forestland in North Carolina is actually increasing.

After careful consideration, the Commission agrees with Duke, the Public Staff and others and finds and concludes that primary harvest wood products, including wood chips from whole trees, are "biomass resources" and "renewable energy resources" under G.S. 62-133.8(a)(8). The language of the statute demonstrates that the General Assembly did not intend to limit the scope of biomass resources qualifying as renewable energy resources to those resources specifically listed within the statute. "Biomass" is a broad category of resources and one that this Commission recognizes could be the source for a significant portion of the energy and RECs that the electric power suppliers use to comply with the REPS requirements.

The intent of the General Assembly further appears clear from a review of the definition of "renewable energy resource" as a whole. In the last sentence of the definition, the General Assembly explicitly provided that peat, a form of biomass, was excluded from the definition of "renewable energy resource." This explicit exclusion would have been unnecessary had the General Assembly intended to limit the definition of "biomass resource" to the items listed after the word "including" because peat is not either "agricultural waste, animal waste, wood waste, spent pulping liquors, combustible residues, combustible liquids, combustible gases, energy crops, or landfill methane." Thus, reading the statute as a whole, it is reasonable to conclude that the General Assembly did not intend to limit the development of "biomass resources" only to those listed in the definition of "renewable energy resource."

Moreover, the legislative history documents referenced by the Environmental Intervenors do not reflect a decision to affirmatively include only "wood waste" in the definition of "biomass resource" or to exclude all other wood resources from that definition. The Environmental Intervenors' position regarding the legislative history relies upon inference and ignores the clear language of the statute, primarily the use of the word "including" in advance of the list that follows the term "biomass resource." With respect to the Environmental Intervenors' references to the eligibility definitions in the NC GreenPower program and within the LaCapra Study, there is no reference within Senate Bill 3 to that definition, nor any specific indication within the law that those definitions were of any particular import to the General Assembly's ultimate decisions with respect to the resources that would qualify as either "renewable energy resources" or, more specifically, "biomass resources". To the extent that those definitions were even specifically considered by the General Assembly, they were not adopted as part of Senate Bill 3, and the applicability of any limitations within the NC GreenPower or LaCapra Study resource definitions cannot be imputed to the intent of the General Assembly.

Additionally, the Commission is encouraged by the steps Duke has taken to ensure that its fuel procurement will be accomplished in an economically and environmentally sustainable manner, such that the fuel that it procures will be available on "renewable and recurring" basis. Duke witnesses testified that it has strategically sized its operations to reduce impacts on existing users of wood products within its procurement area, sent explicit demand signals to vendors regarding its required annual demand and acceptable practices and explored strategic opportunities to invest in energy crops and trees to provide portions of the fuel supply necessary to run its operations. Taken collectively, Duke's actions appear to represent a reasonable plan to ensure sustainable fuel supplies for its planned facilities and to mitigate any impacts on existing users within its procurement area. Further, the Commission encourages Duke to continue to maintain and adhere to reasonable, sustainable plans and practices as they relate to the procurement of wood products for fuel supply.

EVIDENCE FOR FINDINGS OF FACT AND CONCLUSIONS OF LAW NOS. 9 - 10

The evidence supporting these findings of fact and conclusions of law appears in the registration statements for Buck and Lee and the testimony of Duke witness Beer.

"Renewable energy facility" is defined, 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." "New renewable energy facility" is defined, in relevant part, as "a renewable energy facility that ... [w]as placed into service on or after January 1, 2007." Duke requested that Buck and Lee be registered as new renewable energy facilities.

The Commission notes that it is not necessary for Buck and Lee to be registered as renewable energy facilities or as new renewable energy facilities in order for Duke to apply the energy produced by co-firing toward meeting its REPS requirements. Duke may meet its REPS requirements by 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." G.S. 62-133.8(b)(2)(b). Nevertheless, these facilities meet the definition of renewable energy facility. Neither facility, however, 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.

Furthermore, in its June 17, 2009 Order on Motion for Clarification in Docket No. E-100, Sub 113, the Commission concluded that, with regard to small hydroelectric generating units, "individual generating units that are components of a larger hydroelectric generating plant are not individual renewable energy facilities." Rather, the term "facility" refers to the entire generating plant. Similarly, here, no evidence has been provided that the individual units at Buck and Lee should be individually registered as renewable energy facilities rather than the entire Buck and Lee Steam Stations. In its proposed order, Duke refers to Buck and Lee as two facilities consistent with this conclusion.

On March 8, 2010, and March 12, 2010, respectively, the Public Staff filed the recommendations required by Rule R8-66(e) stating that Duke's registration statements for Buck and Lee should be considered to be complete.

Therefore, having concluded that wood biomass qualifies as a "biomass resource", and thus a "renewable energy resource", under G.S. 62-133.8(a)(8), the Commission concludes further that Lee and Buck qualify as, and should be registered as, "renewable energy facilities" pursuant to G.S. 62-133.8(a)(7) and Commission Rule R8-66. Finally, the Commission concludes that Duke may earn RECs for the renewable energy produced at Buck and Lee using renewable energy resources to meet its annual REPS obligations pursuant to G.S. 62-133.8(b)(2)(b).

IT IS, THEREFORE, ORDERED as follows:

1. That the registration by Duke for Buck and Lee as renewable energy facilities shall be, and hereby is, accepted; and

2. That Duke shall annually file the information required by Commission Rule R8-66 for Buck and Lee by April 1 of each year.

ISSUED BY ORDER OF THE COMMISSION.
This the 11th day of October, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Commissioner William T. Culpepper, III, dissents, in part.

Sw101110.02

DOCKET NO. E-7, SUB 939
DOCKET NO. E-7, SUB 940

Commissioner William T. Culpepper, III, dissenting in part:

I respectfully dissent from that portion of this Order Accepting Registration of Renewable Energy Facilities that finds and concludes that primary harvest wood products, including wood chips from whole trees, are "biomass resources" and "renewable energy resources" under G.S. 62-133.8(a)(8).

The issue of whether or not the use of whole trees harvested for the purpose of electricity generation is allowable for renewable energy portfolio standard compliance purposes has been "on the table" ever since the enactment of Senate Bill 3.

In its March 2010 Report and Recommendations Concerning Forest Resource Impacts of the Woody Biomass Industry in North Carolina (March 2010 Report), the North Carolina Environmental Management Commission (EMC) stated its finding that "[t]he differing interpretations of the statutory definition of 'renewable energy resource' as applicable to 'biomass' result in uncertainty and confusion as to the types of biomass resources eligible under the Renewable Energy Portfolio Standard ...", and concluded that "[t]he General Assembly should clarify the definition of 'renewable energy resource' in relation to woody biomass."[1]

On page 10 of the March 2010 Report, the EMC writes:

> As written the definition of renewable energy resource allows for a range of interpretations as to what the legislature intended to include as a biomass resource. ...
>
> One view of this definition is that it is intended to encompass all woody biomass resources and is not restricted to wood waste. The acceptance of this interpretation in its most basic form would allow the use of any type of woody biomass resource to meet the mandates of Senate Bill 3, including the harvesting and burning of whole trees. ...
>
> Another view of the definition is that it is intended to be narrowly read and restricts biomass resources to wood waste. Supporters of this position contend that the listing of biomass sources in the definition is done for limiting purposes, rather than illustrative purposes. ...
>
> A recent ruling by the Utilities Commission in a request for Declaratory Ruling by the Water and Sewer Authority of Cabarrus County found that biosolids (the organic material remaining after the treatment of domestic sewage) is a renewable energy resource for combustion purposes. ... The Utilities Commission in the order writes, "G.S. 62-133.8(a)(8) includes any biomass resource, listing several examples without limitation."[2] The Commission's order indicates that it will interpret the definition of biomass resource very broadly.[3]

The North Carolina Biomass Council has developed a roadmap[4] at the request of the North Carolina State Energy Office as a tool to assist stakeholders in planning North Carolina's future biomass utilization. This roadmap defines biomass as "any organic matter that is available on a renewable or recurring basis, including agricultural crops and trees, wood and wood wastes and residues, plants (including aquatic plants), grasses, residues, fibers, animal wastes, and

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[1] March 2010 Report, page 3.

[2] This dictum was unnecessary with respect to the Commission's narrow holding in Docket No. SP-100, Sub 25, i.e. that biosolids are included as a biomass resource for Senate Bill 3 purposes. Insofar as this dictum should be interpreted to say that "biomass resource" in G.S. 62-133.8(a)(8) includes all biomass without any limitation, it is not a correct statement of the law as I believe it to be.

[3] Thus, interestingly, the EMC correctly predicted the majority's decision in this docket.

[4] The North Carolina **Biomass Roadmap**: Recommendations for Fossil Fuel Displacement through Biomass Utilization, May 2007.

segregated municipal waste ... Processing and conversion derivatives of organic matter are also biomass."

In its definition of "renewable energy resource", the General Assembly did not utilize the foregoing definition of biomass or simply use the term "biomass."[1] Instead, the legislature opted to utilize the phrase "a biomass resource, including agricultural waste, animal waste, wood waste, spent pulping liquors, combustible residues, combustible gases, energy crops or landfill methane."

I am of the opinion that use of the foregoing phraseology indicates 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 statue and others not named that are *ejusdem generis*.[2] [3]

As applicable to this matter, the rule of statutory *ejusdem generis* provides that where general words (e.g. agricultural waste, animal waste, wood waste, etc.) follow a particular subject (i.e. biomass resource), the meaning of the general words will ordinarily be presumed to be, and construed as, restricted by the particular designations and as including only things of the same kind, character and nature as those specifically enumerated. See Knight v. Town of Knightdale, 164 N.C.App. 766, 769, 770 (2004). As noted by the North Carolina Sustainable Energy Association (NCSEA), in Senate Bill 3 a biomass qualifies as a renewable energy resource when, beyond being biomass, it is generally either a secondary material (e.g. "agricultural waste, animal waste, wood waste, spent pulping liquors, combustible residues") or primary material cultivated or collected specifically for energy production (e.g. energy crops, landfill gas).[4] Wood chips derived from the harvesting of mature growth whole trees does not fit fit into either of these categories, nor is it of the same kind, character and nature of the forms of biomass specifically enumerated in G.S. 62-133.8(a)(8).

Had the legislature intended the term "biomass resource" in Senate Bill 3 to include whole trees, it would have been more than easy enough for it to have done so by using the term "trees, wood and wood waste" or "wood and wood waste" (or even simply "wood" without any limitation) – or, as previously noted, by simply utilizing the term "biomass" without any other words of limitation, in lieu of the term "wood waste." Put another way, I believe that had the North Carolina legislature intended to include the primary harvest of whole trees as a Senate Bill 3 biomass resource, it would have done so in no uncertain terms.[5]

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[1] That is to say, the legislature could have defined renewable energy resource as "a solar electric, solar thermal, wind, hydropower, geothermal, biomass, or ocean current or wave energy resource ...", but it chose not do so.

[2] **EJUSDEM GENERIS**. Of the same kind, class, or nature. Black's Law Dictionary, 4th Ed.Rev.

[3] e.g. Refuse-derived fuel segregated from municipal solid waste (NCUC Docket No. SP-100, Sub 23); Biosolids (organic material remaining after treatment of domestic sewage)(NCUC Docket No. SP-100, Sub 25); and Natural rubber component of tire-derived fuel (NCUC Docket No. SP-165, Sub 3).

[4] NCSEA's Post-Hearing Brief, page 6.

[5] For example, see Michigan 2008 PA 295, Sec. 3(f) which reads, in pertinent part:

Furthermore, in light of the importance of the forestry industry to the State of North Carolina, a well-known fact recognized by the General Assembly,[1] I am unable to accept the idea of the state legislature enacting law that permits the clear cutting of old growth forest land for electricity generation purposes without providing concomitant requirements of best forestry practices and/or other sustainability measures.[2]

\s\ William T. Culpepper, III
Commissioner William T. Culpepper, III

"Biomass" means any organic material that is not derived from fossil fuels, ... including, but is not limited to, all of the following:

...

(iv) Trees and wood, but only if derived from sustainably managed forests or procurement systems, as defined in Section 261c of the management and budget act ... .

...

(vi) Precommercial wood thinning waste, brush, or yard waste.

(vii) Wood wastes and residues from the processing of wood products or paper.

1 See G.S. Chapter 113A, Article II, *Forest Development Act* where G.S. 133A-177(a) reads, in pertinent part:

The General Assembly finds that:

(1) It is in the public interest of the State to encourage the development of the State's forest resources and the protection and improvement of the forest environment.

...

(3) Regeneration of potentially productive forest land is a high-priority problem requiring prompt attention and action. ...

2 As noted on page 12 of this Order, Duke does not intend to place any sustainability requirements on its whole tree vendors, since there are no statutory or regulatory provisions mandating such requirements.

DOCKET NO. E-22, SUB 418

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter Application of Virginia Electric and Power) Company, d/b/a Dominion North Carolina) Power, for Authority to Transfer Functional) Control of Transmission Assets to PJM) Interconnection, LLC)	ORDER OPTING OUT OF RETAIL CUSTOMER PARTICIPATION IN WHOLESALE DEMAND RESPONSE PROGRAMS

BY THE COMMISSION: By Order issued on April 19, 2005, the Commission allowed Virginia Electric and Power Company, doing business in North Carolina as Dominion North Carolina Power (Dominion), to join PJM Interconnection, LLC (PJM), subject to a number of conditions. In this Order, the Commission found that North Carolina has elected to retain a traditional electric industry structure and to require utilities to furnish electric service on an integrated, least-cost basis at just and reasonable cost-based rates pursuant to a comprehensive regulatory structure. The conditions were imposed for the purpose of protecting Dominion's North Carolina retail ratepayers from adverse impacts as a result of Dominion's integration into PJM and to preserve the Commission's existing authority to set the rates, terms and conditions of retail electric service to Dominion's North Carolina retail customers.

On October 17, 2008, the Federal Energy Regulatory Commission (FERC) issued its Order No. 719 approving a Final Rule in Docket No. RM07-19-000 for the purpose of establishing reforms to improve the operation of organized wholesale electric power markets, including, among other things, removing barriers to the comparable treatment of electric power supply and demand response, or voluntary load reduction by retail customers. This Order required Regional Transmission Organizations (RTO) and Independent System Operators (ISO) to amend their market rules, as necessary, to permit an aggregator to bid demand response on behalf of retail customers directly into the RTO's or ISO's organized markets unless the laws or regulations of the relevant electric retail regulatory authority did not allow retail customers to participate. The FERC determined that allowing an aggregator to act as an intermediary for many small retail loads that cannot individually participate in the organized market would reduce a barrier to demand response. A large retail customer that has the ability to reduce load by a minimum of 100 kW is allowed to participate individually through a third party without being aggregated with other loads.

In response to numerous requests for rehearing and clarification, on July 16, 2009, the FERC issued Order No. 719-A, which became effective on August 28, 2009. In this Order, the FERC made clear that it was not challenging the role of states and others to decide the eligibility of retail customers to participate in demand response programs, including the imposition of conditions upon any such participation. The FERC further stated that it was leaving it to the appropriate state or local authorities to set and enforce their own requirements, emphasizing that the decision, policy, or condition should be clear and explicit so that the RTO or ISO is not tasked with interpreting ambiguities. On December 17, 2009, the FERC issued its Order No.

719-B affirming its basic determinations in Order Nos. 719 and 719-A, granting limited clarification, and denying rehearing.

The Final Rule resulting from these Orders prohibits RTOs and ISOs from accepting bids from aggregators that wish to register retail customers for participation in demand response programs that are customers of utilities that distributed more than four million MWh in the previous fiscal year, where the relevant electric retail regulatory authority prohibits such customers' demand response to be bid into organized markets by an aggregator. The Rule also recognizes the authority of the relevant electric retail regulatory authority to impose conditions upon the participation of retail customers in such programs. As implemented, retail regulatory authorities with jurisdiction over larger utilities have to take affirmative action to "opt out" or eligible retail customers can automatically.participate.[1]

While the first rehearing was pending, PJM filed, in FERC Docket No. ER09-701-000 and ER09-701-001, proposed revisions to its Amended and Restated Operating Agreement of PJM and the PJM Open Access Transmission Tariff to clarify the effect of state regulatory actions regarding retail customer authorization to participate in PJM's demand response programs. By Order dated September 14, 2009, the FERC conditionally accepted the proposed tariff revisions, but required an additional compliance filing. PJM made this filing on November 20, 2009, in Docket No. ER09-701-003. Approval by the FERC of this filing is still pending.

PJM has several different demand response program categories, but, generally speaking, for larger utilities the procedure under PJM's revised compliance filing is as follows: (1) the entity wishing to register retail customers for participation in the PJM program completes the registration form located on PJM's website; (2) after confirming that all of the qualifications to be a participant in the relevant program have been met, PJM notifies the appropriate electric distribution company or load serving entity of the registration and requests verification as to whether the load is subject to another contractual obligation or to laws or regulations of the Relevant Electric Retail Regulatory Authority that prohibit or condition an end-use customer's participation in PJM's program; and (3) the electric distribution company or load serving entity has ten business days to respond. If the electric distribution company or load serving entity seeks to assert that the laws or regulations of the Relevant Electric Retail Regulatory Authority prohibit or condition (which condition is asserted not to have been satisfied) the participation of end-use customers in PJM's program, it is required to provide to PJM, within the ten business days, either (a) an order, resolution, or ordinance of the Relevant Electric Retail Regulatory Authority prohibiting or conditioning the participation of end-use customers; (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law prohibiting or conditioning the participation of end-use customers, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law prohibiting or conditioning the participation of end-use customers. If the electric distribution company or load serving entity does not respond, PJM is

[1] With respect to utilities that distributed less than four million MWh in the previous fiscal year, the relevant retail regulatory authorities have to affirmatively "opt in" for eligible retail customers to be able to participate.

entitled to assume that there is no prohibition or condition related to the participation of end-use customers.

To date, Dominion has received expressions of interest from third parties and North Carolina retail customers, and it has received requests for the customer-related data needed for registration. The Public Staff has had inquiries from two companies interested in participating in a PJM program as a curtailment service provider on behalf of one or more North Carolina jurisdictional retail customers.

The Public Staff presented this matter to the Commission at its Staff Conference on March 1, 2010, and recommended that the Commission take affirmative action to "opt out" so that retail customers cannot automatically participate in PJM's wholesale market through its demand response programs. To this end, the Public Staff recommended that the Commission issue an order stating that, under North Carolina law, 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. Alternatively, if the Commission preferred to receive comments from interested parties before making such an "opt out" order permanent, the Public Staff recommended that the extent to which Dominion should be proposing programs that allow it to bid demand response on behalf of its retail customers into PJM's wholesale market and whether third parties could and should be allowed to do so subject to the Commission's oversight could be considered in a proceeding with respect to the demand-side management (DSM) programs to be offered by Dominion or in an earlier proceeding, as appropriate.

Dominion appeared at Staff Conference and indicated that it supported the Public Staff's primary recommendation. In response to a question from the Commission, counsel for Dominion stated that approval of various DSM programs was pending before the Virginia State Corporation Commission and that it was unclear at this point when Dominion would be filing an application for DSM program approval in North Carolina.

Because North Carolina is a traditionally regulated state and Dominion's integration into PJM was allowed subject to a variety of conditions intended, among other things, to protect the Commission's jurisdiction the Commission agrees with the Public Staff's position that retail customers cannot lawfully participate in PJM's demand response programs individually or through aggregation by a third party not regulated by the Commission. Accordingly, the Commission concludes that it should issue an order "opting out" so that North Carolina retail customers cannot automatically 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, however, is mindful of 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. If interested North Carolina retail customers are not eligible to participate in PJM's demand response programs, they should have opportunities to participate in programs offered by Dominion. Therefore, although Dominion could not state at Staff Conference a date by which it intended to file such programs for approval in North Carolina, the Commission encourages Dominion to file appropriate demand response programs for

Commission review as soon as possible, and will require such a filing no later than September 1, 2010.

IT IS, THEREFORE, ORDERED as follows:

1. 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; and

2. That Dominion shall file for approval appropriate demand response programs for its North Carolina retail customers as soon as possible and no later than September 1, 2010.

ISSUED BY ORDER OF THE COMMISSION.
This the 11th day of March, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Kc031010.01

ELECTRIC COOPERATIVE – FILINGS DUE PER ORDER OR RULE

DOCKET NO. EC-83, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Petition by GreenCo Solutions, Inc. for Approval of Proposed Energy Efficiency Programs	))	ORDER APPROVING ENERGY EFFICIENCY PROGRAMS

BY THE COMMISSION: On January 29, 2010, GreenCo Solutions, Inc. (GreenCo) filed a request for approval of eleven energy efficiency (EE) programs on behalf of its member-cooperatives, which are electric membership corporations (EMCs),[1] owned or governed by their customers or members. The eleven programs[2] are as follows:

1. Agricultural Efficiency Program
2. Commercial Energy Efficiency Program
3. Commercial New Construction Program
4. Community Efficiency Campaign
5. Community Efficiency Campaign (Low-Income)
6. Energy Cost Monitor Program
7. Energy Star Appliances Program
8. Energy Star Lighting Program
9. Residential New Home Construction Program
10. Refrigerator/Freezer Turn-in Program
11. Water Heating Efficiency Program

Under Rule R8-68, the comments of the Public Staff or any other intervenor on GreenCo's application were due on March 1, 2010. On February 25, 2010, the Public Staff filed a motion to extend the time for filing its comments to April 5, 2010. The Commission allowed the Public Staff's request by Order issued March 1, 2010. On April 1, 2010, the Public Staff filed a second motion to extend the time until May 5, 2010 for filing its comments. The Public Staff stated that GreenCo was working to answer the Public Staff's data request regarding this matter and that additional time was needed to complete this work. The Commission allowed the Public Staff's request by Order issued April 6, 2010. On May 5, 2010, the Public Staff filed for a third extension of time to file comments. The Public Staff stated that the Public Staff and GreenCo had engaged in ongoing discussions regarding GreenCo's proposed programs. Based on those discussions, the Public Staff anticipated that GreenCo would file an update to its application on or about May 5, 2010. Therefore, the Public Staff requested an extension to May 17, 2010, for

[1] At the time of its program filing, GreenCo's members included: Albemarle EMC, Blue Ridge EMC, Brunswick EMC, Cape Hatteras Electric Cooperative, Carteret-Craven Electric Cooperative, Central EMC, Edgecombe-Martin County EMC, Four County EMC, French Broad EMC, Haywood EMC, Jones-Onslow EMC, Lumbee River EMC, Pee Dee EMC, Piedmont EMC, Pitt & Green EMC, Randolph EMC, Roanoke Electric Cooperative, South River EMC, Surry-Yadkin EMC, Tideland EMC, Tri-County EMC, Union Power Cooperative, and Wake EMC.

[2] As noted in GreenCo's 2009 REPS compliance plan and 2008 REPS compliance report, both of which were filed September 1, 2009, in Docket No. E-100, Sub 124, GreenCo pilot tested nine of these programs beginning in 2008, and reported 29,865 megawatt-hours (MWh) of estimated energy savings from those pilots during 2008. (See page 9 of Bennett Exhibit 1 filed June 28, 2010.)

the filing of its comments. The Commission allowed the Public Staff's request by Order dated May 6, 2010. Also on May 6, 2010, GreenCo filed an amended Energy Efficiency Program Approval Request. On May 10, 2010, GreenCo filed notice advising the Commission that, effective May 1, 2010, Blue Ridge EMC is no longer a member of GreenCo.

On May 17, 2010, the Public Staff filed its Response to Request for Program Approval (Response). In its Response, the Public Staff recommended approval of GreenCo's eleven proposed EE programs and requested that the Commission require GreenCo to file a report on the cost-effectiveness of the eleven EE programs one year after the date of the Commission's order approving them. The Public Staff also requested that the Commission direct GreenCo to revise its application with respect to the Community Efficiency Campaign, the Energy Star Appliance Program, the Refrigerator/Freezer Turn-In Program, and the Water Heating Efficiency Program within ten days of the filing of the Public Staff's Response. On June 16, 2010, GreenCo filed the application revisions for the four programs as requested by the Public Staff.

On June 18, 2010, the Public Staff filed a Motion for Approval on the Pleadings in which it moved the Commission to approve the eleven proposed EE programs submitted by GreenCo on January 29, 2010 and revised by GreenCo on May 6, and June 16, 2010.

Background

GreenCo is a non-profit organization formed on April 16, 2008, by 23 of the 26 EMCs headquartered in North Carolina. (Subsequently, one of the founding members, Blue Ridge EMC, has withdrawn from its participation in GreenCo.) It exists to assist member-cooperatives in complying with the REPS obligations contained in Senate Bill 3. GreenCo provides three primary services: compliance planning and reporting, EE program development and management, and assistance in renewable energy demonstration projects.

On August 18, 2008, GreenCo filed a Request for Waiver, on behalf of its member EMCs, to allow it to file a consolidated renewable energy and energy efficiency portfolio standard (REPS) compliance plan on behalf of its members in Docket No. E-100, Sub 118. By Order dated August 27, 2008, the Commission granted GreenCo's Request for Waiver. Subsequently, on September 18, 2008, GreenCo filed a 2008 REPS compliance plan with the Commission. That 2008 REPS compliance plan describes the eleven EE programs at issue in this proceeding. GreenCo stated its intent that these EE programs help its members meet their REPS requirements. On September 1, 2009, GreenCo filed its 2009 REPS compliance plan on behalf of its members in Docket No. E-100, Sub 124. In that plan, GreenCo stated that it "intends to continue to develop and pilot test energy efficiency programs designed to provide energy savings to meet a portion of the REPS obligation. At this time, GreenCo has not requested Commission approval of any energy efficiency programs but anticipates doing so later this year." By Order dated August 10, 2010, in Docket No. E-100, Sub 124, the Commission accepted GreenCo's 2009 REPS compliance plan.

On May 17, 2010, the Public Staff filed its Response to GreenCo's request for EE program approval. The Public Staff stated that it believed that the Commission may incorporate by reference GreenCo's request to file REPS compliance plans on behalf of its member-cooperatives in Docket No. E-100, Sub 118 into the present docket as a request to also file EE program applications on behalf of its members.

G.S. 62-133.9(c) states that:

> Each electric power supplier to which G.S. 62-110.1 applies shall include an assessment of demand-side management and energy efficiency in its resource plans submitted to the Commission and shall submit cost-effective demand-side management and energy efficiency options that require incentives to the Commission for approval.

G.S. 62-110.1(b) states that:

> For the purpose of this section, "public utility" shall include any electric membership corporation operating within this State. . . ."

G.S. 62-133.8(c)(2) provides that an EMC may meet its REPS obligation by several means, including:

> b. Reduce energy consumption through the implementation of demand-side management or energy efficiency measures.

Based on the statutes cited above, the Commission finds and concludes that GreenCo's members are required to file for Commission approval cost-effective EE programs that require customer incentives. Based on the Waiver that the Commission granted to GreenCo on August 27, 2008, in Docket No. E-100, Sub 118, the Commission finds and concludes that GreenCo is appropriately filing, on behalf of its member EMCs, the eleven EE programs for Commission approval, and that those program applications are appropriately before the Commission pursuant to Commission Rule R8-68.

G.S. 62-133.8(a)(4) defines an "energy efficiency measure" as follows:

> (4) 'Energy efficiency measure' means an equipment, physical, or program change implemented after 1 January 2007 that results in less energy used to perform the same function. 'Energy efficiency measure' includes, but is not limited to, energy produced from a combined heat and power system that uses nonrenewable energy resources. 'Energy efficiency measure' does not include demand-side management.

GreenCo's Proposed EE Programs

GreenCo has requested approval of eleven EE programs, each of which is described later in this Order: (1) Agricultural Efficiency Program, (2) Commercial Energy Efficiency Program, (3) Commercial New Construction Program, (4) Community Efficiency Campaign, (5) Community Efficiency Campaign (Low-Income), (6) Energy Cost Monitor Program, (7) Energy Star Appliances Program, (8) Energy Star Lighting Program, (9) Residential New

Home Construction Program, (10) Refrigerator/Freezer Turn-in Program, and (11) Water Heating Efficiency Program. According to GreenCo's application, the decision to offer a particular EE program rests with the board of directors of each member-cooperative. Similarly, each board of directors will determine the amount of incentive to be paid by that EMC to its customers who participate in a particular EE program. All eleven of the programs are expected to be on-going. Participating member-cooperatives will use a variety of methods to communicate about the programs to their customers, including direct mail, member newsletters, in-office displays and advertising in the Carolina Country magazine. According to GreenCo, the programs do not affect their customers' decisions to install electric service versus natural gas service. GreenCo states that the most recent North Carolina Electric Membership Corporation (NCEMC) Integrated Resource Plan (IRP), as well as the IRPs for GreenCo's member-cooperatives that are not covered by the NCEMC IRP (Piedmont EMC and French Broad EMC), show savings from each of the proposed programs. The proposed programs all contribute to those energy savings for the participating member-cooperatives.

GreenCo's program applications rely extensively on a December 7, 2007 Energy Efficiency Potential Study that was developed by GDS Associates, Inc., (the GDS Study) for NCEMC. GreenCo submitted the GDS Study on September 12, 2008, in Docket No. E-100, Sub 118. The Public Staff noted in its May 17, 2010 Response that it would be administratively burdensome for each individual EMC to file on its own behalf when the EE programs to be offered by each EMC are essentially the same. NCEMC's membership overlaps extensively with that of GreenCo,[1] making the GDS Study a reasonable starting place from which GreenCo can develop EE programs on behalf of its members. The Commission hereby incorporates the GDS Study by reference into this Docket.

Agricultural Efficiency Program

GreenCo's Agricultural Efficiency Program is intended to encourage agricultural customers to adopt EE measures in farming operations. Each participating GreenCo member-cooperative will offer an energy audit to each participant to determine the EE measure(s) that are appropriate for that participant. Lighting will be the primary focus of the program; however, EE measures for other energy intensive processes such as ventilation and pumping will be considered. Six member-cooperatives[2] anticipate offering this program to their agricultural customers. Each participating member-cooperative's board of directors will decide what financial incentives, which could include loans and rebates, to offer potential program participants.

GreenCo estimates a range of from 262 customer-participants in 2010 to 194 customer-participants in 2017. GreenCo further estimates that the program will result in energy savings of

[1] NCEMC has 21 members: Albemarle EMC, Brunswick EMC, Cape Hatteras Electric Cooperative, Central EMC, Edgecombe-Martin County EMC, Four County EMC, Halifax EMC, Haywood EMC, Jones-Onslow EMC, Lumbee River EMC, Pee Dee EMC, Pitt & Greene EMC, Randolph EMC, Roanoke Electric Cooperative, South River EMC, Surry-Yadkin EMC, Tideland EMC, Tri-County EMC, Union Power Cooperative, and Wake EMC.

[2] Central EMC, Four County EMC, Lumbee River EMC, Pee Dee EMC, Randolph EMC, and South River EMC intend to participate in this program.

3,720 megawatt-hours (MWh) in 2010, increasing to 12,371 MWh in 2017. GreenCo anticipates the total annual program costs will be $183,329 in 2010, decreasing to $135,489 in 2017.

Commercial Energy Efficiency Program

GreenCo's Commercial Energy Efficiency Program is intended to encourage commercial customers to implement EE measures in existing commercial buildings. The EE measures target lighting; heating, ventilation and air-conditioning systems; motors and drives; and refrigeration. The appropriate measure(s) will be determined through an energy audit. Four member-cooperatives[1] anticipate offering this program to their commercial customers. Each participating member-cooperative's board of directors will decide what financial incentives, which could include loans and rebates, to offer potential program participants.

GreenCo estimates a range of from 41 customer-participants in 2010 to 85 customer-participants in 2017. GreenCo further estimates that the program will result in energy savings of 3,356 MWh in 2010, growing to 34,678 MWh in 2017. GreenCo estimates the annual program costs at $445,575 in 2010, increasing to $920,856 in 2017.

Commercial New Construction Program

This program is designed to promote the consideration of energy efficiency during commercial building design. Participating customers will be offered incentives to incorporate energy efficiency design elements into new buildings. Two member-cooperatives, Brunswick and Wake EMC, anticipate participating in this program, and their individual boards of directors will determine the program incentives to be offered.

GreenCo estimates from one to five customer-participants a year, with energy savings ranging from 64 MWh in 2010 to 670 MWh in 2017. GreenCo further estimates the annual program costs at $17,697 in 2010, increasing to $107,726 in 2017.

Community Efficiency Campaign

This program is designed to promote the installation of EE measures that increase the thermal efficiency of a residential building's envelope. The program is targeted at residential communities in order to maximize participation and contractor efficiency. The program targets duct leaks, attic insulation and air leakage. GreenCo member-cooperatives approve the program contractors, which will market the program, address customer intake, schedule work, conduct the initial home visit, install the EE measures and perform quality assurance. Nine member-cooperatives[2] anticipate participating in the program, and their individual boards of directors will determine the program incentives to be offered.

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[1] Carteret-Craven Electric Cooperative, Four County EMC, Lumbee River EMC, and Piedmont EMC intend to participate in this program.

[2] Albemarle EMC, Cape Hatteras Electric Cooperative, Four County EMC, Lumbee River EMC, Randolph EMC, Roanoke Electric Cooperative, Surry-Yadkin EMC, Tri-County EMC, and Wake EMC intend to participate in this program.

GreenCo estimates 2,005 customer-participants in 2010, increasing to 4,161 participants in 2017, with energy savings ranging from 9,021 MWh in 2010 to 62,408 MWh in 2017. GreenCo further estimates that this program will cost $3.2 million in 2010, increasing to $5.9 million in 2017.

Community Efficiency Campaign (Low-Income)

This program is essentially identical to the Community Efficiency Campaign discussed above, except that it will target households with annual incomes of up to 150% of federal poverty guidelines, and the efficiency measures will be provided to eligible customers at no cost to them. The same nine member-cooperatives that plan to offer the Community Efficiency Campaign will also offer the low-income version of the program.

GreenCo estimates that 176 customers will be served by the program in 2010, increasing to 311 in 2017. GreenCo further estimates that the program will cost $232,419 in 2010, increasing to $410,533 in 2017; and that it will save 949 MWh in 2010, increasing to 5,590 MWh in 2017.

Energy Cost Monitor Program

This program is designed to promote energy consumption awareness by residential consumers by giving them information about the amount of electricity they are using on a real-time basis. The program will offer consumers a variety of energy monitoring devices, with the specific devices offered changing over time as technology improves. The participating member-cooperatives will offer the devices to their residential customers at no cost or at a discounted price. Eighteen member-cooperatives[1] anticipate participating in this program, with each organization's board of directors deciding whether/how much to charge for the monitor.

GreenCo estimates that 5,648 monitors will be installed in 2010, increasing to 9,972 monitors in 2017. GreenCo estimates that the program will cost $1.4 million in 2010, increasing to $2.5 million in 2017. The program is estimated to save 8,872 MWh in 2010, increasing to 65,782 MWh in 2017.

Energy Star Appliances Program

This program promotes the use of energy efficient appliances in residences. The program focuses on replacing existing appliances with more efficient ones that have the Energy Star rating. Participating member-cooperatives[2] will offer incentives that could include a direct rebate, the chance to win a cash price, or the opportunity to pay for the appliance in monthly

[1] Albemarle EMC, Brunswick EMC, Cape Hatteras Electric Cooperative, Carteret-Craven Electric Cooperative, Central EMC, French Broad EMC, Haywood EMC, Jones-Onslow EMC, Lumbee River EMC, Pee Dee EMC, Piedmont EMC, Pitt & Greene EMC, Randolph EMC, Roanoke Electric Cooperative, South River EMC, Surry-Yadkin EMC, Tri-County EMC, and Wake EMC intend to participate in this program.

[2] Albemarle EMC, Brunswick EMC, Four County EMC, French Broad EMC, Jones-Onslow EMC, Lumbee River EMC, Piedmont EMC, Roanoke Electric Cooperative, South River EMC, Surry-Yadkin EMC, Tideland EMC, Tri-County EMC, and Wake EMC intend to participate in this program.

increments on one's electricity bill. The board of directors of each participating member-cooperative will determine the specific incentives that it will offer its customers.

GreenCo estimates that 3,873 customers will participate in the program in 2010, increasing to 5,444 in 2017. GreenCo estimates that the program will cost $261,234 in 2010, increasing to $367,164 in 2017. GreenCo further estimates that the program will save 1,708 MWh in 2010, increasing to 8,003 in 2017.

Energy Star Lighting Program

This program will promote efficient lighting in residences. Initially it will focus on replacing incandescent lighting with compact fluorescent lamps that have the Energy Star rating. In the future it will promote the next generation of efficient lighting, such as light-emitting diodes (LEDs). Participating member-cooperatives[1] will offer Energy Star lighting to their residential customers at no cost or at a discounted price, with the ultimate decision on pricing made by each member-cooperative's board of directors.

GreenCo estimates that 350,163 efficient lamps will be installed annually under this program, increasing to 772,279 in 2017. GreenCo estimates the program will cost $1.6 million in 2010, increasing to $3.5 million in 2017. GreenCo further estimates that the program will save 29,965 MWh in 2010, increasing to 264,351 MWh in 2017.

Residential New Home Construction Program

Participating GreenCo member-cooperatives[2] will encourage the purchase or construction of new homes that meet Energy Star standards such that they are more energy efficient than a home built to the standards of the current residential energy code. The program will target the residential new construction market, particularly residential customers and home builders who are in the process of designing and building new homes. Energy savings are based on heating, cooling and hot water energy use and are expected to be achieved through a combination of the following: high performance windows, controlled air infiltration, upgraded heating and air conditioning systems, tight duct systems, high efficiency water heating equipment, and high efficiency building envelopes. Participating member-cooperatives will use consumer education and rebates to encourage the construction of homes built to Energy Star standards. Each participating member-cooperative will decide if the incentive will be offered to the home-owner or the builder, or shared between the two.

GreenCo estimates that in 2010, 201 homes will be built under this program, increasing to 1,472 homes in 2017. GreenCo estimates that the program will cost $369,509 in 2010,

[1] Albemarle EMC, Brunswick EMC, Carteret-Craven Electric Cooperative, Central EMC, Edgecombe-Martin County EMC, Four County EMC, French Broad EMC, Haywood EMC, Jones-Onslow EMC, Lumbee River EMC, Pee Dee EMC, Piedmont EMC, Pitt & Greene EMC, Randolph EMC, Roanoke Electric Cooperative, South River EMC, Tideland EMC, Tri-County EMC, Union Power Cooperative, and Wake EMC intend to participate in this program.

[2] Brunswick EMC, Central EMC, Jones-Onslow EMC, Lumbee River EMC, Piedmont EMC, Randolph EMC, and Wake EMC intend to participate in this program.

increasing to $2.3 million in 2017. GreenCo further estimates that this program will save 864 MWh in 2010, increasing to 16,127 MWh in 2017.

Refrigerator/Freezer Turn-in Program

This program promotes the removal of operational second refrigerators/freezers in residences and ensures that these appliances are dismantled and retired. The appliance must be in operating condition. The participating member-cooperative, at this time only Tideland EMC, will require that all refrigerators/freezers are properly dismantled and delivered to a recycling facility. The incentives could include a rebate or electric bill credit. The board of directors for the participating member-cooperative will determine the incentives that will be offered to its customers.

GreenCo estimates that 90 appliances will be removed in 2010, increasing to 122 in 2017. GreenCo estimates that this program will cost $15,012 in 2010, increasing to $20,266 in 2017. GreenCo further estimates that this program will save 526 MWh in 2010, increasing to 2,365 MWh in 2017.

Water Heating Efficiency Program

This program is designed to reduce the heat loss from residential electric water heating equipment. The program will focus on installing four low-cost water heating EE measures: a water heater blanket, pipe wrap, low-flow aerators and low-flow showerheads. These will be marketed as a kit to residential customers at a discounted price. The board of directors for each participating member-cooperative[1] will decide the exact level of incentives to offer its customers.

GreenCo estimates that 7,088 kits will be installed under the program in 2010, increasing to 9,569 in 2017. GreenCo estimates that the program will cost $512,086 in 2010, increasing to $691,316 in 2017. GreenCo further estimates that the program will save 19,990 MWh in 2010, increasing to 89,953 MWh in 2017.

Measurement & Verification

Because GreenCo does not seek cost recovery under G.S. 62-133.9(d) or Rule R8-69, Rule R8-68 does not require that GreenCo submit measurement and verification (M&V) information when applying for Commission approval of a new EE or DSM program. Nevertheless, GreenCo did provide information regarding its M&V plans for the proposed EE programs. Because GreenCo intends to use savings from the eleven programs to comply with REPS, it stated that it will be responsible for conducting M&V studies on behalf of its member-cooperatives, using standard industry-accepted methods, and it will report the energy savings in the aggregate on behalf of GreenCo members through the REPS reporting process. The Public Staff stated that, in response to data requests, GreenCo provided M&V information that is fairly

[1] Albemarle EMC, Cape Hatteras Electric Cooperative, Central EMC, Four County EMC, Haywood EMC, Jones-Onslow EMC, Lumbee River EMC, Pee Dee EMC, Piedmont EMC, Pitt & Greene EMC, Randolph EMC, Roanoke Electric Cooperative, South River EMC, Surry-Yadkin EMC, Tideland EMC, Tri-County EMC, Union Power Cooperative, and Wake EMC intend to participate in this program.

consistent with the information provided by electric public utilities when they seek Commission approval of EE and DSM programs, and that the Public Staff intends to scrutinize the results of GreenCo's M&V of energy savings used to comply with REPS during REPS proceedings.

Cost-Effectiveness Evaluations

The cost-effectiveness analyses conducted on the eleven programs rely heavily on the GDS Study and its assumptions regarding size of incentives to be paid to participating customers. GreenCo stated in its application that the data to support program costs, participant levels, and energy and demand savings is based on research conducted on behalf of all of the North Carolina electric cooperatives in the GDS Study. GreenCo adjusted the participant numbers and projected savings when necessary to better match anticipated results, given the sub-set of member-cooperatives choosing to participate in each particular program. Similarly, GreenCo adjusted the administrative cost estimates. The Public Staff stated that, after discussion with GreenCo and review of its application and the GDS Study, the Public Staff believes that GreenCo's estimates of program costs, participants and energy savings are reasonable and appropriate.

The estimate of an electric power supplier's avoided costs is another key component of cost-effectiveness analyses for EE programs. The Public Staff stated that it believes that the avoided costs used to determine the cost-effectiveness of GreenCo's proposed programs are consistent with the avoided costs associated with NCEMC's 2009 IRP.

The Public Staff reviewed the cost-effectiveness evaluations for the eleven programs and found that all of the programs are cost-effective from the perspective of the total resource cost test, the participant cost test and the utility cost test. However, none of the eleven programs are cost-effective from the perspective of the rate impact measure test. The Public Staff also noted that all of the proposed programs have a total resource cost test score of 1.05 or better. The Public Staff stated that it has reviewed all of the proposed programs very carefully and believes that, based on the information provided by GreenCo, they are generally cost-effective. The Public Staff believes that because this is GreenCo's first set of proposed EE programs, it should file a report next year with the Commission in this Docket, so that the Commission may determine the continued cost-effectiveness of the programs.

The Commission finds that GreenCo's eleven programs are generally cost effective and in the public interest. The Commission will, therefore, approve them. However, the Commission agrees with the Public Staff that further study of the programs' cost effectiveness is appropriate. The Commission notes that each participating EMC board of directors will decide the level of incentives to offer its customers for participating in each program. To the extent they differ from the assumptions in the GDS Study, the actual incentive levels paid could change the programs' cost-effectiveness. In addition, GreenCo's application indicated the participation of Blue Ridge EMC in several of the programs,[1] but on May 10, 2010, GreenCo informed the Commission that Blue Ridge EMC is no longer a member of GreenCo. Since Blue Ridge EMC will not be

[1] GreenCo's application lists Blue Ridge EMC as a participant in the following programs: Community Efficiency Campaign, Community Efficiency Campaign (Low Income), Energy Cost Monitor, Energy Star Appliances, Energy Star Lighting, Refrigerator/Freezer Turn In, and Water Heating Efficiency.

participating in the GreenCo EE programs, the cost-effectiveness analyses need to be revised. Therefore, the Commission will require GreenCo to file an updated report one year from the date of this Order regarding the cost-effectiveness of the eleven programs. The report should be based on the customer incentives approved by the board of directors of each participating member-cooperative.

IT IS, THEREFORE, ORDERED as follows:

1. That the eleven EE programs filed by GreenCo on behalf of its member-cooperatives are approved.

2. That, not later than one year from the date of issuance of this Order, GreenCo shall file updated cost-effectiveness information for the eleven programs, which information will be based on the actual level of incentives established by each participating member-cooperative.

3. That GreenCo shall file in this Docket the GDS Study that is referenced in its Request for EE Program Approval.

ISSUED BY ORDER OF THE COMMISSION.
This the 23rd of August, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Renné Vance, Chief Clerk

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FERRIES – RATE INCREASE

DOCKET NO. A-41, SUB 7

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Petition of Bald Head Island Transportation, Inc. for a General Increase in Rates and Charges	)))	ORDER DENYING MOTION IN LIMINE

BY THE PRESIDING COMMISSIONER: On October 11, 2010, Bald Head Transportation, Inc. (BHIT) filed a Motion in Limine to Exclude Portions of Prefiled Direct Testimony of Julius A. Wright, PH.D.—namely, those parts of Dr. Wright's testimony that offer ultimate legal conclusions regarding whether the Commission has the authority to regulate, or impute to Bald Head Island Transportation, Inc. (BHIT) the revenue from, the parking operations as "ancillary services" under North Carolina legal precedents. Under the Motion, the following portions of Dr. Wright's prefiled testimony should be stricken: Page 8, line 20, through page 9, line 12 and page 11, line 5, through page 12, line 11. BHIT cited to Rule R1-7, R-1-24, and G.S. 8C-1, Rule 702.

BHIT maintained that the above portions parts of Dr. Wright's testimony were legal conclusions and are not the proper subject of expert testimony. While an expert witness may offer opinions regarding the factual premises of an ultimate legal issue, an expert's testimony is not admissible where it "suggests whether legal conclusions should be drawn or whether legal standards are satisfied." *HAJJM Co. v. House of Raeford Farms, Inc.*, 328 N.C. 578, 5587 (1991) (*HAJJM*). It is the sole province of the court to "determine the applicable law." *Id.*

On October 14, 2010, the Bald Head Island Association, the Bald Head Island Club, and the Village of Bald Head Island (The Customer Group or TCG) filed a Joint Response to BHIT's Motion in Limine. Contrary to the BHIT's view, TCG argued that the disputed testimony does not offer an "ultimate legal conclusion." Moreover, even if it did, admission of this relevant testimony would be useful to the Commission based on Dr. Wright's years of regulatory and lawmaking experience, including three terms in the North Carolina Senate, a North Carolina Utilities Commissioner for eight years, and many years of consulting on utility regulatory matters.

TCG further argued that the bulk of the testimony that BHIT seeks to exclude are simply statements of opinion as to underlying matters of fact—i.e., that the parking service provided to ferry passengers at the Deep Point Ferry is an "ancillary service" which is an integral part of the service offered to the public by BHIT and that the parking lot facilities at that terminal are "ancillary facilities" used in connection with BHIT's provision of service to the public. The judicial opinions cited by Dr. Wright are matters of public record that a witness can certainly cite, and the statements of the witness's opinion on that matter are analogous to statements of fact and/or expressions of opinion.

Rule 702 of the North Carolina Rules of Evidence, cited by BHIT, provides that "[i]f scientific, technical, or other specialized knowledge will assist the trier of fact to understand the evidence or to determine a fact in issue, a witness qualified as an expert by knowledge, skill, experience, training or education, may testify thereto in the form of an opinion." Similarly, Rule 704 provides that "[t]estimony in the form of an opinion or inference is not objectionable because it embraces an ultimate issue to be decided by the trier of fact." Dr. Wright has such specialized knowledge, skill, experience, training and education. In any event, the rationale behind the North Carolina cases proscribing the application of Rule 704 to certain kinds of expert testimony is not present here. The concern was that such testimony should not invade the trial court's "province to determine the applicable law and to instruct the jury on it." *HJJM* at 587. In the context of Commission proceedings, this concern for the jury is not present. *See,* also, G.S. 62-65 ("When acting as a court of record, the Commission shall apply the rules of evidence applicable to all civil action in the superior court, *insofar as practicable....*" Emphasis added). Furthermore, in the instant case, there is no legal "standard" or specific set of legal criteria at issue, so concerns in this case that an expert witness might mislead the decision-makers as to the appropriate legal standard are absent, and the Commission is accordingly free to allow such testimony.

WHEREUPON, the Presiding Commission concludes that good cause exists to deny BHIT's Motion in Limine. This proceeding is both judicial and administrative in nature, and G.S. 62-65's use of the language "insofar as practicable" gives the Commission leeway not to apply the strict rules of evidence that might otherwise apply in the General Court of Justice in a case before a jury. Moreover, Dr. Wright's background as a former Utilities Commissioner, where he acquired intimate knowledge of the specialized area of utilities regulation, his education, skill, and experience qualify him to offer his expert opinion as to the legal question before the Commission. It is not unusual that expert witnesses appearing before the Commission express opinions pertinent to issues bearing in part on legal determinations, and the Commission is capable of avoiding undue influence in determining for itself how the laws should be interpreted. Dr. Wright's testimony will be judiciously considered by the Commission, and the Commission will give it appropriate appropriate weight.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 15th day of October, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

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FERRIES – RATE INCREASE

DOCKET NO. A-41, SUB 7

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	
Application of Bald Head Island Transportation, Inc. for a General Increase in its Rates and Charges Applicable to Ferry Service Between Southport, North Carolina and Bald Head Island, North Carolina)	ORDER GRANTING PARTIAL RATE INCREASE AND REQUIRING NOTICE

HEARD: Friday, July 23, 2010, at 10:00 a.m., Ocean Room, Bald Head Island Club, 301 Salt Meadow Trail, Bald Head Island, North Carolina

Wednesday, October 20, 2010, 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, and Commissioners Bryan E. Beatty and Lucy T. Allen

APPEARANCES:

For Bald Head Island Transportation, Inc.:

M. Gray Styers, Jr. and Charlotte Mitchell, Styers & Kemerait PLLC, 1001 Haynes Street, Suite 101, Raleigh, North Carolina 27604

For Bald Head Island Club:

Daniel C. Higgins, Burns, Day & Presnell, P.A., P.O. Box 10667, Raleigh, North Carolina 27605

For Bald Head Association, Inc.:

Odes L. Stroupe, Jr., Bode, Call and Stroupe, LLP, 3105 Glenwood Avenue, Suite 300, Raleigh, North Carolina 27612

For The Village of Bald Head Island:

Mary Lynne Grigg, McGuire Woods, LLP, 2600 Two Hannover Square, Raleigh, North Carolina 27601

For the Using and Consuming Public:

FERRIES – RATE INCREASE

Dianna Downey, Staff Attorney, and Antoinette Wike, Chief Counsel, Public Staff-North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: On May 5, 2010, Bald Head Island Transportation, Inc. (BHIT or Company) filed an application for a general rate increase, pursuant to G.S. 62-133 and G.S. 62-134 and Commission Rules R1-4, R1-5, and R1-17, along with the direct testimony and exhibits of James W. Fulton, Jr., Vice President of BHIT and Director of Operations for Bald Head Island Limited, LLC (BHIL); Shirley A. Mayfield, Secretary/Treasurer of BHIT and Chief Financial Officer of BHIL; and Fredrick W. Hering, outside consultant who is providing regulatory accounting services to BHIT. In its application, BHIT requested an increase in rates, fares, and operating revenues designed to produce an overall increase of $2,767,548 in annual ferry operating revenues. On May 28, 2010, BHIT filed an amendment and/or clarification to its petition for a general rate case seeking to clarify the date rates were to become effective.

Motions to Intervene were filed by Bald Head Island Club (Club) on May 12, 2010, by The Village of Bald Head Island (Village) on May 19, 2010 and by Bald Head Association (BHA or Association) on June 7, 2010. The Commission granted intervention in this proceeding to the Club, the Village, and the Association (the Customer Group) by Orders dated June 3, 2010 and June 10, 2010.

On June 3, 2010, the Commission entered an Order Establishing General Rate Case, Suspending Rates, Scheduling Hearings, Requiring Public Notice, and Granting Petitions for Leave to Intervene. In accordance with that Order, a public hearing was conducted at the Bald Head Island Club on Bald Head Island on July 23, 2010. At the hearing, the following persons testified: Suzanne Dorsey, Brenda Quanstrom, Richard Mesaris, Sylvia Poole, Marilyn Ridgeway, Jane Johnson, John Earle, Harry Aylor, Barbara McQuaide, Patricia Garrett, Wendie Walker, Clark Pennell, Douglas Ledgett, Donna Finley, Donna Jarmusz, Norm Coryell, Timothy O'Brien, Erica Grantmyre, Bob Liesegang, Joseph Elrod, Larry Lammert, William Waddell, Patricia Barnard, Larry Patterson, Darren Witt, David Adcock, Nancy Giacci, and Sandra Hall.

On July 8, 2010, the Company provided notice of its filing of affidavits of publication of public notice of hearings as required by the Commission's June 3, 2010 Order.

On August 9, 2010, BHA filed a motion to reschedule the date for the hearing set for September 28, 2010, and on August 11, 2010, BHIT filed its response to BHA's motion. On August 11, 2010, the Village filed a motion for extension of time regarding the deadlines for the filing of testimony and for conducting discovery and BHIT filed a motion requesting to amend the schedule for taking depositions. On August 12, 2010, the Customer Group filed a joint reply to the response of BHIT. On August 13, 2010, BHIT filed its supplemental response to the motions to reschedule the hearing date. On August 17, 2010, the Commission entered an Order Rescheduling Hearing, Requiring Public Notice, and Ruling On Motion to Compel that rescheduled the September 28, 2010 hearing to October 20, 2010, and directed the Public Staff and other intervenors to file direct testimony on or before Monday, September 20, 2010, and BHIT to file rebuttal testimony and exhibits on or before Monday, October 4, 2010.

On September 16, 2010, the Public Staff filed a motion for extension of time to file testimony. In its motion, the Public Staff notified the Commission that the Public Staff and BHIT had reached an agreement and required additional time to file a stipulation and supporting testimony. On September 20, 2010, the Commission entered an Order granting the Public Staff's motion, extending the time to file testimony to September 27, 2010, and the time to file rebuttal testimony to October 11, 2010. On September 27, 2010, the Customer Group filed a motion for extension of time to file testimony, indicating that discussions were ongoing for a global settlement and requesting an extension to September 30, 2010 to file testimony and to October 14, 2010 to file rebuttal testimony. On September 28, 2010, the Commission entered an Order granting the extension of time requested by the Customer Group.

On September 30, 2010, the Public Staff filed an Agreement and Stipulation of Settlement (Agreement) between BHIT and the Public Staff and the testimony of James G. Hoard, Assistant Director, Public Staff Accounting Division. On that same date, the Customer Group filed the testimony of Dr. Julius A. Wright, President of J.A. Wright & Associates, Inc. On October 14, 2010, BHIT filed the rebuttal testimony of Shirley A. Mayfield, Frederick W. Hering, and James W. Fulton, Jr. On October 15, 2010, BHIT filed its proposed order of witnesses and estimate of cross-examination times and also filed the amended rebuttal testimony of Shirley A. Mayfield and Frederick W. Hering. On October 18, 2010, the Customer Group filed a response to BHIT's proposed order of witnesses. On October 19, 2010, the Commission entered an Order Determining Order of Witnesses.

The hearing resumed in Raleigh on October 20, 2010 as scheduled. No public witnesses appeared to testify. Upon becoming informed that substantive negotiations were still underway between the Customer Group, BHIT, and the Public Staff and at the request of all the parties, the Commission adjourned the hearing until October 21, 2010, if needed, to allow the parties additional time to discuss and conclude the ongoing settlement negotiations. On October 21, 2010, the Customer Group, the Public Staff, and BHIT (the Stipulating Parties) entered and filed a Revised Agreement and Stipulation of Settlement (Stipulation) and the late-filed revised exhibits of James G. Hoard. Additionally, BHIL also entered into the Stipulation for the purpose of acknowledging its agreement with its obligations under Section 2.C.i. (Deep Point parking facilities) and Section 8 (Accounting Policies) of the Stipulation. The foregoing Stipulation comprehensively resolved all issues in this proceeding among all of the parties; therefore, the October 21, 2010 hearing was not reconvened. Pursuant to Section 12 of the Stipulation, the Stipulating Parties agreed that all prefiled testimony and exhibits may be received into evidence without objection, and each Stipulating Party waived all rights to cross-examine any witness except to affirm the provisions of the Stipulation and to explain and clarify testimony consistent with the Stipulation. Consequently, the Commission receives into evidence the prefiled direct and rebuttal testimony and exhibits of Shirley A. Mayfield, Frederick W. Hering, and James W. Fulton, Jr.; the prefiled direct testimony and exhibits of James G. Hoard and Dr. Julius A. Wright; and the amended joint rebuttal testimony and exhibits of Company witnesses Mayfield and Hering. Further, the Commission receives into evidence the Stipulation and Stipulation Exhibits, and the late-filed revised exhibits of Public Staff witness Hoard.

After the Stipulation was filed, the Commission received a total of seven emails[1] from customers indicating, among other things, that the proposed rate increase in the Stipulation was unfair and unreasonable and that the Commission should reject the Stipulation and proceed to a further hearing and final ruling on all issues.

On November 22, 2010, the Stipulating Parties filed a Joint Proposed Order.

WHEREUPON, based upon consideration of the verified application, the prefiled direct and rebuttal testimony and exhibits, the amended rebuttal testimony and exhibits, the late-filed revised exhibits, the Stipulation, the Stipulation exhibits, and the record as a whole, the Commission now makes the following

FINDINGS OF FACT AND CONCLUSIONS

1. BHIT is duly organized as a public utility operating under the laws of the State of North Carolina and is subject to the jurisdiction of the North Carolina Utilities Commission pursuant to G.S. 62-3(23)a.3. The Company is engaged in the business of transporting passengers and their personal effects by ferry to and from Deep Point Marina terminal in Southport, North Carolina and the Bald Head Island terminal on Bald Head Island, North Carolina. BHIT is a wholly-owned subsidiary of BHIL.

2. The Commission has jurisdiction over the rates and charges, rate schedules, classifications, and practices of public utilities operating in North Carolina, including BHIT, under Chapter 62 of the General Statutes of North Carolina. BHIL is subject to the jurisdiction of the Commission to the extent provided for in G.S. 62-3(23)c, and BHIL joined in the Stipulation for the purpose of and only to the extent of approving BHIL's obligations under Section 2.C.i. (Deep Point parking facilities) and Section 8 (Accounting Policies) of the Stipulation and incorporating those obligations in this Order.

3. BHIT is lawfully before the Commission based upon its application for a general rate increase in its ferry ticket rates pursuant to G.S. 62-133, G.S. 62-134, and Commission Rule R1-17.

4. The appropriate test period for use in this proceeding, is the 12-month period ended December 31, 2009, updated with actual changes to revenues, expenses, rate base, and cost of capital.

5. In its application, BHIT requested approval of an increase in total annual ferry ticket revenues of $2,767,548 to permit BHIT to earn income of $342,453. The increase requested in the application would have resulted in an overall rate of return per BHIT of 9.25%, a 10.00% return on common equity, and a 8.50% cost of long-term debt, based on an imputed capital structure of 50% long-term debt and 50% common equity.

[1] Four emails were received on October 28, 2010; one email was received on November 2, 2010; and two emails were received on November 15, 2010.

FERRIES – RATE INCREASE

6. The Stipulation filed on October 21, 2010 included revisions to several of the provisions set forth in the September 30, 2010 Agreement and Stipulation between BHIT and the Public Staff and also set forth new provisions that, as revised and expanded, comprehensively resolved all issues in this proceeding among all of the parties. Having carefully reviewed the Stipulation and all of the evidence of record, the Commission finds and concludes that the provisions of the Stipulation are just and reasonable to all parties under the circumstances of this proceeding and should be approved in their entirety. The provisions of the Stipulation are addressed in the following findings of fact and conclusions.

7. Consistent with the Stipulation, the Commission finds and concludes that it is appropriate for BHIT to adjust its rates, fares, and charges to produce annual revenues of $5,094,164 from its ferry operations, which will result in total annual revenues of $5,966,508, including $872,344 of other operating revenues. The Stipulating Parties agreed that these revenues are intended to provide BHIT, through sound management, the opportunity to earn an overall rate of return of 8.33% on a rate base of $3,943,335, with BHIT's long-term debt cost of 6.65% and a rate of return of 10.00% on the member's equity component of the following imputed capital structure:

Long-Term Debt 50%
Member's Equity 50%

The Commission finds and concludes that this aspect of the Stipulation is just and reasonable.

8. Exhibits A and B of the Stipulation summarize the gross revenues, operating revenue deductions, rate base, and rate of return agreed upon by the Stipulating Parties.

9. With respect to the parking operations and facilities at the Deep Point ferry terminal and the property formerly used for parking and ferry operations at Indigo Plantation, the Stipulating Parties agreed as follows:

a. BHIL, the parent affiliate of BHIT, owns certain parking facilities adjacent to the BHIT ferry terminal in Southport (the Deep Point parking facilities). The imputation of the revenues of the Deep Point parking facilities, as described in the testimony and shown in the exhibits of Public Staff witness James G. Hoard, is limited to this case and establishes no binding precedent for future cases, and shall not be binding in future cases as a reason for or against imputation of parking revenues or any other regulatory treatment of parking operations. However, the Stipulating Parties agreed that:

i. Seasonal/Non-Seasonal Daily Parking: BHIL agrees not to increase the price of the Seasonal/Non-Seasonal Daily Parking rates currently in effect ($10 Seasonal; $8 Non-Seasonal) in any one 12-month period in an amount greater than the percentage change in inflation (inflation shall be defined as the Consumer Price Index for All Urban Consumers (CPI-U) as calculated by the U.S. Bureau of Labor Statistics), rounded to the nearest whole 25¢. Any increase in rates due to the CPI-U shall not exceed the compound average growth rate from January 1, 2011. BHIL agrees to be bound by this provision for a period beginning on January 1, 2011, and ending on December 31, 2016. This limitation shall apply through December 31, 2016, to any successor entity that owns, operates, or leases the Deep Point parking facilities.

ii. Annual Parking: BHIL and the Village have a pre-existing understanding and commitment regarding accommodations afforded by BHIL associated with Annual Parking patrons. The understanding between BHIL and the Village is reflected in a letter dated April 24, 2009, attached as Exhibit C to the Stipulation. BHIL agrees to comply with the limitations set forth in the letter of April 24, 2009 with the following amendments: (i) the term "inflation" shall be defined as CPI-U as calculated by the U.S. Bureau of Labor Statistics and (ii) the term set forth in the letter shall be extended through December 31, 2016 and the following additional language shall be added: "*2015 Rates increase not to exceed annual inflation experienced during 2014, and 2016 Rates increase not to exceed annual inflation experienced during 2015.*" Any increase in rates due to the CPI-U shall not exceed the compound average growth rate from January 1, 2011. These limitations shall apply through December 31, 2016, to any successor entity that owns, operates, or leases the Deep Point parking facilities.

iii. BHIL will provide notice to the Public Staff and the Commission of any sale or lease of the Deep Point parking facilities or any part of those facilities not less than 90 days prior to the scheduled closing date for the sale or lease.

iv. BHIL will include, in any contract for the sale or lease of the Deep Point parking facilities, the parking rate limitations described in the Stipulation and in this Order.

v. Any gain or loss on the sale or lease of parking facilities owned by BHIL shall not be assigned, credited, or attributed for ratemaking purposes to BHIT.

b. The applicability of the treatment of the gain on the transfer of the Indigo Plantation property from utility to nonutility property is limited to this case and establishes no precedent in future cases for the regulatory treatment of any property owned by BHIL and leased by BHIT.

c. Notwithstanding the foregoing provisions, nothing in the Stipulation shall be construed to imply any limitation on the Commission's regulatory jurisdiction or ability to exercise its statutory powers and discharge its statutory duties to protect the public interest with respect to the rates charged and service rendered by BHIT pursuant to its grant of common carrier authority from the Commission.

The Commission finds and concludes that these provisions are just and reasonable and should be approved in this Order.

FERRIES – RATE INCREASE

10. As agreed in the Stipulation, in Section 2.D., BHIT's revenues from its ferry operations for the 12 months ended December 31, 2009 (the test period), by customer class under current base rates, and as approved herein, will be as follows:

	Annual Revenues	
Type of Passenger	Current Rates	Approved Rates
Class I General	$1,605,825	$2,462,265
Class II Bulk/Bulk40	272,663	464,415
Class III Group Purchase/Bulk 80	252,150	71,055
Class IV Government Employees	77,211	-
Class V Special Event	21,750	-
Class VI No Frills	110,900	155,260
Class VII Contractor	345,950	484,330
Class VIII Corporate Guest	28,024	-
Class IX Employee	387,128	1,081,822
Class X Children	148,704	225,624
Class XI Annual Pass	33,000	33,300
Class XII Senior Citizen Annual Pass	15,750	-
Class XIII Excess Baggage	65,550	100,510
Class XIV Student Ticket	856	-
Class XV Lost/One-Way Ticket	6,775	15,583
Total	$3,372,236	$5,094,164

The Commission finds and concludes that this provision of the Stipulation is just and reasonable.

11. The Stipulating Parties agreed that the Schedule of Rates and Charges attached as Exhibit D to the Stipulation should be approved, and the Commission finds and concludes that this Schedule of Rates and Charges is just and reasonable.

12. The effective date of the rate change (Effective Date) is January 1, 2011. With respect to issues relating to the renewal and expiration of current tickets held by customers, the Stipulating Parties agreed to the following, as set forth in the Joint Proposed Order:

a. Currently issued Class XI Annual Passes sold at the current rate will continue to be honored for passage until they expire, but no Class XI Annual Passes sold or renewed at the current rate will be honored after December 31, 2011. Annual passes held by agencies or nonresidential property owners that expire after December 31, 2010, will not be renewed. There shall be no proration in value of either a currently issued annual pass or new/renewed annual pass.

b. Currently issued Class XII Senior Citizen Annual Passes will continue to be honored for passage until they expire, but shall not be renewed upon expiration after December 31, 2010. No Class XII Senior Citizen Annual Passes sold or renewed at the current rate will be honored after December 31, 2011. There shall be no proration in value of either a currently issued annual pass or new/renewed annual pass.

c. All other tickets (except Class II Bulk Fare, Class XV Lost Tickets, and Class VI No Frills tickets) shall be honored when used and/or may be presented for refund or credit towards purchase of another ticket through March 31, 2011, but shall expire and have no value after that date. Class II Bulk Fare tickets issued on or before December 31, 2010, will be honored for passage only when used though March 31, 2011, but will be accepted for refund or credit towards purchase of other ticket(s) when presented or returned at any time up to and including June 30, 2011, and will have no value after that date.

The Commission finds and concludes that the foregoing agreement by the Stipulating Parties regarding ticket renewal and expiration dates is just and reasonable.

13. The Stipulating Parties agreed upon the following regarding the rate design changes proposed by BHIT:

a. BHIT shall cancel the Class IV Government Employees; Class V Special Event; Class VIII Corporate Guest; Class XII Senior Citizen Annual Pass; and Class XIV Student Ticket classes, as recommended by BHIT witness Fulton.

b. BHIT shall establish new Bulk 40 and Bulk 80 ticket classes as proposed by BHIT witness Fulton at the rates and as described in the rate schedule and tariff attached to the Stipulation as Exhibits D and E.

The Commission finds and concludes that these rate design changes are just and reasonable.

14. The Stipulating Parties agreed that BHIT's fuel surcharge shall be set at zero as of the Effective Date but agreed that the difference between fuel collections and fuel expenses should continue to be tracked in the fuel tracker account and reported to the Commission on a quarterly basis consistent with present procedures. The revised fuel component of rates recomputed based on the cost of service and billing units from this proceeding is set forth in Exhibit F of the Stipulation. A fuel surcharge adjustment may be requested in the future pursuant to the Commission's January 29, 2009 Order in Docket No. A-100, Sub 0. The Commission finds and concludes that this provision of the Stipulation is just and reasonable.

15. The Stipulating Parties agreed that the depreciation rates for regulatory accounting purposes shall, with the exception of the assets listed on Exhibit G of the Stipulation, be determined by the Company based on the straight-line method and the life of the asset used for federal income tax purposes. The Commission finds and concludes that the depreciation rates applicable to the specific assets listed on Exhibit G are just and reasonable and shall be the rates set forth thereon.

16. In the Stipulation, BHIT agreed that it will, within 30 days after the date of issuance of this Order, file with the Commission amendments to its affiliate agreements with

BHIL that reflect any changes necessary to conform the affiliate agreements with this Order. The Commission finds and concludes that this provision of the Stipulation is just and reasonable.

17. BHIT operates on a calendar year basis ending December 31. In the Stipulation, the Company agreed to submit to the Commission and Public Staff a quarterly financial report of monthly information within 45 days after the end of each quarter. The report shall contain a calendar year-to-date income statement in a format presently produced for internal management purposes, information on the Company's month-end balances of plant, accumulated depreciation, and accumulated deferred taxes by plant category, monthly book depreciation expense by plant category, the number of customers by fare class for each month, and the number of tram riders by month. The quarterly reports to be provided in this regard should be filed with the Commission as "non-confidential" filings available to the public. The Commission finds and concludes that this provision of the Stipulation is just and reasonable.

18. The Stipulation provides that the Public Staff shall perform an audit (in accordance with the scope and process generally employed in connection with this docket) of BHIT, and file a report with the Commission regarding the earnings of BHIT and a recommendation as to whether the Public Staff believes there are grounds for requiring BHIT to show cause why its rates should not be reduced or increased for service rendered thereafter. The audit shall be commenced on the earlier of the following: (1) six years from the entry of the Approval Order or (2) the date BHIT's ferry ticket revenues as reported in BHIT's quarterly reports for any Reporting Period are 5% greater than the immediately preceding Reporting Period or the date BHIT's ferry ticket revenues as reported in BHIT's quarterly reports for any Reporting Period are 5% less than the immediately preceding Reporting Period. For purposes of this subsection, the Reporting Period shall be defined as the 12-month period ending with the quarterly report most recently filed with the Commission. The Stipulating Parties agreed that nothing contained in the Stipulation shall prevent BHIT from filing a general rate case or the Public Staff, any Stipulating Party, or any person from initiating a proceeding with the Commission regarding BHIT's rates, earnings, or service at any time. The Commission finds and concludes that this provision of the Stipulation is just and reasonable.

19. The Company employs a modified tax basis of accounting for regulatory reporting purposes. The financial statements produced by the Company for internal management purposes are prepared on a tax basis of accounting. The tax-basis financial statements are modified for regulatory reporting purposes to reflect book depreciation expense. The Company agreed in the Stipulation that it will use the same asset capitalization and asset retirement policies for regulatory reporting purposes that it uses for tax purposes. The Company and BHIL also agreed that consistent with codes of conduct governing transactions between other utilities regulated by the Commission and their unregulated affiliates, charges to the Company from affiliates will be priced at the lower of cost or fair market value and that charges by the Company to affiliates will be priced at the higher of cost or fair market value. The Commission finds and concludes that this provision of the Stipulation is just and reasonable.

20. Consistent with Section 9 of the Stipulation, the Commission finds and concludes that the overall quality of service provided by BHIT is good.

21. The Stipulation provided that, except as provided in the Stipulation, the Stipulation shall not be construed to allow, support, confer, or provide a basis for Commission regulation or jurisdiction over rates, service, or complaints regarding parking services provided by BHIL, or the assets utilized for those services, in this rate case. The Commission finds and concludes that this provision of the Stipulation is just and reasonable.

EVIDENCE IN SUPPORT OF FINDINGS OF FACT
AND CONCLUSIONS NOS. 1 THROUGH 3

The evidence supporting these findings of fact and conclusions is contained in the verified general rate case application, BHIT's direct and rebuttal testimony and exhibits, the testimony, exhibits, and revised exhibits of James G. Hoard, the Stipulation, and the entire record in this proceeding. These findings and conclusions are informational, procedural, and jurisdictional in nature and are not contested by any party.

EVIDENCE IN SUPPORT OF FINDINGS OF FACT
AND CONCLUSIONS NOS. 4 THROUGH 6

The evidence supporting these findings of fact and conclusions is contained in the verified general rate case application, BHIT's direct and rebuttal testimony and exhibits, the testimony and exhibits of Dr. Julius A. Wright, the testimony, exhibits, and revised exhibits of James G. Hoard, the Agreement (filed September 30, 2010), the Stipulation (filed October 21, 2010), the Stipulation Exhibits, and the entire record in this proceeding.

The Stipulation, among all of the parties, entered and filed on October 21, 2010, included revisions to several of the provisions set forth in the September 30, 2010 Agreement between BHIT and the Public Staff, and also set forth new provisions that, as revised and expanded, comprehensively resolved all issues in this proceeding among all of the parties. In particular, the revisions and additions included in the October 21, 2010 Stipulation are briefly summarized as follows:

(1) Exhibit A attached to the Stipulation provided that the Stipulating Parties have agreed to a revenue increase of $1,721,928, which incorporated a revenue decrease of $144,133 from the revenue increase that had been reflected in the Agreement; and it is $1,045,620, or 38% less than the increase that BHIT requested in its application. An "Other revenue adjustment" column was added to Hoard Exhibit 1, Schedule 3 Revised, which was filed on October 21, 2010, to reflect such agreed-upon annual revenue decrease.

(2) Stipulation Section 2.C.i.a., regarding Seasonal/Non-Seasonal Daily Parking was added as an entirely new (additional) provision. This Section imposed limitations (tied to the percentage change in inflation) on the amount by which BHIL may increase the prices of the Seasonal/Non-Seasonal Daily Parking rates currently in effect ($10.00 Seasonal and $8.00 Non-Seasonal); and it was agreed that BHIL shall be bound to this provision for the period beginning January 1, 2011 and ending December 31, 2016.

(3) In Stipulation Section 2.C.i.b., Annual Parking, BHIL agreed to be bound to certain limitations (tied to the percentage change in inflation) on the amount by which it may increase the prices of the annual parking rates through December 31, 2016. Whereas, in the Agreement, BHIL had agreed to similar provisions, but it would be bound for five years from the date of the Commission's Order adopting the Stipulation, rather than six years. Additionally, language was added referencing a letter dated April 24, 2009, which was attached to the Stipulation as Exhibit C, which addresses an understanding between the Village and BHIL, as to BHIL's annual parking rate commitment regarding changes in rates through 2014. As a result of the Stipulation, the terms of the letter were extended through December 31, 2016.

(4) Stipulation Section 2.C.i.c. included a modification to the timeframe for providing notice that BHIL is required to provide to the Commission and the Public Staff of any sale or lease of the Deep Point parking facilities or any part of those facilities. In the Agreement, BHIL had agreed to 30 days notice; whereas, the Stipulation provides that BHIL shall provide notice to the Commission and the Public Staff not less than 90 days prior to the scheduled closing date.

(5) Stipulation Section 7.B. regarding financial reporting was added as an entirely new (additional) provision. This Section establishes a requirement for a future audit by the Public Staff to be commenced on the earlier of (1) six years from the entry of the approval order or (2) the date BHIT's ferry ticket revenues for a quarterly reporting period (12-month period) are 5% greater than or 5% less than the immediately preceding quarterly reporting period. Once such audit is completed, the new provision requires the Public Staff to file a report with the Commission and a recommendation as to whether the Public Staff believes there are grounds for requiring BHIT to show cause why its rates should not be increased or decreased for service rendered thereafter.

(6) Some clarifying language regarding the tram service was added to Tracked Tariff NCUC No. 6 and certain admissibility language originally included in Section 10.B was excluded.

(7) As a result of the Stipulation, rates were reduced below previously stipulated rates for some customer classes and other rates remained unchanged from the previously stipulated rates; and the stipulated rates were lower than what the Company had initially requested as indicated in the following table:

Type of Passenger[1]	Initially Requested Rates	9/30/2010 Stipulated Rates	10/21/2010 Stipulated Rates
1. Class I General	$ 28.00	$ 23.00	$ 23.00
2. Class II Bulk 40	$ 22.00	$ 19.65	$ 17.50
3. Class III Bulk 80	$ 18.00	$ 17.50	$ 15.00
4. Class VI No Frills	$ 18.00	$ 17.00	$ 14.00
5. Class VII Contractor	$ 16.00	$ 14.00	$ 14.00
6. Class IX Employee	$ 16.00	$ 14.00	$ 14.00
7. Class X Children	$ 15.00	$ 14.00	$ 12.00
8. Class XI Annual Pass	$2,800.00	$2,100.00	$1,850.00

[1] The "Class" roman numerals are provided prior to the renumbering of rate classes and eliminated classes are not presented in the table.

9. Class XIII Excess Baggage	$ 28.00	$ 23.00	$ 23.00
10. Class XV Lost/One-Way Ticket	$ 14.00	$ 11.50	$ 11.50

These findings and conclusions are not contested by any party.

EVIDENCE IN SUPPORT OF FINDINGS OF FACT
AND CONCLUSIONS NOS. 7 AND 8

The evidence supporting these findings of fact and conclusions is contained in the verified general rate case application, BHIT's direct and rebuttal testimony and exhibits, the testimony and exhibits of Dr. Julius A. Wright, the testimony, exhibits, and revised exhibits of James G. Hoard, the Stipulation, and the entire record in this proceeding. Public Staff witness Hoard testified concerning certain adjustments reflected in the Stipulation, including the following:

a. An adjustment that reduces the revenue requirement by $73,683 for the gain on the transfer of the former ferry terminal located at Indigo Plantation from utility to nonutility property. Prior to June 2, 2009, BHIT conducted its ferry operations from facilities located at Indigo Plantation. Hoard Exhibit 1, Schedule 3-1, presented the computation of the gain amount and an adjustment that amortizes the gain over a five-year period.

b. An adjustment to include the Bald Head Island terminal in rate base at its depreciated net book value of $363,503, as computed on Hoard Exhibit 1, Schedule 2-2. The impact of including the terminal in rate base at the rate of return reflected in the Stipulation, in lieu of including the lease payment as an operating expense as originally proposed by BHIT, resulted in a reduction in revenue requirement of $278,438.

c. An adjustment to increase operating expenses by $213,338 to reflect the annual impact of reformulating the lease of the Deep Point terminal as a levelized cost-based lease for the BHIT portion of the facility. The computation of the levelized payment was presented on Hoard Exhibit 4.

d. An adjustment to reflect the cost of debt to BHIT at 6.65%. The combination of this cost of debt with the stipulated imputed capital structure composed of 50% long-term debt and 50% member's equity, and a return on equity (ROE) of 10% produces an overall rate of return of 8.33% and a pretax interest coverage ratio of 3.4 times.

These findings and conclusions are not contested by any party.

The following schedules summarize the gross revenues and the rate of return that the Company should have a reasonable opportunity to achieve based upon the determinations made herein. These schedules, illustrating the Company's gross revenue requirement incorporate the findings and conclusions made by the Commission in this Order. As reflected in Schedule I, and as impacted by the other findings in this Order, BHIT is authorized to increase its annual level of ferry ticket revenues by $1,721,928 based upon the updated test year level of operations:

SCHEDULE I
BALD HEAD ISLAND TRANSPORTATION, INC.
North Carolina Operations
Docket No. A-41, Sub 7
STATEMENT OF OPERATING INCOME
Twelve Months Ended December 31, 2009
(000s Omitted)

Item	Present Rates	Approved Increase	Approved Rates
Operating revenues:			
Ferry tickets	$3,372,236	$1,721,928	$5,094,164
Other operating revenues	872,344*	-	872,344
Total operating revenues	$4,244,579~	$1,721,928	$5,966,508
Operating revenue deductions:			
Operations and maintenance	5,014,442	-	5,014,442
Depreciation	315,314	-	315,314
Property taxes	41,214	-	41,214
Payroll taxes	140,622	-	140,622
Regulatory fee	4,049	2,066	6,115
State income tax	0	21,920	21,920
Federal income tax	0	98,598	98,598
Total operating revenue deductions	$5,515,640~	$ 122,585~	$5,638,225
Net Operating Income	($1,271,061)	$1,599,344~	$ 328,283

Notes:

* Other operating revenues is composed of the following:

Item	Amount
Intercompany tram	$100,545
Other tram	4,615
Parking revenues	523,097
Gain on transfer of Indigo Plantation	73,683
Other miscellaneous	170,404
Total other operating revenues	$872,344

~ Denotes rounding per Stipulation.

SCHEDULE II
BALD HEAD ISLAND TRANSPORTATION, INC.
North Carolina Operations
Docket No. A-41, Sub 7
STATEMENT OF RATE BASE AND RATE OF RETURN
Twelve Months Ended December 31, 2009
(000s Omitted)

Item	Amount
Plant in service	$6,656,972
Accumulated depreciation	(2,402,645)
Net plant in service	4,254,326~
Cash working capital	626,805
Average tax accruals	(44,044)
Deferred income taxes	893,752)
Original Cost Rate Base	$3,943,335
Overall Rate of Return on Rate Base:	
Present rates	(32.23%)
Approved rates	8.33%

Note: ~ Denotes rounding per Stipulation.

SCHEDULE III
BALD HEAD ISLAND TRANSPORTATION, INC.
North Carolina Operations
Docket No. A-41, Sub 7
STATEMENT OF RATE BASE AND RATE OF RETURN
Twelve Months Ended December 31, 2009
(000s Omitted)

Present Rates – Original Cost Rate Base

Item	Capitalization Ratio	Original Cost Rate Base	Embedded Cost or ROE	Net Operating Income
Long-term debt	50.00%	$1,971,668	6.65%	$ 131,116
Member's equity	50.00%	1,971,668	(71.12%)	(1,402,177)
Total	100.00%	$3,943,335~		($1,271,061)

Approved Rates – Original Cost Rate Base

Item	Capitalization Ratio	Original Cost Rate Base	Embedded Cost or ROE	Net Operating Income
Long-term debt	50.00%	$1,971,668	6.65%	$ 131,116
Member's equity	50.00%	1,971,668	10.00%	197,167
Total	100.00%	$3,943,335~		$ 328,283

Note: ~ Denotes rounding per Stipulation.

EVIDENCE IN SUPPORT OF FINDING OF FACT AND CONCLUSION NO. 9

The evidence supporting this finding of fact and conclusion is contained in the verified general rate case application, BHIT's direct and rebuttal testimony and exhibits, the testimony and exhibits of Dr. Julius A. Wright, the testimony, exhibits, and revised exhibits of James G. Hoard, the Stipulation, and the entire record in this proceeding.

Public Staff witness Hoard testified that the parking revenue adjustment of $523,097 reflects a compromise that considers projected operating results of the parking facility over a period of years. He testified that neither the investment nor the operating expenses associated with the Deep Point parking facilities are reflected in the revenue requirement computation on a fully rolled-in basis, and thus the entire amount of the parking revenue adjustment results in a direct reduction in the amount of the rate increase. Further, witness Hoard explained that had the parking facility been reflected in revenue requirement on a fully rolled-in basis, the full amount of parking revenues would have been offset by the pretax rate of return on the parking facility rate base investment, depreciation expense, operation and maintenance expenses, property taxes, and payroll taxes. Witness Hoard opined that the revenue requirement impact of reflecting the parking facility on a fully rolled-in basis would have been considerably less favorable for ratepayers than the stipulated adjustment. This finding and conclusion is not contested by any party.

EVIDENCE IN SUPPORT OF FINDINGS OF FACT
AND CONCLUSIONS NOS. 10 THROUGH 13

The evidence supporting these findings of fact and conclusions is contained in the verified general rate case application, BHIT's direct and rebuttal testimony and exhibits, the testimony and exhibits of Dr. Julius A. Wright, the testimony, exhibits, and revised exhibits of James G. Hoard, the Stipulation, the Joint Proposed Order, and the entire record in this proceeding. These findings and conclusions are not contested by any party.

EVIDENCE IN SUPPORT OF FINDINGS OF FACT
AND CONCLUSIONS NOS. 14 THROUGH 19

The evidence supporting these findings of fact and conclusions is contained in the verified general rate case application, BHIT's direct and rebuttal testimony and exhibits, the testimony and exhibits of Dr. Julius A. Wright, the testimony, exhibits, and revised exhibits of James G. Hoard, the Stipulation, and the entire record in this proceeding. These findings and conclusions are not contested by any party.

EVIDENCE IN SUPPORT OF FINDING OF FACT AND CONCLUSION NO. 20

The evidence supporting this finding of fact and conclusion is contained in the verified general rate case application, BHIT's direct and rebuttal testimony and exhibits, the testimony, exhibits, and revised exhibits of James G. Hoard, the Stipulation, and the entire record in this proceeding. This finding and conclusion is not contested by any party.

FERRIES – RATE INCREASE

EVIDENCE IN SUPPORT OF FINDING OF FACT AND CONCLUSION NO. 21

The evidence supporting this finding of fact and conclusion is contained in the verified general rate case application, BHIT's direct and rebuttal testimony and exhibits, the testimony and exhibits of Dr. Julius A. Wright, the testimony, exhibits, and revised exhibits of James G. Hoard, the Stipulation, and the entire record in this proceeding. This finding and conclusion is not contested by any party.

Customer emails were received between October 28, 2010 and November 15, 2010, wherein such customers expressed, among other things, that the stipulated rate increase was unfair and unreasonable and that the Commission should reject the Stipulation and proceed to a further hearing and final ruling on all issues. The Commission has reviewed such correspondence and appreciates all the customer participation in this matter. The Commission acknowledges that there has been significant involvement by consumer interests in this proceeding which has greatly influenced the outcome of this rate case. In particular, the three Customer Group Intervenors - BHA, the Club, and the Village - played a very active and important role in asserting the interests of the specific consumer groups they represented; and they endeavored to support their recommendations through the submission of expert testimony. The Commission believes that the Customer Group Intervenors represented the vast majority of the consumers that will ultimately be affected by the final determinations made in this proceeding.

Furthermore, according to information provided in their respective petitions to intervene - BHA is a NC non-profit corporation, organized for the purposes of providing for beautification, maintenance, and architectural control of the exterior of homes and common areas of Stage 1 of BHI, to promote the health, safety, and welfare of the residents and act as an advocate for approximately 1,200 property owners; the Club is a NC non-profit corporation, organized for social and recreational purposes on BHI and its facilities include restaurants, a golf course, tennis courts, a swimming pool, and other sports and social facilities; and the Village is a municipal corporation, governed by an elected Village Council which exits, in part, to help property owners maintain the Island's unique qualities and to ensure that the Island is an accessible and enjoyable place to live, visit, and work. Further, the Public Staff, an independent agency from the Commission that represents the using and consuming public in all Commission proceedings affecting rates or service, was also very actively involved in the ultimate resolution of the issues in this proceeding.

The Commission believes that the compromises and ultimate settlement that was reached in this proceeding fairly acknowledged the interests represented by the various consumer groups in large measure. Unfortunately, it is not unusual for some affected consumers to be partially or completely dissatisfied with the final resolution of various opposing issues in a general rate case proceeding. However, the Commission is of the opinion that, in light of the various provisions set forth in the Stipulation that were agreed upon by the opposing parties, particularly those provisions such as the imputation of the revenues related to the Deep Point parking facilities (Stipulation Section 2.C.i.) and the limitations and the terms of such limitations agreed to by BHIL regarding price increases with respect to seasonal/non-seasonal daily parking rates and annual parking (Stipulation Section 2.C.i.a. and Section 2.C.i.b.), that opening up the hearing to obtain further evidence for review and consideration would not be productive or beneficial in this proceeding. Additionally, the Commission finds and concludes that the agreed-upon quarterly financial reporting (Stipulation Section 7.A.) as well as the future Public Staff audit (Stipulation Section 7.B.) should effectively apprise the Commission in a timely manner of any rate issues regarding the operations of BHIT that may need to be further investigated in the future.

The Commission has carefully reviewed the Stipulation and Stipulation Exhibits. The revenue requirement and allocation, accounting treatment, and other issues addressed and resolved in the Stipulation are the result of negotiations among the parties to this proceeding and are not opposed by any party. The Commission finds and concludes that the Stipulation provides a just and reasonable resolution of all of the issues necessary to be addressed in this proceeding and that its adoption will result in rates that are just and reasonable to all customer classes in consideration of all of the evidence presented in this proceeding.

IT IS, THEREFORE, ORDERED as follows:

1. That the Stipulation is hereby received into evidence in this proceeding and is approved in its entirety. The provisions of the Stipulation are incorporated herein by reference as if set out in full in this Order. Pursuant to Section 12 of the Stipulation regarding the receipt of testimony, the prefiled direct and rebuttal testimony and exhibits of Shirley A. Mayfield, Frederick W. Hering, and James W. Fulton, Jr., the prefiled direct testimony and exhibits of James G. Hoard and Dr. Julius A. Wright, and the amended joint rebuttal testimony and exhibits of Company witnesses Mayfield and Hering are received into evidence in this proceeding. Further, the Commission receives into evidence the Stipulation Exhibits and the late-filed revised exhibits of Public Staff witness Hoard.

2. That the Schedule of Rates and Charges (Tariff NCUC No. 6) attached as Exhibit D to the Stipulation with an effective date of January 1, 2011, shall be, and hereby is approved. In addition, the following provisions regarding ticket renewal and expiration dates of current tickets held by customers are approved:

a. Currently issued Class XI Annual Passes sold at the current rate will continue to be honored for passage until they expire, but no Class XI Annual Passes sold or renewed at the current rate will be honored after December 31, 2011. Annual passes held by agencies or nonresidential property owners that expire after December 31, 2010, will not be renewed. There shall be no proration in value of either a currently issued annual pass or new/renewed annual pass.

b. Currently issued Class XII Senior Citizen Annual Passes will continue to be honored for passage until they expire, but shall not be renewed upon expiration after December 31, 2010. No Class XII Senior Citizen Annual Passes sold or renewed at the current rate will be honored after December 31, 2011. There shall be no proration in value of either a currently issued annual pass or new/renewed annual pass.

c. All other tickets (except Class II Bulk-Fare, Class XV Lost Tickets, and Class VI No Frills tickets) shall be honored when used and/or may be presented for refund or credit towards purchase of another ticket through March 31, 2011, but shall expire and have no value after that date. Class II Bulk Fare tickets issued on or before December 31, 2010, will be honored for passage only when used though March 31, 2011, but will be accepted for refund or credit towards purchase of other ticket(s) when presented or returned at any time up to and including June 30, 2011, and will have no value after that date.

3. That prior to implementing Tariff NCUC No. 6, BHIT shall provide the Public Staff's Transportation Rates Division with its revised tariff sheets, incorporating the increased rates and ferry operation changes approved herein. Further, upon review and acceptance by the Public Staff, that the increased rates and ferry operation changes approved herein have been properly reflected in the Company's revised tariff, BHIT shall file with the Commission a copy of its new Tariff NCUC No. 6.

4. That within 30 days of the date of this Order, BHIT shall file with the Commission all amendments to BHIT's affiliate agreements with BHIL that reflect any changes necessary to conform the affiliate agreements with this Order.

5. That BHIT (and BHIL, as applicable,) shall comply with the Stipulation, including the provision that BHIT shall file with the Commission the quarterly financial reports described in Finding of Fact and Conclusion No. 17.

6. That, not later than Friday, December 31, 2010, BHIT shall, at its own expense, publish in newspapers having general coverage in its service area, the Notice to Customers attached hereto as Appendix A, once a week for two consecutive weeks. The Notice shall cover no less than one-fourth of a page. In addition, within 10 days after the date of this Order and until January 30, 2011, BHIT shall post a copy of the Notice to Customers at the Deep Point and Bald Head Island ferry terminals.

7. That, BHIT shall file no later than Monday, January 17, 2011, an affidavit of publication and a certificate of service showing that it provided notice as required herein.

ISSUED BY ORDER OF THE COMMISSION.
This the 17th day of December, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

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STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. A-41, SUB 7

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Bald Head Island Transportation, Inc. for a General Increase in its Rates and Charges Applicable to Ferry Service Between Southport, North Carolina and Bald Head Island, North Carolina	) NOTICE TO CUSTOMERS) OF RATE INCREASE) EFFECTIVE) JANUARY 1, 2011)

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission (Commission) issued an Order on December 17, 2010, authorizing Bald Head Island Transportation, Inc. (BHIT), to increase and adjust its rates and rate design for ferry transportation service to and from Southport, North Carolina and Bald Head Island, North Carolina, effective on January 1, 2011, as explained below.

Pursuant to the Commission's Order, there are certain changes in rate design, classifications, fares, and tariffs for the ferry transportation service. The number of classes of tickets will be reduced from 15 to 10, eliminating six of the current classes and adding one new class. The classes that will be eliminated will be Class III Group Purchases; Class IV Government Employees; Class V Special Event; Class VIII Corporate Guest; Class XII Senior Citizen Annual Pass; and Class XIV Student Ticket. A new Bulk 80 ticket class will be created. The following table presents the rate changes and the classes that will be eliminated and created effective January 1, 2011:

Type of Passenger	Current Rate*	Approved Rate
General	$16.00	$23.00
Bulk 40	$13.50	$17.50
Bulk 80	N/A	$15.00
No Frills	$11.00	$14.00
Contractor	$11.00	$14.00
Employee	$9.00	$14.00
Children, ages 3-12	$9.00	$12.00
Annual Pass	$1,665.00	$1,850.00
Excess Baggage	$15.00	$23.00
One-Way	$5.00	$11.50

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Eliminated Classes	Eliminated Rates
Group Purchases	$13.50
Government Employees	$10.00
Special Event	$11.00
Corporate Guest	$ 9.00
Senior Citizen Annual Pass	$842.00
Student Ticket	$5.00

General - Available to all persons traveling to Bald Head Island (BHI) from Southport who do not qualify for any other fare.

Bulk 40 - Available to persons or organizations who purchase packages of 40 ferry tickets at one time.

Bulk 80 - Available to persons or organizations who purchase packages of 80 tickets at one time. The Bulk 80 ticket will be issued via a durable plastic, photo ID bar-coded ticket, specific to each customer, valid for 80 round trips. No tram service is provided.

No Frills - Round trip tickets available for purchase only on BHI by persons living or staying on BHI and valid only on day of purchase. No baggage service or tram service available with this ticket and hand-held parcels only.

Contractor - Available to bona fide contractors traveling to BHI to provide service. Not available on Saturday or Sunday. Contractor ferry must be used unless otherwise noted. Shuttle bus only is included. No baggage handling or tram services are included.

Employee - Available to employees of governments, governmental agencies, commercial, and non-profit businesses on BHI who are traveling in the course of their employment. Allowed to board after all other fares have boarded. No tram or baggage included.

Children - For ages 3-12 traveling with an adult. No charge for children under age 3.

Annual Pass - Available only to persons whose primary residence is on BHI who are residential property owners of record or persons leasing residential property. Tram service is not included.

Excess Baggage - Applicable to each bicycle or other non-carry-on item deemed too large to fit into baggage containers.

One-Way - Available only on BHI to persons who cannot present a valid ticket for passage on the second leg of their round trip under any fare described above except No Frills.

*The current rate includes a $1.00 fuel surcharge previously approved by Order of the Commission in Docket No. A-41, Sub 5, on December 16, 2008. The approved rate does not include a fuel surcharge.

On and after January 1, 2011, currently issued Class XI Annual Passes sold at the current rate will continue to be honored for passage until they expire, but no Class XI Annual Passes sold or renewed at the current rate will be honored after December 31, 2011. Annual passes held by agencies or nonresidential property owners and that expire after December 31, 2010, will not be renewed. In addition, currently issued Class XII Senior Citizen Annual Passes will continue to be honored for passage until they expire, but shall not be renewed upon expiration, if such pass expires after December 31, 2010. No Class XII Senior Citizen Annual Passes sold or renewed at the current rate will be honored after December 31, 2011. All other tickets (except Class II Bulk Fare, Class XV Lost Tickets, and Class VI No Frills tickets) shall be honored when used and/or may be presented for refund or credit towards purchase of

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another ticket through March 31, 2011, but shall expire and have no value after that date. Class II Bulk Fare tickets issued on or before December 31, 2010, will be honored for passage only when used though March 31, 2011, but will be accepted for refund or credit towards purchase of other ticket(s) when presented or returned at any time up to and including June 30, 2011, and will have no value after that date. Refunds or credits are allowed only upon presentation of the two-part round trip ticket. A single part will not be refunded or credited. There shall be no proration in value of either a currently issued annual pass or new/renewed annual pass.

A complete copy of the Commission's Order authorizing these new rates and approving this rate design can be obtained from the offices of BHIT or may be viewed and printed from the Commission's website at www.ncuc.net. Click on "Docket Search" and type in the docket (A-41) and sub (7) numbers. Detailed ferry information including hours of operation may be viewed at www.ferrytobhi.com or www.baldheadisland.com/contact/ferry_information.aspx.

This the 17th day of December, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

NATURAL GAS – ADJUSTMENT OF RATES/CHARGES

DOCKET NO. G-5, SUB 516

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 10, 2010, at 10:00 a.m., in Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner William T. Culpepper, III, Presiding; Commissioners Bryan E. Beatty and Susan W. Rabon

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

Margaret A. Force, Assistant Attorney General, P.O. Box 629, Raleigh, North Carolina 27602

BY THE COMMISSION: On June 1, 2010, 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; Terina H. Cronin, General Manager, Gas Supply & Commercial and Industrial Marketing; and Rose M. Jackson, General Manager, Supply & Asset Management, in connection with the annual review of PSNC's gas costs for the twelve-month period ended March 31, 2010.

On June 4, 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, August 10, 2010, set prefiled testimony dates, and required the Company to give notice to its customers of the hearing on this matter.

On June 25, 2010, the Attorney General filed a Notice of Intervention. On June 29, 2010, Carolina Utility Customers Association, Inc., filed a Petition to Intervene, which was granted by the Commission on July 2, 2010.

On July 26, 2010, the Public Staff filed the direct testimony and exhibits of Catherine L. Eastwood, Staff Accountant, Accounting Division; Jan A. Larsen, Public Utilities Engineer, Natural Gas Division; and James G. Hoard, Assistant Director, Accounting Division.

No other party filed testimony.

On August 10, 2010, the matter came before the Commission for hearing 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 October 1, 2010, the Public Staff and PSNC filed late-filed exhibits and comments addressing Commission Hoard Examination Exhibit 1, and the Public Staff also filed a late-filed exhibit that provided the effect of the proposed temporary increments on a typical residential customer.

On October 25, 2010, the Commission issued a Notice of Decision and Order. The Notice of Decision and Order gave notice that the Commission had made a decision and would publish an order approving PSNC's accounting for gas costs for the review period, finding that the gas costs incurred by PSNC during the review period were reasonably and prudently incurred, and authorizing PSNC to recover 100% of those gas costs. The Notice of Decision and Order further ordered PSNC to make an entry in its All Customers Deferred Account to reflect the ($93,464) credit, plus interest, related to emergency gas services that PSNC billed customers during the review period and further ordered PSNC to credit any future emergency gas surcharges it bills to customers to its deferred accounts. It also ordered PSNC to remove the existing temporary rate increments that were implemented in Docket No. G-5, Sub 509, and to implement temporary rate increments shown in Public Staff witness Larsen Exhibit 1, effective for service rendered on and after November 1, 2010. Finally, it ordered PSNC to give notice to its customers of the rate changes allowed in the Notice of Decision and Order.

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 476,000 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, 2010.

5. During the period of review, PSNC incurred total gas costs of $291,736,293, which was composed of demand and storage charges of $67,536,651, commodity gas costs of $253,273,057, and other gas costs of ($29,073,415).

6. In compliance with the Commission's order in Docket No. G-100, Sub 67, the Company credited 75% of the net compensation from secondary market transactions, which amounted to $9,470,012, to its All Customers Deferred Account.

7. At March 31, 2010, the Company had a debit balance of $8,125,701 in its Sales Customers Only Deferred Account and a debit balance of $1,692,330 in its All Customers Deferred Account.

8. The All Customers Deferred Account balance at March 31, 2010, reflects an adjustment of ($93,464) for emergency gas services PSNC billed its customers during the review period. It is appropriate that PSNC credit any future emergency gas surcharges it bills to customers to its deferred accounts.

9. The Company has properly accounted for its gas costs incurred during the review period.

10. PSNC's hedging activities during the review period were reasonable and prudent.

11. As of March 31, 2010, the Company had a debit balance of $7,862,407 in its Hedging Deferred Account.

12. It is appropriate to transfer the $7,862,407 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 debit balance of $15,988,108.

13. 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.

14. PSNC has a portfolio of long-term and supplemental short-term supply agreements with a variety of suppliers, including producers and independent marketers.

15. The gas costs incurred by PSNC during the review period were prudently incurred.

16. As a result of this proceeding, the Company should implement the temporary increments proposed by Company witness Paton and by Public Staff witness Larsen.

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 data, 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, 2010.

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 witness Paton and Public Staff witness Eastwood.

PSNC witness Paton's exhibits reflect demand and storage costs of $67,536,651, commodity costs of $253,273,057, and other gas costs of ($29,073,415) for a total of $291,736,293. Public Staff witness Eastwood agreed that total gas costs for the review period ended March 31, 2010, were $291,736,293. Witness Eastwood further testified that PSNC properly accounted for its gas costs during the review period. Witness Eastwood stated that the Company earned $12,626,684 of margin on secondary market transactions, including capacity release transactions and storage management arrangements, during the review period. Of this amount, $9,470,012 (75% of $12,626,684) was credited to the All Customers Deferred Account for the benefit of ratepayers pursuant to the Commission's December 22, 1995 Order Approving Stipulation in Docket No. G-100, Sub 67, which authorizes an LDC to retain 25% of the net compensation from secondary market transactions and requires that 75% be credited to the LDC's All Customers Deferred Account.

Witness Eastwood testified that in PSNC's Annual Review of Gas Costs in Docket No. G-5, Sub 509, the Public Staff stated that it would continue to monitor the uncollectible gas cost entries recorded in the deferred account. Company witness Paton testified that the only issue that affected uncollectible gas arose when the rate tables used to calculate deferred uncollectible gas costs were not updated for the benchmark decrease in January 2009, which thus reflected two effective rates. The error slightly understated the amount of uncollectible gas costs. Since this was a benefit to customers, PSNC decided not to make any correcting entries to the uncollectible gas cost entries. Public Staff witness Eastwood testified that the issue was thoroughly reviewed by the Pubic Staff and was determined to have no material impact on the deferred uncollectible cost of gas entries. Witness Eastwood further testified that the Public Staff will continue to closely monitor and review the uncollectible gas cost entries recorded in the deferred account.

Public Staff witness Eastwood stated that she had adjusted the All Customers Deferred Account to reflect a ($93,464) credit related to emergency gas services that PSNC billed customers during the review period. Witness Eastwood testified that emergency gas service is a service that PSNC has the discretion to provide after a curtailment notice has been provided to the customer. Witness Eastwood testified that PSNC agreed to the adjustment and also agreed to credit any future emergency gas surcharges it bills to customers to its deferred accounts.

Witness Eastwood testified that, based on her review of the gas costs in this proceeding, the appropriate deferred account balance as of March 31, 2010, for the Sales Customers Only Deferred Account is a debit balance of $8,125,701. Witness Eastwood also stated that the adjusted balance in the All Customers Deferred Account as of March 31, 2010, is a debit balance of $1,692,230.

The Commission concludes that the appropriate balances of the Company's deferred accounts as of March 31, 2010, are a debit balance of $8,125,701 in its Sales Customers Only Deferred Account and a debit balance of $1,692,330 in its All Customers Deferred Account. The Commission further concludes that PSNC has properly accounted for its gas costs during the review period.

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

The evidence for these findings of fact is contained in the testimony of PSNC witnesses Paton and Cronin and Public Staff witness Hoard.

PSNC witness Paton testified that during the review period the Company incurred net costs of $7,862,407 in its Hedging Deferred Account. Public Staff witness Hoard testified that these costs were composed of: Economic Losses - Closed Positions of $2,488,420; Premiums Paid - Closed Positions of $4,860,720; Premiums Paid - Open Positions of $253,620; Brokerage Fees and Commissions of $3,957; Interest on the Brokerage Account of $569; and Interest on the Hedging Deferred Account of $255,121. Witness Hoard testified that most of the Economic Loss - Closed Positions amount related to Over-the-Counter (OTC) swaps for the months of July through October 2009, that PSNC had entered into during November 2007 through March 2008. Witness Hoard further testified that the OTC swap contracts' fixed prices represented reasonable values at the time of the transactions.

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 to mitigate the impact of unexpected or adverse price fluctuations to its customers at a reasonable cost.

Witness Cronin stated that while the goals of mitigating price volatility and protecting against sharp increases in price have not changed over the years, changes to the hedging program in 2008 made protecting against sharp rises in price a higher priority than in the past. The main thrust of these changes was to place greater emphasis on the use of call options in order to help control costs while still providing protection from higher prices.

Witness Cronin testified that, by using call options, the maximum hedging loss is limited to the amount of the premium paid for the call option, similar to the cost of homeowner's insurance being limited to the premium paid for the insurance. Another way in which call options are similar to insurance is that the owner of the insurance policy receives payment only if the event insured against occurs; in the example of call options, this would be the price rising above the stated strike price on the option.

She testified that PSNC took an additional step in 2008 to control hedging costs by limiting the cost of the call options purchased to no more than 10% of the underlying commodity price. For example, if the month being hedged is currently trading at $6.00, the maximum premium paid would be $0.60. The tradeoff for this cost control, she testified, is the potential of raising the strike price above the current market price. In the example of a $6.00 market, the strike purchased might end up being $6.50 in order to limit up front cost to $0.60. Even though the higher strike is less desirable, the up-front savings are significant and are an important part of PSNC's strategy to provide protection at a reasonable cost.

Witness Cronin testified that another advantage of using call options is that they allow the owner to benefit if prices decline, lessened only by the premium paid for the call. As long as prices remain moderate, a result of this shift toward call options is that many of these options will expire unexercised; PSNC's price will float with the market and volatility will be reduced only if prices settle above the hedged strike prices. Therefore, compared to the past, the current hedging program places a greater emphasis on controlling sudden spikes in prices and less on volatility reduction. This emphasis results in a reduction in hedging costs over time.

Witness Cronin testified that, in contrast, a strategy more heavily weighted toward fixed price hedging instruments such as futures will do a better job at volatility reduction; however, some of the volatility reduced is associated with lower prices and the owner of this type of hedge no longer benefits from prices falling. Using fixed price instruments does have the advantage of no up-front costs but it does not limit the amount of possible loss on the hedge resulting from falling prices. While fixed price hedges are still allowed under PSNC's hedging program, their use has been limited to select situations and requires additional approval from management. This gives PSNC the flexibility to take advantage of certain situations while still keeping the focus on avoiding spikes in prices and cost control.

She testified that one final change made to PSNC's hedging program in 2008 limited to 12 months the time period of future months in which to hedge. This allows PSNC to obtain more favorable option pricing terms and to better react to changing market conditions.

Witness Cronin elaborated that, as has been the case for some time, financial hedges are limited to 25% of PSNC's annually estimated sales volume. 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.

Witness Cronin emphasized that in addition to utilizing financial instruments to mitigate price volatility and protect against sudden price increases, PSNC continues to utilize the flexibility available within its storage, supply, and capacity contracts to purchase, store, and dispatch gas in a cost-effective manner. Also, the use of deferred gas cost accounting to calculate the Company's benchmark cost of gas provides a smoothing effect on gas price 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 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 Hoard concluded that PSNC's hedging activities were reasonable and prudent and that the ending net debit balance of $7,862,407 should be transferred to the Sales Customers Only Deferred Account.

Witness Hoard testified that, since PSNC began hedging in January 2003, it had experienced mixed results in its hedging performance from a gain and loss perspective. In some years, it had experienced gains and in other years it had experienced losses. Witness Hoard testified that, over the eight-year period since it began hedging, PSNC had paid $21.6 million in premiums and incurred economic losses of $24.2 million, and that these hedging costs represented approximately 2% of its gas supply costs, or $0.14 per dekatherm. Witness Hoard concluded that PSNC's decision to hedge its gas costs was consistent with the Commission's conclusions regarding the hedging option, as set forth in the February 26, 2002 Order on Hedging in Docket No. G-100, Sub 84 (Hedging Order).

One particular area of interest to the Commission in this proceeding is to determine what the Company has done to meet the goals espoused in the Hedging Order. Furthermore, the Commission has noted significant differences between the hedging programs of North Carolina's two large LDCs. In its October 28, 2009 Order on Annual Review of Gas Costs in Docket No. G-5, Sub 509 (the 2009 ARGC Order), the Commission sought more information in this docket as follows:

> The Commission's February 26, 2002 Order on Hedging in Docket No. G-100, Sub 84 made clear that each LDC should tailor a hedging program for the needs of its customers. That Order also made clear that the general goal of hedging is to reduce commodity price volatility. However, the existence of substantial variations between the hedging programs of the two large LDCs raises questions. It would be helpful for the Commission to see a more rigorous explanation of the specific goals that come out of each company's analysis and how each company's hedging program is designed to meet those goals. It is possible that both the LDCs and the Commission could learn from such explanations.

To that end, Ordering Paragraph 3 of the Commission's 2009 ARGC Order ordered PSNC, in this docket, 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 response to Ordering Paragraph 3 of the 2009 ARGC Order, PSNC witness Cronin testified as follows:

> 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. 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 to mitigate the impact of unexpected or adverse price fluctuations to our customers at a reasonable cost.

Witness Cronin further testified that while the goals of mitigating price volatility and protecting against sharp increases in price have not changed, in 2008, three changes were made in the PSNC hedging program that placed a higher priority on protecting against sharp rises than in the past. PSNC decided (1) to place greater emphasis on the use of call options, (2) to limit cost of the call options purchased to no more than 10% of the underlying commodity price, and (3) to limit to 12 months the time period of future months in which it would hedge. Witness Cronin explained that call options provide up-front savings compared to fixed-price hedging instruments and allow the owner to benefit if prices decline. She stated that limiting the cost to no more than 10% of the underlying commodity price provided cost control, and while "the tradeoff for this cost control is the potential of raising the strike price above the current market price," the measure provides significant savings. She asserted that limiting the hedging time horizon to 12 months "allows PSNC to obtain more favorable option pricing terms and to better react to changing market conditions."

Commission Hoard Examination Exhibit 1 was received into evidence at the hearing. That exhibit compared the actual gas prices paid by customers of PSNC for the gas supply component of rates to the physical spot price of natural gas. At the close of the hearing, parties were invited to file post-hearing comments on the exhibit and provide an exhibit in better form if deemed appropriate. PSNC and the Public Staff filed comments and late-filed exhibits in response.

PSNC provided, along with its comments, an alternative analysis in its late-filed exhibits to measure the effect of its hedging program, along with other tools, in mitigating the volatility in the price its sales customers paid for all natural gas purchased by PSNC. PSNC measured volatility using standard deviation of five data sets: NYMEX settle prices, all index and spot purchases made by PSNC, index and spot purchases adjusted for storage injections and withdrawals, index and spot purchases adjusted both for storage and hedging transactions, and PSNC's benchmark including increments and decrements (the price sales customers actually paid). PSNC concluded from this analysis that PSNC's hedging program has met its objective of mitigating price volatility.

The Public Staff also provided comments and Late-Filed Exhibit No. 1. The Public Staff stated that its exhibit shows that PSNC has avoided rate shock to customers by periodically adjusting the price paid by customers for gas supply while not passing through to customers the full impact of the changes in its gas supply costs. The Public Staff described how PSNC uses its storage services and facilities, management of its benchmark, and hedging to meet this goal. The Public Staff concluded that the prices PSNC charges customers for gas supply have struck a reasonable balance between maintaining the price signals of changing market conditions while avoiding rate shock to customers.

The Commission finds and concludes that PSNC's hedging activities during the review period were reasonable and prudent and that its hedging net debits of $7,862,407 incurred during the review period should be transferred to the Company's Sales Customers Only Deferred Account. The Commission concludes that, subsequent to the transfer, the Sales Customers Only Deferred Account has a net debit balance of $15,988,108.

The Commission notes that PSNC has demonstrated a commendable level of competence in the technical aspects of using financial derivatives to hedge commodity prices, as shown in witness Cronin's testimony in this docket. PSNC has also worked to minimize hedging costs. However, the Commission perceives an apparent heavy dependence on models based on historical statistics in the hedging program, which raises questions. In the 2009 ARGC Order, it was noted that "witness Cronin testified that PSNC has people looking at the models and monitoring the market on a daily basis. These individuals look at the results of the model and the market and then decide whether to proceed with or deviate from the model." In the Order in Docket No. G-100, Sub 84, the Commission assured LDCs that it will evaluate the prudency of their hedging decisions 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. The Commission is now interested in learning more about the information, other than the guidance from the models themselves, that PSNC uses in making its hedging decisions and about when and how PSNC deviates from the results of its models. The Commission is particularly interested in learning whether PSNC uses forward-looking market projections by accepted experts in the natural gas field and, if it does, how such projections are used.

To that end, the Commission directs PSNC to file testimony in its next annual review proceeding addressing the information, other than the models, that it uses in its hedging program and addressing how it has or will deviate from the guidance provided by its models. The Commission is not focused on PSNC's day-to-day decisions. Also, the Commission does not expect PSNC to out-guess the market. The Commission further recognizes that discipline is a part of any hedging program, and it is usually appropriate in a hedging program to obtain some level of price insurance regardless of broad market trend. The Commission is interested, however, in what PSNC does, other than acting on the information generated by its models, in making its hedging decisions and how PSNC analyzes and reacts to projections and broad market trends.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 13 - 15

The evidence for these findings of fact is found in the testimony of PSNC witnesses Cronin and Jackson and Public Staff witnesses Larsen and Hoard.

PSNC witness Cronin testified that approximately 42% 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 to maintain the necessary supply security for all of the Company's firm customers PSNC has supply contracts with delivery guarantees and storage service contracts with delivery rights that provide total gas deliveries to PSNC and that facilitate the full utilization of PSNC's firm interstate pipeline transportation and storage capacity.

Witness Cronin testified that the Company has long-term supply agreements and supplemental short-term agreements with a variety of suppliers, including producers and independent marketers. She stated that PSNC has increased its security of gas supplies by developing a diversified portfolio of long and short-term suppliers.

Witness Cronin testified that maintaining the necessary operational flexibility in its gas supply portfolio is the second criterion. Flexibility is needed to facilitate PSNC's ability to react to the unpredictable nature of weather and the changing production levels and operating schedules of PSNC's industrial customers, combined with their ability to switch to alternate fuels. She noted that while each of the supply agreements has different purchase commitments and swing capabilities, the gas supply portfolio as a whole must be capable of dealing with the monthly, daily, and hourly changes in the Company's market requirements.

In regard to the third criterion, cost of gas, 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. Witness Cronin further stated that PSNC continues to weigh the relative importance of each factor when developing 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 Pipe Line Corporation (Transco), the only interstate pipeline with which PSNC has a direct connection. The Company also has a backhaul transportation arrangement with Transco to redeliver gas, as well as storage service agreements with Dominion Transmission, Incorporated (DTI); Columbia Gas Transmission Corporation; and East Tennessee Natural Gas Company (ETNG.) In addition, PSNC has storage service agreements with Dominion Cove Point LNG, LP; Saltville Gas Storage Company, LLC (Saltville); and Pine Needle LNG Company, LLC. She noted that PSNC also has upstream firm transportation (FT) agreements with Texas Gas Transmission, LLC and Transco, both of which interconnect with DTI.

Witness Cronin testified that PSNC amended its Eminence Storage Service agreements with Transco to subscribe to increased injection capability. The amendment entered into in May 2009 increased PSNC's storage injection capability from 6,365 dekatherms (dt)/day to 20,793 dt/day at Transco's ESS facility and also extended the contracts' expiration date to 2029. This additional injection capability, which became available in October 2009, provides PSNC with increased flexibility in meeting market demands. She testified that, in anticipation of this increased flexibility, PSNC was able to reduce the quantities as well as the cost of other balancing services.

Additionally, witness Cronin testified that in February 2010, PSNC signed a precedent agreement with Cardinal Pipeline LLC (Cardinal) for 50,000 dt/day of FT service on Cardinal's proposed System Expansion Project. PSNC and Cardinal signed the Firm Transportation Service Agreement in March 2010. This additional transportation service, which is targeted to be available July 2012, will enable PSNC to serve its growing customer demand in the eastern part of PSNC's franchised service territory.

Finally, witness Cronin testified that, in May 2009, PSNC entered into a Joint Venture Agreement for the purpose of acquiring an ownership interest in the capacity of a new transmission pipeline being constructed by the City of Monroe interconnecting with Transco (Monroe Pipeline). Pursuant to an Amendment to Joint Venture Agreement approved by the Commission on May 18, 2010, PSNC will lease 17,250 dt/day of transportation capacity on the Monroe Pipeline, which will enable PSNC to provide reliable service to meet the growing needs of customers in Cabarrus County.

Company witness Cronin further testified that PSNC secures and maintains firm transportation and storage capacity rights to ensure the deliverability of its gas supplies to meet the design day, seasonal, and annual customer needs. During periods of design day conditions, the marketplace has little if any unused capacity available. Pipeline and storage capacity contracts typically require the payment of year round, fixed demand charges to reserve firm transportation or storage entitlements. Therefore, as an alternative, low-cost means to address its peak day requirements, PSNC entered into Curtailment Gas Purchase Agreements with four of its largest shippers. Witness Cronin testified that these agreements give PSNC the right to purchase gas, originally intended for the shipper's customers who have been curtailed, to be delivered by the shipper to PSNC's system on a firm basis.

She further testified that PSNC's FT capacity is supported by a gas supply portfolio of long-term supply contracts with a variety of suppliers, including baseload contracts that provide a fixed volume of gas each day, take-or-release contracts that provide the flexibility to modify the volumes delivered on a monthly basis, and no-notice contracts that provide the flexibility to increase or decrease volumes on a daily basis. According to witness Cronin, PSNC had approximately 215,000 dt/day under term contracts with six producers and three independent marketers as of November 1, 2009, 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 testified to the following activities that PSNC has engaged in to lower gas costs while maintaining security of supply and delivery flexibility:

1. PSNC continues to evaluate various FT and storage capacity options to ensure that future peak day and seasonal durational requirements will be met. As discussed above, PSNC entered into various agreements for transportation and storage capacity to meet growing peak demand on its system.

2. PSNC continues to utilize 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, which permits gas to remain competitive with alternative fuels and allows PSNC to maintain throughput.

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.

Public Staff witness Larsen stated that he had reviewed the testimony and exhibits of the Company witnesses, monthly operating reports, gas supply and pipeline transportation and storage contracts, and the Company's responses to the Public Staff's data requests. Witness Larsen 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, assuming normal growth, it is anticipated that PSNC will need to acquire additional capacity by the 2012-2013 winter season. Upon cross-examination by Commissioner Culpepper, witness Larsen stated that at each annual review of gas costs proceeding, the Public Staff calculates the anticipated peak day demand for the next five years and discusses with the Company how it will be able to meet that demand. Witness Larsen further stated that PSNC is very active in ensuring it has adequate capacity to meet its anticipated demand.

The Commission, in its 2009 ARGC Order, noted that PSNC is a customer of Pine Needle, a FERC-regulated entity, and that an affiliate of PSNC has an equity interest in Pine Needle. The Commission further stated that, as a result of exercising its responsibilities pursuant to G.S. 62-48, it is familiar with Section 5 and Section 4 of the Natural Gas Act (NGA) and their impact on proceedings before the FERC. The Commission stated in the Order that it perceived that the workings of the NGA, a federal statute, potentially favored a FERC-regulated entity in negotiations with its customers and, therefore, benefits a PSNC affiliate as an equity participant in the FERC-regulated entity, but potentially harms PSNC as a customer of the entity.

In Ordering Paragraph 4 of the Commission's order in Docket No. G-5, Sub 509, the Commission explicitly ordered PSNC to "fully explain if it disagrees with the Commission's perception of potential conflicts with the operation of Sections 4 and 5 of the Natural Gas Act or, alternatively, explain what steps it has taken to redress the potential conflict as perceived by the Commission."

With regard to Section 5, witness Jackson testified that Section 5 allows FERC to reduce rates on the FERC's motion or upon a complaint of a party. However, relief is prospective only. Section 5 includes no provision for refunds. Witness Jackson discussed the bill introduced by Senator Cantwell in March 2009 and testified that the bill would, among other things, "amend Section 5 to provide a refund effective date within a period of 150 days after FERC publishes notice of its intent to initiate a Section 5 proceeding or, if the proceeding is initiated by the complaint of a party, within 150 days after the date on which the complaint was submitted to FERC. The maximum period for which FERC could order refunds would be 15 months after the refund effective date set by FERC." Witness Jackson testified that the Cantwell bill is still pending in the Senate Energy Committee. Witness Jackson then testified that supporters of the Cantwell bill state that it would

> put natural gas consumers on the same footing as electric power customers with respect to FERC's ability to review and timely set just and reasonable rates. They argue that the absence of Section 5 refund authority encourages pipelines subject to complaints to delay the proceedings as long as possible.

Witness Jackson summarized the position of the Cantwell bill's opponents by stating that they

> argue that subjecting pipelines to additional refund risk would inhibit infrastructure development that in the past has facilitated the delivery of additional, sometimes stranded, natural gas supplies to markets because pipelines would be required to establish a reserve for potential refund liability and shift

resources from project development to complaint case defense and additional rate case litigation. They say that adding risk to a pipeline's revenue stream would cause investors to become less willing to provide capital for interstate pipeline projects or result in a higher cost of capital to compensate for this greater risk.

PSNC witness Jackson testified that, if there were a perceived conflict of PSNC's interest in Pine Needle, PSNC's customers are protected from any potential harm. She testified that PSNC's core function is to provide regulated natural gas service to its customers and that PSNC would in no way let its minority interest in Pine Needle interfere with its primary function of serving its customers. PSNC witness Jackson testified that the way in which PSNC separates its interest as a minority equity member of Pine Needle and as a Pine Needle customer redresses any perceived conflict. In PSNC witness Jackson's role as a service company employee charged with supporting PSNC's gas supply and capacity management functions, she represents PSNC as a customer of Pine Needle. She testified that she has no involvement in PSNC's participation in Pine Needle as an equity member but supports PSNC in its dealings with Pine Needle in the same way that she supports PSNC in its dealings with other FERC-regulated entities. Similarly, the PSNC personnel in its Gas Supply group that PSNC witness Jackson's department works with on these matters are not involved in Pine Needle for PSNC in its status as an equity member. Accordingly, if there were a potential conflict, PSNC witness Jackson testified that this separation of customer and ownership functions protects PSNC's customers from any potential harm.

Public Staff witness Hoard stated that any perceived or potential conflict associated with the relationship between PSNC and Pine Needle has existed from the beginning and the Public Staff expects both PSNC and its affiliates to abide by the PSNC Code of Conduct and the related separation of customer and ownership functions, as discussed by PSNC witness Jackson. Witness Hoard 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 stated 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 covered by the NGA 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 concluded by stating that the Public Staff supports 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.

Upon examination by Commissioner Culpepper, witness Jackson acknowledged that "the Company" has lobbyists in Washington who keep track of what is going on and actively lobby members of Congress. Witness Jackson further testified that "Conceptually, PSNC would favor changes to the Natural Gas Act as related to the Section 5 provisions that have been proposed in a number of bills."

When examined by Commissioner Culpepper about the Company's position on the Section 4 "rate refund floor," witness Jackson responded that the legislation PSNC has reviewed has not specifically addressed the rate refund floor. She added that PSNC understands that interstate pipeline companies are concerned that the removal of the rate refund floor could potentially impact their opportunities for growth. She added that the removal of the rate refund floor could also potentially impact the way that the FERC would review the risk associated with an interstate pipeline, so PSNC's concern would be, "what type of impact could that have to our overall rates on an interstate service provider?" PSNC expressed concern over whether that would, "make it more difficult for them to have access to capital, which would make it more difficult to continue to grow their infrastructure? And what type of rate of returns could possibly be granted to pipelines in that event?"

It seems to the Commission that the proper way to establish the rate of return necessary to call forth capital to fund the continued growth of interstate infrastructure is through the normal course of formal proceedings before the FERC. There, the interstate companies would be free to present arguments to justify higher returns and other parties would be free to argue that lower returns would be adequate. The Commission is well aware of the need for additional interstate infrastructure and believes that the interests of the State of North Carolina are best served if interstate entities are allowed an opportunity to earn a fair return, if they are prudently operated. However, the Commission does not agree that the best method to establish a rate of return in support of interstate infrastructure expansion is the continued use of the Natural Gas Act in its current form.

As noted by Public Staff witness Hoard, the conflict associated with the relationship between PSNC and Pine Needle has existed from the beginning. The Commission, of course, approved the contract between PSNC and Pine Needle which resulted in the Company being both an owner -- through an affiliate -- and a customer of a FERC-regulated facility. However, given the obvious tension inherent in the roles of owner and customer, such an arrangement by an LDC calls for a continual effort on the part of the LDC to protect the interests of customers as it would if it did not have an equity interest.[1] The Commission expects PSNC to put forth efforts necessary in this regard on behalf of its customers.

The Commission acknowledges that PSNC and the Public Staff both support enactment of legislation that would modify Section 5 in a manner which provides the FERC NGA refund authority that parallels the authority provided to the FERC in the Federal Power Act. 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 Commission concludes that the gas costs incurred by PSNC during the test period ended March 31, 2010, were reasonable and prudently incurred and that the Company should be permitted to recover 100% of its prudently incurred gas costs. Further, the Commission finds that PSNC's current gas supply pricing mechanisms are reasonable and prudent. The Commission also concludes that PSNC should continue to monitor various pricing mechanisms that may become available in the future.

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[1] The Commission recognizes that the federal "filed rate doctrine" precludes this Commission from reducing the amount of Pine Needle costs that PSNC can pass through to its ratepayers.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

The evidence for this finding 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 new temporary increments applicable to both the All Customers Deferred Account and the Sales Customers Only Deferred Account.

Public Staff witness Larsen testified that the Public Staff agrees with PSNC's calculated increment 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 in the instant docket. At the hearing in this proceeding, PSNC witness Paton stated that the Company agreed with the All Customers Deferred Account temporary increments calculated by Public Staff witness Larsen.

Commissioner Culpepper examined witness Larsen as to what effect the recommended temporary increments would have on a typical residential customer's bill. Specifically, Commissioner Culpepper emphasized that he would like to know the effect of the increase on a monthly basis. Witness Larsen testified that he would provide the Commission with a late-filed exhibit that would provide details of the effect of the proposed rate changes.

In Public Staff Late-Filed Exhibit No. 2, the Public Staff provided the effect of the proposed temporary increments on a typical residential customer as detailed in the following table:

Description	Winter Season		Summer Season		Annual Period	
	($)	(%)	($)	(%)	($)	(%)
Change In Temporaries ($/therm)	$0.06335		$0.05648			
Average Seasonal Change	$35.60		$5.48		$41.08	
Average Monthly Bill Change	$5.93	5.45%	$0.91	3.49%	$3.42	4.90%

Based upon the foregoing, the Commission concludes that it is appropriate for PSNC to remove all temporary rates that were implemented in Docket No. G-5, Sub 509, and to implement the temporary increments as proposed by Company witness Paton and Public Staff witness Larsen.

IT IS, THEREFORE, ORDERED as follows:

1. That PSNC's accounting for gas costs for the twelve-month period ended March 31, 2010, is approved;

2. That the gas costs incurred by PSNC during the twelve-month period ended March 31, 2010, were reasonably and prudently incurred, and PSNC is hereby authorized to recover 100% of these gas costs as provided herein;

3. That PSNC shall make an entry in its All Customers Deferred Account to reflect the ($93,464) credit, plus interest, related to emergency gas services that PSNC billed customers during the review period;

4. That PSNC shall credit any future emergency gas surcharges it bills to customers to its deferred accounts;

5. That in its next annual review of gas costs, PSNC shall report to the Commission on its efforts to amend the Natural Gas Act as discussed herein;

6. That in its next annual review of gas costs, PSNC shall file testimony addressing the information, other than the models, that it uses in its hedging program and addressing how it has or will deviate from the guidance provided by its models. Such testimony shall address forward-looking market projections by accepted experts in the natural gas field and, if so, how such projects are used.

7. That PSNC shall remove the existing temporaries that were implemented in PSNC's last Annual Review of Gas Costs proceeding in Docket No. G-5, Sub 509 and shall implement temporary rate increments proposed by Public Staff witness Larsen in the instant docket, effective for service rendered on and after November 1, 2010; and

8. That PSNC shall give notice to its customers of the rate changes allowed in this Order.

ISSUED BY ORDER OF THE COMMISSION
This the 16th day of December, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

WG121610.01

DOCKET NO. G-9, SUB 569

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Piedmont Natural Gas Company, Inc., for Annual Review of Gas Costs Pursuant to G.S. 62-133.4(c) and Commission Rule R1-17(k)(6)	))))	ORDER ON ANNUAL REVIEW OF GAS COSTS

HEARD IN: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on Tuesday, October 6, 2009, at 9:00 a.m.

BEFORE: Commissioner Lorinzo L. Joyner, Presiding; Chairman Edward S. Finley, Jr.; and Commissioner Robert V. Owens, Jr.

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 August 3, 2009, 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 of Keith P. Maust, Managing Director, Gas Supply and Scheduling; the direct testimony of William C. Williams, Managing Director, Transportation and Major Account Services; and the direct testimony and exhibits of Robert L. Thornton, Director of Gas Accounting, attesting to the prudence of the Company's gas purchasing policies and the accuracy of the Company's gas cost accounting for the twelve-month period ended May 31, 2009.

On August 7, 2009, 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 6, 2009, set prefiled testimony dates, and required the Company to give notice to its customers of the hearing on this matter.

On September 1, 2009, the Attorney General filed his notice of intervention.

On September 21, 2009, the Company filed the supplemental testimony of Frank Yoho and the supplemental testimony and exhibits of Robert L. Thornton and a request for an extension of time for the filing of intervenor testimony. On September 21, 2009, the Commission also issued an Order Granting Extension of Time.

On September 23, 2009, the Public Staff filed the direct testimony of Michelle M. Boswell, Staff Accountant, Accounting Division; the direct testimony of Richard C. Ross, Utilities Engineer, Natural Gas Division; and the direct testimony and exhibit of James G. Hoard, Assistant Director, Accounting Division.

On September 29, 2009, the Company filed its affidavits of publication.

On October 2, 2009, the Company and the Public Staff filed a Stipulation for consideration by the Commission.

No other party filed testimony.

On October 6, 2009, the matter came on for hearing as scheduled and all prefiled testimony and exhibits were admitted into evidence. Company witnesses Yoho, Maust, Thornton, and Williams, and Public Staff witnesses Boswell, Ross, and Hoard testified at the hearing. No public witnesses appeared at the hearing.

Based on the testimony and exhibits received into evidence and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

1. 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, 2009.

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 $692,417,302.

7. Pursuant to the Commission's order in Docket No. G-100, Sub 67, the Company credited 75% of the net North Carolina compensation from secondary market transactions, which amounted to $28,168,392, to its All Customers Deferred Account.

8. At May 31, 2009, the Company had a credit balance of $19,585,025 in its Sales Customers Only Deferred Account and a credit balance of $25,265,843 in its All Customers Deferred Account.

9. During the period of review, and pursuant to a settlement between the Company and the Office of Enforcement of the Federal Energy Regulatory Commission (FERC), Piedmont was assessed and agreed to pay a $1,250,000 civil penalty for alleged flipping violations. This penalty was not charged to ratepayers. Piedmont admitted making the capacity releases in question, but neither admitted nor denied the FERC Office of Enforcement's conclusion that it had violated 18 C.F.R. Section 284.8.

10. 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.

11. At May 31, 2009, the adjusted balance in the Company's Hedging Deferred Account is a $155,043,514 debit amount.

12. It is appropriate for the Company to transfer the $155,043,514 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 $135,458,489.

13. 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.

14. 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.

15. 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. However, the Commission is concerned about Piedmont's practice of contracting for interstate capacity from entities in which Piedmont also has an equity interest.

16. The Company should be permitted to recover 100 percent of its prudently incurred gas costs.

17. The Company should implement the temporary increments and decrements recommended by Company witness Thornton.

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.

NATURAL GAS – ADJUSTMENT OF RATES/CHARGES

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3 - 8

The evidence supporting these findings of fact is contained in the testimony of Company witnesses Maust, Thornton, and Williams, the supplemental testimony of Company witnesses Thornton and Yoho, the testimony of Public Staff witnesses Boswell, Ross, 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 twelve-month review period concerning its actual cost of gas, volumes of purchased gas, sales volumes, negotiated sales volumes, and transportation volumes. Commission Rule R1-17(k)(6)(a) establishes May 31, 2009, 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). He included the annual data required by Commission Rule R1-17(k)(6)(c) as Exhibit RLT-1 to his direct testimony. Company witness Thornton provides revisions to Schedules 1, 2, 4, and 5 of Exhibit RLT-1 in his supplemental testimony. Company witness Thornton states that Piedmont incurred gas costs of $692,417,302 during the review period.

Public Staff witness Boswell testified that Company witness Thornton's Exhibit RLT-1, as revised in Company witness Thornton's supplemental testimony, properly reflects the amount of gas costs incurred by the Company during the review period and the deferred account balances as of May 31, 2009.

Public Staff witness Boswell stated that during the review period for this annual review of gas cost (ARGC) the Company credited to its All Customers Deferred Account $28,168,392 for secondary market transactions for the benefit of ratepayers. The margin on secondary market transactions included asset management agreements, capacity releases, bundled sales, and physical puts. Witness Boswell testified that there was a large increase in asset management sales and a large decrease in bundled sales because the asset managers were able to get a better return on those deals and because the Company maintained more control over the assets by going with an asset manager agreement over a bundled sales agreement.

Company witness Maust testified that secondary market transaction credit was $2,741,303 less in this review period compared to the prior year. He stated that this was primarily due to the weakened economy that resulted in less need for released capacity. He stated that as the economy gets better, the value of Piedmont's assets in the secondary market will increase. However, witness Maust also testified that the changes in capacity and natural gas supply downstream of North Carolina -- such as the Rockies Express pipeline into Ohio -- could result in a decrease in the value of downstream capacity such as that being released by Piedmont. He added that addition of such downstream capacity could also affect the basis paid for the commodity itself, with Rockies gas offsetting gas coming up from the Gulf. If so, the cost of gas on the Gulf Coast could actually go down, benefitting Piedmont's customers.

Company witness Thornton and Public Staff witness Boswell testified that as of May 31, 2009, the Company had a credit balance of $19,585,025 in its Sales Customers Only Deferred Account and a credit balance of $25,265,843 in its All Customers Deferred Account.

No other party presented evidence on these issues.

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 $692,417,302 of gas costs during the review period ended May 31, 2009. In addition, the Commission concludes that the appropriate balances of the Company's deferred accounts as of May 31, 2009, are a credit balance of $19,585,025 in its Sales Customers Only Deferred Account and a credit balance of $25,265,843 in its All Customers Deferred Account.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The evidence supporting this finding of fact is contained in the direct testimony of Public Staff witness Boswell. Witness Boswell testified that the FERC Office of Enforcement opened an investigation into possible flipping activities of natural gas participants in the capacity release market. FERC concluded that Piedmont had improperly released 20.33 billion cubic feet of discounted-rate capacity through flipping transactions between August 2005 and October 2007. Piedmont admitted making the capacity releases in question, but neither admitted nor denied FERC's conclusion that the releases violated 18 C.F.R. Section 284.8. FERC and Piedmont resolved the investigation by an agreement that Piedmont pay a $1,250,000 civil penalty. Piedmont recorded the entire penalty in Account 42630, a non-utility below-the-line item, and therefore, the payment of the civil penalty had no impact on ratepayers.

No other party filed evidence on this issue.

The Commission concludes that the civil penalty was recorded in a non-utility below-the-line account, and, therefore, had no direct impact to ratepayers.

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

The evidence supporting these findings of fact is contained in the direct testimony of Company witnesses Maust and Thornton, supplemental testimony of Company witness Yoho, direct testimony of Public Staff witnesses Boswell and Hoard, and the Stipulation filed by the Company and the Public Staff.

Company witness Thornton stated in his direct testimony that the Company had a total debit balance of $156,196,742 in its Hedging Deferred Account at May 31, 2009. Public Staff witness Hoard testified that much of these hedging costs were due to Piedmont's sale of put options in August and September 2008 at strike prices between $6.00 per dekatherm (dt) and $8.00/dt. Some of these options covered contract months as far into the future as November 2010, seventeen months beyond the review period. Witness Hoard testified that when natural gas prices fell dramatically beginning November 2008, the counterparties exercised their put options, which caused the Company to pay the difference between the option strike prices and the monthly settle prices.

Company witnesses Maust and Yoho testified that the Piedmont 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. Witness Yoho testified that Piedmont uses the Risk Management Incorporated (RMI) model for its hedging plan which takes in a four-year average and runs an historical analysis. Witness Yoho further testified that the leaning in Piedmont's plan is to protect customers against price fly-ups. Witness Maust and witness Yoho also testified that the gas accounting, finance, and corporate compliance areas of Piedmont perform ongoing activities to monitor compliance with the Hedging Plan and that there were no deviations from the Hedging Plan during the review period. Witness Yoho testified Piedmont tries to keep the plan as program-driven as possible, unless there is a real reason to change it, and that the plan has worked very hard to "keep it pure to historics, facts and stay away from personal emotion and opinions."

Witness Yoho testified that due to unique and unpredictable circumstances impacting the wholesale domestic market for natural gas -- including supply, demand, market participants, the economic recession, the additional production of shale natural gas, the success of horizontal drilling, and the interstate pipeline infrastructure projects -- Piedmont's hedging program resulted in much higher-than-normal costs for its customers during this period. Witness Maust and witness Yoho also testified that the Company has modified its Hedging Plan by shortening the hedging horizon from twenty-four months to twelve months, and reducing the amount of hedging transactions the Company will engage in from a range of 30% - 60% of annualized sales volumes to a range of 22.5% - 45%. Public Staff witness Hoard testified that if the Company hedges less, the gains and losses will be less. He further testified that the switch from a time horizon of twenty-four months to twelve months is a good one. Witness Yoho testified that Piedmont has reduced the amount of hedging transactions because Piedmont is no longer in a supply-constrained environment and that Piedmont has shortened the hedging horizon because the hedging is getting too volatile and too costly for the products relative to the value that customers were getting.

Public Staff witness Hoard testified that Piedmont used the volume level of 77,153,429 dekatherms from its 2005 rate case in determining the target level of volumes for hedging purposes. Witness Hoard stated Piedmont knew or should have known that its normalized sales volumes had declined and should have adjusted the volumes it used for hedging purposes accordingly. Witness Hoard computed a $1,575,536 credit adjustment to the Company's Hedging Deferred Account based on the 2007/2008 budgeted volumes, since that level was known by Piedmont at the beginning of the current review period. In his direct testimony, he stated, "based on the facts known at the time and except for decisions made regarding the volumes hedged, the Company's hedging decisions were prudent." In the Stipulation filed on October 2, 2009, Piedmont and the Public Staff, without conceding the correctness of the other party's position, agreed that the proper ending debit balance in Piedmont's Hedging Deferred Account as of May 31, 2009 was $155,043,514. This amount represented a downward adjustment to the benefit of Piedmont's customers of $1,153,228 from the end of review period balance of $156,196,742 reported in Piedmont's August 3, 2009 filing in this proceeding. In addition, the parties agreed pursuant to the Stipulation that Piedmont's hedging decisions during the review period were reasonable and prudent.

The RMI model employed by Piedmont in its hedging program has been described to the Commission in some detail since its introduction in Docket No. G-9, Sub 454, in 2002. In that instant docket, Piedmont witness Maust testified:

> The Company implements hedges when market prices reach attractive levels based upon a matrix composed of 4 years of historical prices developed by RMI. The matrix is broken down into ten percent decile levels, with hedges being implemented for value when future market prices (NYMEX) reach the 50th decile level and lower. If forward prices don't reach the 50th decile level prior to five months before a winter or summer season, the Company will implement hedges on a more limited basis to obtain a reduced level of protection prior to a winter or summer season.

Both Company witnesses Yoho and Maust and Public Staff witness Hoard testified in this case that the RMI model not only signaled for Piedmont to initiate hedging activity at high prices during the review period, but that the signals issued by the model were strong ones.

Witness Yoho was asked about the causes of the 2008 price run-up. He responded that there were supply factors, demand factors and "participants in the market factors." For supply factors, he asserted that "we were still under the environment of a supply constrained market." For demand factors, he pointed to a late winter and stated that "storages were drawn lower than they had been." He added, "It was an early summer, so in June there was a lot of power generation." He did not elaborate on his comments about "participants in the market factors." He did point to the high oil prices and asserted that "there was a lot of concern" that the high oil prices left room for gas prices to go up.

As for the sharp subsequent price decline, witness Yoho attributed that to the development of the shale plays and the global recession. Witness Yoho was asked if there were any discussions within Piedmont's management when the highs were hit in the summer of 2008 concerning the possibility of a fall in natural gas prices and the need to take a look at the RMI model. His response was that Piedmont was, "...very fearful of prices for our customers running up to the 12, 13, 18 dollar range, which, was a concern at that period of time."

Piedmont witness Maust also commented on the U.S. natural gas supply situation. He testified:

> The United States had been struggling to avoid a gradual decline in natural gas production, with prices for future delivery on the NYMEX reaching a peak of $14.516 for January 2009 supply on July 3, 2008, with the 12 month futures strip averaging $13.334 on the same date. Spurred by the huge increase in prices, producers increased their investment in new production, doubling the rig count and outlaying capital for lease acquisitions in unconventional gas plays like the Marcellus, Haynesville, Fayetteville, Woodford, and Barnett Shales. Due to the prolific increase in production from the dramatic increase in drilling rigs, new production from shale plays and a drastic reduction in demand due to the global

recession, the country is now in the midst of a gas bubble less than 12 months later.

The Commission asked Piedmont witness Maust about the impact of financial entities in the market on the price of natural gas and what consideration Piedmont had given to the issue of "so-called excessive speculation." Witness Maust responded that Piedmont was participating through AGA and "talking about how at least gas companies would like to be treated as far as its ability to be able to do hedges." He made reference to "posting collateral requirements." However, he added, "Piedmont's really not set up to address whether there's excessive speculation going on or not in the market. I think there needs to be some type of speculation in the market to provide liquidity. The level of that speculation that needs to be allowed is best addressed by the CFTC and government agencies." When asked about Piedmont's opinion of the efficacy of bills pending before Congress dealing with excessive speculation, witness Maust responded, "...everything that we're dealing with as far as excessive speculation...is through AGA."

When examined by the Commission, witness Yoho agreed that Piedmont's hedging decisions are based in large measure on the RMI model and that the model is a "formulated application to historical events." He was asked, "When you have these perfect storm conditions that are going to drive the market up, is management not able to look at that and to step out of the RMI model and make adjustments to the hedging program?" Witness Yoho's response was, "We would have the ability, but as soon as we do that, we, I would say, would be going into speculation. And our plan is very much in regards to...stay away from emotion ...."

In Docket No. G-9, Sub 454, Piedmont proposed that its gas-hedging program should be filed with and approved by the Commission, that all costs incurred by Piedmont should be recovered from customers, that if the Commission approved the gas-hedging program with conditions, Piedmont should have the option of accepting the conditions or withdrawing the program, and that "[a]ll costs incurred by Piedmont in connection with its implementation and administration of the hedging program...as well as the costs of all gas purchased under the hedging program, should be deemed prudent and subject to full recovery in Piedmont's gas costs recovery mechanism." The Commission ruled in both Docket No. G-100, Sub 84, and Docket No. G-9, Sub 454, that, as a matter of law, it could not rule that costs associated with hedging were gas costs within the meaning of G.S. 62-133.4 (and subject to pass-through under that statute) and also allow for pre-approval and the presumption of prudence if hedging was carried out within the framework of a pre-approved plan. The Commission explicitly ruled that hedging decisions had to be subject to review.

The Commission asked in this docket whether, in view of the turbulence experienced during the current review period, the parties continue to believe that hedging is in the best interest of ratepayers. In examining Piedmont witnesses, the Commission noted that hedging has been described as an insurance policy against price volatility, but asked whether the benefits of reducing volatility are worth the $156 million seen in this period. Both Company witness Yoho and Public Staff witness Hoard supported the continuation of hedging. Company witness Yoho testified that right now the Company thinks hedging, as it has been adjusted, makes sense, but that the Company's continuing support for hedging is dependent upon a strong consensus from all parties. Company witness Yoho further testified that he believes the hedging program is for the benefit of the customer to reduce the volatility, but the customer pays the price. Public Staff witness Hoard testified that he believes hedging is still worthwhile, but that it should be evaluated from the perspective of an LDC and that hedging by an LDC may not necessarily follow what is done by a commercial interest.

The Commission is concerned that Piedmont's end of review period balance in its hedging account is $156,196,742. The purpose of hedging is to reduce volatility in the cost of natural gas borne by consumers. Costs in excess of $156 million is an exceptionally high price to pay for this putative benefit. Piedmont's customers justifiably can ask whether the reduction in volatility they have experienced is worth this price. Piedmont has attempted to explain the unusual factors that resulted in these costs. Also, Piedmont stresses that the Company has undertaken its hedging program for the benefit of its customers, has relied upon the formulaic signals of the RMI model and should not be penalized because the model produced costs at excessive levels compared to historical averages. Piedmont stresses the need for consensus among stakeholders as necessary support for its continued participation in its hedging program.

The Public Staff has recommended only several minor adjustments to reduce the $156 million to $155 million. The Commission therefore does not have a record before it in this docket to make further adjustments or to support additional findings of imprudence or unreasonableness. The Commission understands Piedmont's challenges in responding to a period fraught with unusual circumstances. Nevertheless, the Commission must stress that the decision to hedge, how much gas to hedge, the time frames for the hedges, the models to employ and the decisions to deviate from the signals from the model rest in the first instance solely with Piedmont's management. As the Commission has made clear in the past, the Commission does not issue utility management a blank check that insulates it from imprudent decisions. Piedmont is not free from regulatory risk in the decisions it makes in the undertaking and implementing its hedging program. Piedmont is not free to respond to the Commission's directives by saying if too little assurance is forthcoming from the Commission so as to reduce the Company's regulatory risk, it will discontinue the hedging program. Neither is Piedmont free to say we adopted a model, the model produced signals and we followed them when such decisions produce results that are unsupportable. It is one thing to stick to a model rather than abandon it in response to the emotion of the moment. It is quite another to stick to a model when reasonableness and common sense suggest that the model's signals are in error. If other companies situated similarly to Piedmont can employ a hedging program that has reasonably reduced volatility with far less costs during a given period than Piedmont has, Piedmont should be able to do likewise.

The Commission expresses its grave concern over the magnitude of the hedging costs Piedmont's customers are to bear. The Commission expects Piedmont to follow management practices henceforth that produce a reasonable moderation in customer gas cost volatility through a hedging program with costs commensurate with the benefits it produces.

The Commission notes that, from the inception of the hedging effort by the local distribution companies (LDCs), the LDCs appear to have been focused on controlling the regulatory risk that arises from hedging. As is mentioned in the Commission's February 26, 2001 Order on Hedging, "LDCs have, in the past, been reluctant to hedge for fear that favorable results would be passed through to ratepayers, but unfavorable results would be deemed imprudent and would have to be absorbed by the LDCs." Piedmont, in particular has shown a strong desire to eliminate regulatory risk. In its comments in Docket No. G-100, Sub 84, Piedmont stated that it believed that it was:

> ...appropriate for LDCs to hedge under the appropriate circumstances. Those circumstances include, but are not limited to, (a) providing each individual LDC the option, but not the requirement, to hedge (b) pre-approval of the recovery of all incremental costs associated with hedging, including any costs or expenses associated with margin requirements should the price of gas fall below (or, in the case of a short sale, rise above) the hedged price, and (c) the absence of any hindsight review or second guessing of hedging activities.

The Commission notes that, since the initiation of Piedmont's formal hedging program, several regulatory changes have been made that arguably have had the effect of reducing Piedmont's sensitivity to high natural gas prices. In a general rate case in Docket No. G-9, Sub 499, the Commission accepted a settlement that included the Company's proposal to remove the gas cost portion of the uncollectible accounts expense from the Company's cost of service. The Company now recovers gas costs related net write-offs through the Sales Only Customers Deferred Gas Cost Account. The Commission recognizes that this new practice benefits the ratepayer if the price of natural gas decreases. However, the fact remains that recovery of net uncollectible commodity costs through the Sales Only Customer Deferred Account insulates Piedmont from what has previously been an incentive to hold down natural gas commodity costs. Also in Docket No. G-9, Sub 499, the Commission accepted a margin decoupling mechanism, referred to in that docket as the "Customer Utilization Tracker" (CUT). The CUT mechanism allows Piedmont to implement increments to recover the amount of margin approved in the rate case in the event that customers reduce their consumption below the level anticipated in designing rates. Such a mechanism also provides protection for volume reduction due to conservation spurred by high natural gas prices. Both of these changes insulate Piedmont's near-term income from the adverse effects of a run-up in natural gas prices.

The Commission reiterates that the LDCs benefit from hedging as well as the ratepayers. In the Order on Hedging in Docket No. G-100, Sub 84, based on comments received from Toccoa Natural Gas, the Commission stated, "The risk that customer discontent over price volatility could lead to load loss should provide motivation for a prudent LDC to assess and, if feasible, to implement a plan to mitigate commodity price volatility." If an LDC stands by idle while its customers leave in frustration over price volatility, and then tries to recover its fixed cost from a declining customer base, shareholders will eventually see increased risk.

Witness Yoho testified that the rig count is half of what it was at this time last year and "it very definitely is going to have an effect on the deliverability of supply." He testified that there could "most definitely" be a rise in prices. Given that, the Commission encourages Piedmont to continue a dialogue on hedging with the Public Staff and other interested parties considering both the goals and costs of hedging.

Another issue of interest to the Commission involves the sale of puts that caused much of the losses incurred during the review period. Public Staff witness Hoard testified that the sale of puts resulted in over $60 million of losses for positions closed during the review period plus an additional $50 million of losses on positions that were still open at the end of the review period. Witness Hoard questioned the advisability of selling put options and also call options since the sale of options exposes the Company and ratepayers to basically unfettered losses. With respect to the sale of puts, witness Hoard also testified that they effectively mitigated downside price volatility which was not desirable for ratepayers. Company witness Yoho testified at the hearing that the Company has modified its Hedging Plan to reduce the portion of its supply that it hedges and its hedge horizon (the number of months into the future that it hedges) which tends to reduce, but not eliminate, any risk of loss to customers associated with these types of hedging transactions.

The Commission notes that Piedmont did not directly respond to witness Hoard's testimony regarding the advisability of continuing to sell put and call options despite the very significant losses experienced from the sale of puts during the review period. While the Commission is not opposed to the use of sophisticated hedging techniques per se, the Commission believes this is a significant issue and desires the Company's input on whether these types of hedging transactions should be continued given recent experience. Accordingly, the Commission directs Piedmont to make a filing, within sixty (60) days of the issuance of this Order, stating its position as to whether it intends to engage in the sale of put and call options under its hedging program in the future and explaining its position in that regard.

Public Staff witness Hoard testified that "Piedmont determined the portion of supply needs that it should hedge based on the recommendation of RMI at the inception of the Company's hedging plan and the range of percentages currently used by RMI's other gas utility clients." Piedmont has decided to reduce the amount of hedging transactions it will engage in from a range of 30% - 60% of annualized sales volumes to a range of 22.5% - 45%. 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.

The Commission recognizes that the Public Staff conducted its investigation of Piedmont's hedging practices during this review period and made an initial recommendation that Piedmont be deemed imprudent with regard to the volumes hedged but prudent in all other respects. Subsequently, the Public Staff agreed to a Stipulation that provides that Piedmont's hedging practices during the review period were prudent, but reduces Piedmont's Hedging Deferred Account Balance by $1,153,228. The Commission understands that -- as was stated in Public Staff witnesses' testimony -- the Public Staff examined Company records and received data requests. Many of those were not put before the Commission in the record in this docket. While the Commission is not bound by the Stipulation in this case, and while the Commission might have reached a different result had further evidence been presented and had hedging issues been fully litigated, the Commission approves the settlement.

Based on the testimony presented by the Company and the Public Staff and the Stipulation filed by the Company and Public Staff, and the lack of testimony arguing to the contrary, the Commission concludes that the Company's hedging activities during the review period should only be adjusted so that a debit balance of $155,043,514 in the Company's Hedging Deferred Account as of May 31, 2009, should be transferred to the Company's Sales Customers Only Deferred Account. The combined balance for the Company's Hedging and Sales Customers Only Deferred Accounts is a debit balance of $135,458,489. However, the Commission cautions Piedmont that it expects the Company to administer its hedging program with the reasoned judgment of a professional natural gas local distribution company. It expects a hedging program with goals tailored to meet the needs of its customers.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 13 - 16

The evidence supporting these findings of fact is contained in the testimony of Company witnesses Maust, Williams, and Yoho, and Public Staff witness Ross.

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 also testified that there were not any situations or incidents that impacted the security of supply during the review period.

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 2012. 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 in 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 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, and subscribing to industry literature.

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 are affected by overall demand, oil and gas exploration and development, pipeline expansion projects, and regulatory policies and approvals. He 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 witnesses Maust and Yoho also testified regarding the current U.S. supply situation, the impact of oil prices on the price of natural gas, the effect of electric generation fueled by natural gas on the price of natural gas, and the various pricing alternatives available, such as fixed prices, monthly market indexing, and daily spot market pricing. In explaining the sharp drop in gas prices seen during the review period, witness Yoho testified at the hearing that natural gas production has increased, primarily due to Marcellus and Haynesville shale production, and that the effects of this shale production were not really known by the industry until recently. However, witness Maust testified that the number of rigs drilling for natural gas is down and if, as a result of reduced drilling activity, natural gas reserves are not replaced as the economy improves, then the price of natural gas will rise.

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 or 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 seen evidence that conservation/reduced usage occurs during the coldest of days. Witness Williams testified that this is called the "hooking effect." He testified that "when it first starts to get cold, customers may put on a sweater...throw a blanket on. But after they turn the thermostats up, if the cold front is sustained, that they leave it up for awhile." For that reason, witness Williams testified, Piedmont will continue to utilize a conservative approach in its forecast of demand on those days. Piedmont has no plans to add incremental capacity during the 2010/2011, 2011/2012, or 2012/2013 winter seasons.

In asking for the CUT in Docket No. G-9, Sub 499, Piedmont argued that the increased efficiency of natural gas appliances and the increased insulation in homes and businesses (among other things) reduced the average demand per ratepayer between rate cases and justified the introduction of a CUT. Logic dictates that if customers are installing more efficient equipment and building tighter homes and businesses, then the average consumption per design day should also decrease. The calculation of design day demand dictates how much incremental firm interstate capacity is added. And that capacity can also be released in secondary market transactions. Pursuant to the Commission's order in Docket No. G-100, Sub 67, Piedmont passed through $28,168,392 in proceeds from net North Carolina secondary market transactions during the review period. It also retained 25% of those proceeds or approximately $9.4 million for its shareholders. The Commission notes that this may arguably create the potential to overstate design day needs.

Public Staff witness Ross testified that he had reviewed the testimony and exhibits of the Company 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, witness Ross testified that the Company's review period gas costs were prudently incurred.

No other party presented evidence on these matters.

In Piedmont's last ARGC in Docket No. G-9, Sub 554, Piedmont witnesses Maust and Williams were asked about Piedmont's purchase of capacity from Pine Needle LNG LLC, a FERC-regulated entity in which an affiliate of Piedmont has an ownership interest. Witness Williams was explicitly asked about the impact on customers of the so-called "rate refund floor" which stems from Section 4(e) of the Natural Gas Act. Witness Williams responded that he didn't "particularly see it as a problem." In its Order on Annual Review of Gas Costs in that docket, the Commission expressed concern, based on its experiences before the FERC pursuant to G.S. 62-48(b), over the impact of the rate refund floor on customers and interstate companies and ordered the Company to fully explain Mr. Williams' position, or alternatively, to describe to the Commission what steps it has taken to redress the problem with the rate refund floor as perceived by the Commission.

In this Docket, the Company continues to take the position that the rate refund floor does not create any problems for it or its customers. In response to the Commission's directive in Sub 554, Company witness Williams offered four points to more fully explain its position. First, he stated that the refund floor only comes into effect when a FERC-regulated natural gas company experiences a reduction in its cost of service between rate cases, an experience that he describes as "a relatively rare occurrence." Second, he argued that "the effect of the refund floor is a factor to be considered in settlement discussions but not a determinative one because it is economically less significant and of shorter duration in effect than many other issues in rate cases." Third, he stated that, as explained to him by counsel, the refund floor is a doctrine of federal law arising under the Natural Gas Act which cannot be changed without either federal legislation or a change in the way in which the federal courts interpret Section 4 of the Natural Gas Act. And fourth, he argues that because Piedmont is not the operator of the interstate facilities that it is involved with, it does not conduct rate proceedings and reach settlements and therefore, "to the extent the Commission is concerned that some conflict of interest may result from the operation of the refund floor in these circumstances, Piedmont does not believe that such conflict exists in reality."

This Commission, pursuant to G.S. 62-48, appears before the FERC "...to secure for the users of public utility service in this State just and reasonable rates and service." It is deeply concerned with what it perceives to be flaws in the Natural Gas Act, both with regard to the rate refund floor under Section 4(e) and also with the lack of a refund provision in Section 5. The Commission reasonably expects North Carolina LDCs to vigorously represent the interests of their ratepayers before the FERC with this Commission functioning as a supporter. When the affiliate of an LDC holds an ownership interest in a FERC-regulated natural gas company from which the LDC is obtaining service, the potential for a conflict of interest is obvious. An examination of the testimony offered by Piedmont in this docket does not engender confidence that the Company fully appreciates this potential and the attendant harm it may cause to its ratepayers.

For instance, witness Williams first notes that the refund floor only comes into effect in the circumstances where a FERC-regulated natural gas company experiences a reduction in its cost of service between rate cases and argues that reductions in cost of service between rate cases are "relatively rare." Yet, the Commission notes that both of the FERC-regulated projects that Piedmont is involved with as both a customer and, through an affiliate, an owner are highly capital-intensive, stand-alone storage projects. Pine Needle LNG Company LLC (Pine Needle) and Hardy Storage Company (Hardy)[1] can both reasonably be expected to experience declining net utility plant and therefore declining rate base and cost of service.

Witness Williams also contended that the rate refund floor is "economically less significant and of shorter duration in effect than many other issues in rate cases." The Commission believes that one reason that the rate refund floor does not actually produce more significant and longer duration effects is that the rate refund floor makes it disadvantageous for customers to fully litigate a case, and as a result, customers may feel pressure to enter expedited settlements with less favorable terms than might be achieved through litigation.

Finally, Piedmont stresses that because it is not the operator of the facilities, does not conduct rate proceedings, and does not reach settlements, the operation of the rate refund floor does not create a conflict of interest. Piedmont has placed itself in a position in which a quirk in the federal law benefits its shareholders and harms its ratepayers. The Commission, of course, approved Piedmont's acquisition of an equity interest in Pine Needle, resulting in the Company being both an owner of and a customer of a FERC-regulated facility. Given the obvious tension inherent in these two roles, 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.[2] The evidence presented in this docket does not assuage the Commission's concerns regarding how well those interests are being balanced by the Company.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 17

The evidence supporting this finding of fact is contained in the testimony of Company witness Thornton and Public Staff witness Ross.

Company witness Thornton stated in his supplemental testimony that the Company proposed to place temporary rate elements in rates to adjust amounts held in its deferred accounts.

Public Staff witness Ross testified that he had reviewed the temporary rate increment applicable to the All Customers Deferred Account balance proposed by Company witness

[1] Transcript in Docket No. G-9, Sub 554.

[2] The Commission recognizes that the federal "filed rate doctrine" precludes this Commission from reducing the amount of Pine Needle and Hardy costs that Piedmont can pass through to its ratepayers.

Thornton, as reflected in Exhibit RTL-3, and agrees with the calculations. Witness Ross recommended that the temporary rates implemented in Docket No. G-9, Sub 554, Piedmont's last annual review proceeding, be removed while simultaneously implementing the decrements proposed in Exhibit RLT-3.

Witness Ross further testified that he had reviewed the temporary rate increment applicable to the Sales Customers Only Deferred Account balance proposed by Company witness Thornton, and agrees with the continuation of the temporary increment of $0.05230 per therm, which was implemented in Docket No. G-9, Sub 554.

No other party presented evidence on this issue.

The Commission notes that, in Docket No. G-9, Sub 554, the debit balance in the combined Sales Customers Only Deferred Account and Hedging Deferred Account for the review period ending May 31, 2008, was $37,950,280. The $0.05230 per therm increment implemented in that docket was intended to collect that balance. In this docket, for the review period ending May 31, 2009, the parties agreed to a combined Sales Customers Only and Hedging Deferred Account debit balance of $135,458,489. The stipulating parties have proposed to continue the $0.05230 per therm increment. The Commission should not and will not impose its judgment here, but does note that the parties are placing a heavy dependence on the behavior of the commodity cost of gas over the next twelve months to recover a very large amount of money.

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 to implement the temporary decrements applicable to the All Customers Deferred Account recommended by Company witness Thornton and Public Staff witness Ross, as set forth in Company witness Thornton Exhibit RLT-3 and to continue the temporary increment to the Sales Customers Only Deferred Account, as set forth in Docket No. G-9, Sub 554.

IT IS, THEREFORE, ORDERED as follows:

1. That the Company's accounting for gas costs during the twelve-month period ended May 31, 2009, 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 the Company shall make a filing, within sixty (60) days of the issuance of this Order, stating its position as to whether it intends to engage in the sale of put and call options under its hedging program in the future and explaining its position in that regard;

4. That, in its next annual review of gas costs, the Company shall 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;

5. That the Company is authorized to transfer the $155,043,514 Hedging Deferred Account balance to the Sales Customers Only Deferred Account for recovery;

6. That the Company shall remove the All Customers Deferred Account temporary rates that were implemented in Docket No. G-9, Sub 554, implement the temporary rate decrements to refund the All Customers Deferred Account balance found appropriate herein, and continue the existing temporary increment of $0.05230 per therm related to the Sales Customers Only Deferred Account, effective for service rendered on and after the first day of the month following the date of this Order;

7. That Piedmont shall give notice to its customers of the rate changes allowed in this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 17th day of February, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

wg021710.01

DOCKET NO. G-40, SUB 91

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Frontier Natural Gas Company, LLC, 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, March 2, 2010, at 10:00 a.m., in the Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner Bryan E. Beatty, Presiding, and Commissioners Susan W. Rabon and ToNola D. Brown-Bland

APPEARANCES:

For Frontier Natural Gas Company, LLC:

M. Gray Styers, Jr., Blanchard, Miller, Lewis & Styers, P.A., 1117 Hillsborough Street, Raleigh, North Carolina 27603

For the Using and Consuming Public:

NATURAL GAS – ADJUSTMENT OF RATES/CHARGES

Elizabeth A. Denning, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: On December 1, 2009, Frontier Natural Gas Company, LLC (Frontier or Company), filed the direct testimony and exhibits of David C. Shipley, President of Frontier, in connection with the annual review of Frontier's gas costs pursuant to G.S. 62-133.4(c) and Commission Rule R1-17(k)(6).

On December 8, 2009, the Commission issued its Order Scheduling Hearing, Requiring Filing of Testimony, Issuing Discovery Guidelines, and Requiring Public Notice. This Order established a hearing date, set pre-filed testimony dates, and required Frontier to give at least 30 days prior notice to its customers of the hearing on this matter.

On February 3, 2010, Frontier filed the amended direct testimony and exhibits of David C. Shipley.

On February 15, 2010, the Public Staff filed the direct testimony of Thomas W. Farmer, Jr., Director, Economic Research Division; the direct testimony of Jan A. Larsen, Engineer, Natural Gas Division; and the direct testimony and exhibit of David A. Poole, Staff Accountant, Natural Gas Section, Accounting Division.

On February 24, 2010, Frontier and the Public Staff filed a Joint Motion for Leave to Admit Testimony and Exhibits into Evidence (Joint Motion). The Joint Motion stated that the Company agreed with the findings, positions, and recommendations set forth in the Public Staff's testimony and exhibit filed on February 15, 2010, and requested that the prefiled direct testimony and exhibits of both the Company and the Public Staff witnesses be admitted into evidence without the need for them to appear at the hearing.

On February 25, 2010, the Commission issued an Order Granting Motion to Excuse Witnesses.

On February 26, 2010, Frontier filed its Affidavits of Publication of Public Notice of Hearing.

No other party intervened in this docket.

On March 2, 2010, the matter came on for hearing as scheduled. No public witnesses appeared to offer testimony. Based upon the testimony and exhibits received into evidence and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

1. Frontier is a public utility as defined by G.S. 62-3(23), organized and existing under the laws of the State of North Carolina with its headquarters in Elkin, North Carolina.

2. Frontier is a natural gas local distribution company (LDC), primarily engaged in the business of purchasing, transporting, distributing, and selling natural gas to approximately 1,035 customers in North Carolina, as of November 20, 2009.

3. Frontier has filed with the Commission and submitted to the Public Staff all of the information required by G.S. 62-133.4(c) and Commission Rule R1-17(k), and has complied with the procedural requirements of such statute and rule.

4. The review period in this proceeding is the twelve months ended September 30, 2009.

5. During the review period, Frontier incurred gas costs of $2,227,516, composed of Gas Supply Purchases of $1,948,252, Demand Charges of $238,094, Pipeline Transportation Charges of $24,583, and Scheduling Fees of $16,587.

6. The appropriate Deferred Gas Cost Account balance for Frontier as of September 30, 2009, is a credit balance of $187,432 owed to customers.

7. Frontier properly accounted for its gas costs during the review period.

8. Frontier operated a gas cost hedging program during the review period. Frontier's hedging activities for the review period were reasonable and prudent.

9. Frontier incurred hedging costs of $129,010 during the review period.

10. Frontier should include a schedule in future annual review proceedings in a format comparable to Poole Exhibit 1 that reflects the results of its hedging program.

11. Frontier should take the actions recommended by Public Staff witness Farmer regarding its hedging program.

12. During the test period, Frontier acquired all of its gas from BP Energy Corporation (BP Energy), a wholesale gas supplier with interstate capacity.

13. Frontier has adopted a gas purchasing policy that it refers to as a "best evaluated cost" supply strategy.

14. Frontier's gas purchasing policy and practices during the review period were prudent, and its gas costs during the review period were prudently incurred.

15. Frontier should be permitted to recover 100% of its prudently incurred gas costs.

16. Frontier should not be required to implement a rate decrement at this time.

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

These findings are essentially informational, procedural or jurisdictional and are based on evidence uncontested by any of the parties. The evidence supporting these findings is contained in the official files and records of the Commission and by the testimony and exhibits of Frontier witness Shipley.

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

The evidence supporting these findings is contained in the testimony of Frontier witness Shipley, the testimony of Public Staff witnesses Poole and Larsen, and the provisions of G.S. 62-133.4(c) and Commission Rule R1-17(k)(6).

G.S. 62-133.4 requires that each natural gas utility submit to the Commission information and data for an historical twelve-month review period concerning its actual cost of gas, volumes of purchased gas, sales volumes, negotiated sales volumes, and transportation volumes. Commission Rule R1-17(k)(6)(c) requires the filing of work papers, direct testimony, and exhibits supporting the information.

Frontier witness Shipley 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).

Public Staff witnesses Poole and Larsen confirmed that the Public Staff had reviewed the filings and monthly reports filed by Frontier. No other party filed testimony or presented evidence on this matter.

The Commission, therefore, concludes that Frontier has complied with all of the procedural requirements of G.S. 62-133.4(c) and Commission Rule R1-17(k) for the review period.

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

The evidence supporting these findings of fact is contained in the testimony of Public Staff witness Poole and Frontier witness Shipley. No other party filed testimony or presented evidence on these matters.

Public Staff witness Poole testified that Frontier's total gas costs for the review period were $2,227,516, composed of Gas Supply Purchases of $1,948,252, Demand Charges of $238,094, Pipeline Transportation Charges of $24,583, and Scheduling Fees of $16,587.

Witness Poole testified that every month the Public Staff conducts a review of the Deferred Gas Cost Account reports filed by Frontier to assess their accuracy and reasonableness and performs many audit procedures on the calculations.

Public Staff witness Poole also testified that, as of September 30, 2009, Frontier's Deferred Gas Cost Account had a credit balance of $187,432 owed to customers compared to the prior review period debit balance of $31,948 owed to Frontier. The $219,380 change in Frontier's Deferred Gas Cost Account consists of the gas cost true-up over-collections of $154,701, transportation customer balancing over-collections of $50,528, and accrued interest of $14,151. Frontier witness Shipley provided testimony that concurs with witness Poole's testimony regarding the balances and activity of the Deferred Gas Cost Account.

Witness Poole further testified that Frontier has properly accounted for its gas costs during the review period.

Based on the foregoing, the monthly filings by Frontier pursuant to Commission Rule R1-17(k)(5)(c), and the findings and conclusions set forth above, the Commission concludes that Frontier has properly accounted for its gas costs incurred during the review period and that the Deferred Gas Cost Account balance as reported is correct.

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

The evidence for these findings of fact is contained in the testimony of Frontier witness Shipley and Public Staff witnesses Farmer and Poole. No other party filed testimony or presented evidence on these matters.

Frontier witness Shipley testified that the Company engaged in hedging activity during the current review period. Witness Shipley further testified that pricing was down 42% to 47% compared to the historical first of the month pricing for Transco Zone 3 over the past five years, and that this pricing fell within the boundaries of Frontier's supply hedge price strategy and, thus, it helped Frontier reduce volatility and price risk for its customers.

Public Staff witness Farmer testified that Frontier's hedging program involves purchasing physical hedges for the winter season of November through March and the summer season of April through October. Witness Farmer further stated that, as of the date of filing his testimony, Frontier does not consider it prudent to assume the financial risks associated with futures and options.

Witness Farmer also testified that Frontier hedged for eleven months of the review period by executing two winter strips and two summer strips that allowed the Company to purchase set amounts of natural gas at fixed prices for several months of its winter load and summer load. Witness Farmer further testified that Frontier hedged natural gas within its target range of 25% to 60% of its forecasted volumes for November 2008 through September 2009. Witness Farmer concluded that Frontier's hedging activities during the review period were reasonable and prudent and that it is reasonable to reflect the debit balance associated with its hedging in Frontier's Deferred Gas Cost Account.

Public Staff witness Poole testified that Frontier's hedging activities resulted in a $129,010 increase in gas supply costs. Witness Poole provided a computation of this amount in Poole Exhibit 1 and recommended that Frontier file an additional schedule in a format comparable to Poole Exhibit 1 in future annual review proceedings that reflects the results of its hedging program. Witness Poole further testified that it is his understanding that Frontier agrees with his recommendation.

Public Staff witness Farmer also provided some recommendations regarding Frontier's hedging program. In particular, witness Farmer testified that he recommends that Frontier take the following actions: (1) develop full documentation of its hedging program that includes strategy, goals, authorizations, responsibilities, sources of information used, reporting, etc.; (2) retain all documentation from all sources that supports the decision-making for each hedge or block of hedges executed in the future; (3) discuss any plans for financial hedging with the Public Staff well in advance if the Company believes it may be a viable option in the future; and

(4) continue to evaluate its hedging program, implement improvements as feasible, and continue the dialogue regarding hedging activities with the Public Staff and the Commission.

The Joint Motion contains a statement that Frontier agrees with the Public Staff's findings and positions and recommendations set forth in the Public Staff's testimony and exhibits.

Based on the foregoing, the Commission concludes that Frontier's hedging activities during the review period were reasonable and prudent. The Commission also concludes that Frontier should file an additional schedule in its future annual review proceedings in a format comparable to Poole Exhibit 1 that reflects the results of its hedging program and should take the actions regarding its hedging program as recommended by Public Staff witness Farmer.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12 - 15

The evidence for these findings of fact is contained in the testimony of Frontier witness Shipley and Public Staff witness Larsen. No other party filed testimony or presented evidence on these matters.

Frontier witness Shipley testified that Frontier's gas supply policy is best described as a "best evaluated costs" supply strategy. This strategy is based upon the following criteria: (1) flexibility, (2) security/credit worthiness, (3) reliability of supply, (4) the cost of the gas, and (5) the quality of supplier customer service. Witness Shipley stated that the foremost criteria for the Company are flexibility, security/credit worthiness, and reliability of supply.

Witness Shipley stated that flexibility is required because of the daily changes in Frontier's market requirements caused by the unpredictable nature of the weather, the production levels/operating schedules of Frontier's industrial customers, the industrial customers' option to switch to alternative fuels, and the customer growth during the test period. While Frontier's gas supply agreements have different purchase commitments and swing capabilities (i.e., the ability to adjust purchase volumes within the contract volume), the gas supply portfolio as a whole must be capable of handling the seasonal, monthly, daily, and hourly changes in Frontier's market conditions.

Witness Shipley testified that Frontier understands the necessity of having security of supply to provide reliable and dependable natural gas service and has demonstrated its ability to do so. Frontier's gas supply strategy and its contract implementing this strategy have allowed Frontier to accomplish its objective.

Witness Shipley testified that the Company owns no interstate capacity and, therefore, has entered into a contract with BP Energy, a wholesale gas supplier with interstate capacity, to acquire all of its natural gas requirements in order to accomplish the above-mentioned objectives and to implement its strategy during the review period. This source of capacity has proven reliable even during the coldest peak winter days. The gas supply contract that Frontier has negotiated has the flexibility and reliability to meet its market requirements in a secure and cost effective manner, and Frontier evaluates and plans to meet future short-term and long-term requirements.

Frontier witness Shipley also testified that Frontier continues to incorporate a three part pricing strategy to help establish price stability and reduce risk to customers. Frontier's gas supply strategy is to hedge 25-60% of the forecasted volumes, to purchase 40-60% on a monthly basis, and to purchase 0-20% on a daily basis to reduce the risk and volatility in commodity gas pricing while also providing flexibility to take advantage of competitive pricing opportunities that may occur.

Public Staff witness Larsen testified that even though the scope of Commission Rule R1-17(k) is limited to a historical review period, he considered information received by the data request pertaining to Frontier's anticipated requirements for future needs, including design day estimates, forecasted gas supply needs, projection of capacity additions and supply changes, and customer load profile changes.

Public Staff witness Larsen testified that Frontier is still considered a relatively new company that began construction of its natural gas transmission and distribution systems in 1998 and completed construction of its transmission system in 2002. Witness Larsen testified that the construction of distribution pipelines and provisions for service for new customers continues in all six franchised counties. Witness Larsen further testified that during the review period, Frontier experienced a very high customer growth rate, at nearly 30%, which is approximately ten times the growth rate of legacy LDCs in North Carolina. Witness Larsen further testified that Frontier saw a substantial increase in agricultural load.

Witness Larsen also stated that Frontier does not have any capacity/storage services directly with interstate pipelines or storage facilities and, instead, provides service to its customers by purchasing gas from BP Energy. Given Frontier's size and profile since its beginning, witness Larsen further stated that it would have been expensive for Frontier to enter firm long-term capacity contracts similar to those used by the mature LDCs.

Based upon his investigation and review of the data filed in this docket, Public Staff witness Larsen testified that Frontier's gas costs during the review period were prudently incurred.

Based on the foregoing, the Commission concludes that Frontier's gas supply policies and practices, including its decision to lock in a gas supply for an entire year and its decision to implement a three-part purchasing approach to help establish price stability and reduce risk to the customer, were reasonable and prudent. The Commission further concludes that the gas costs incurred by Frontier during the review period were reasonable and prudent and should be recovered.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

The evidence for this finding of fact is contained in the testimony of Public Staff witness Larsen and Frontier witness Shipley. No other party filed testimony or presented evidence on these matters.

While Public Staff witness Larsen testified that, as of the end of the review period, Frontier showed a credit balance in its Deferred Gas Cost Account of $187,432 (owed from

Company to customers), he recommended no action be taken regarding the implementation of a temporary rate decrement. Witness Larsen further testified that the reasons for his recommendation are (1) the Company has proactively reduced rates for its customers and has already, in effect, implemented a rate decrement by keeping its benchmark cost of gas below the market [witness Larsen also noted that Frontier's Deferred Gas Cost Account balance was a credit balance of approximately $87,000 at the end of December 2009, and was anticipated to have "flipped" and become a debit balance (owed from the customers to the Company) of approximately $62,000 by the end of February 2010]; (2) Frontier is planning to file a Purchased Gas Adjustment (PGA) in the near future for March 1, 2010 implementation in order to more accurately track its cost of gas and to keep the Deferred Gas Cost Account from growing into an even higher debit balance; (3) if a decrement was implemented, the additional administrative burdens and costs imposed on a small LDC, such as Frontier, would be significant and should be considered; and (4) in Docket No. G-9, Sub 528, the Commission stated that G.S. 62-133.4(c) "requires the utility to refund over-recovery by credit or rate decrement, and the Commission concludes that such refund must be ordered when an over-recovery exists <u>and when any party insists that a refund be made</u>...." (emphasis added) Witness Larsen testified that no party has insisted in this proceeding that such a refund be made.

Frontier witness Shipley testified that Frontier's attentiveness to the commodity market and adjustments of its benchmark rates continue to result in a reasonable Deferred Gas Cost Account balance this year. Witness Shipley further testified that Frontier expects the Deferred Gas Cost Account balance at the end of the review period to re-adjust as the Company enters the winter strip period (November through March), which should bring the balance closer to zero.

The Commission notes Frontier's recent PGA filing in Docket No. G-40, Sub 92, where Frontier requested, and the Commission approved, an increase in its rates, effective March 1, 2010, that more accurately tracks Frontier's cost of gas. The Commission also agrees with the Public Staff's reasoning for not recommending implementation of a temporary rate decrement, due to the additional administrative burdens and costs imposed on a small LDC and since the most recent Deferred Gas Cost Account balance indicates that a rate decrement would be counter-productive at this time. The Commission also notes that, unlike the situation in Docket No. G-9, Sub 528, no party is insisting upon a rate adjustment being ordered in this proceeding. The Commission, therefore, concludes that it is appropriate not to require Frontier to implement a rate decrement at this time.

IT IS, THEREFORE, ORDERED as follows:

1. That Frontier's accounting for gas costs during the twelve months ended September 30, 2009, is approved;

2. That Frontier is authorized to recover 100% of its gas costs incurred during the twelve months ended September 30, 2009;

3. That Frontier shall file an additional schedule in future annual review of gas costs proceedings comparable to Poole Exhibit 1; and

4. That Frontier shall take the following actions regarding its hedging program: (a) develop full documentation of its hedging program that includes strategy, goals, authorizations, responsibilities, sources of information used, reporting, etc.; (b) retain all documentation from all sources that supports the decision-making for each hedge or block of hedges executed in the future; (c) discuss any plans for financial hedging with the Public Staff well in advance if the Company believes it may be a viable option in the future; and (d) continue to evaluate its hedging program, implement improvements as feasible, and continue the dialogue regarding hedging activities with the Public Staff and the Commission.

ISSUED BY ORDER OF THE COMMISSION.
This the 31st day of March, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Patricia Swenson, Deputy Clerk

kh033110.01

DOCKET NO. G-41, SUB 30

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Toccoa Natural Gas 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, November 9, 2010, at 10:00 a.m., in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner Bryan E. Beatty, Presiding; Commissioners ToNola D. Brown-Bland and Lucy T. Allen

APPEARANCES:

For Toccoa Natural Gas:

Karen M. Kemerait, Styers & Kemerait, 1101 Haynes Street, Suite 101, Raleigh, North Carolina 27604

For the Using and Consuming Public:

Tab C. Hunter, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

NATURAL GAS – ADJUSTMENT OF RATES/CHARGES

BY THE COMMISSION: On August 30, 2010, Toccoa Natural Gas (Toccoa or Company) filed the direct testimony and exhibits of Rai Trippe, Member Support Senior Business Analyst for the Municipal Gas Authority of Georgia (Gas Authority), and Donald Dye, Utilities Director for Toccoa Natural Gas, a division of the City of Toccoa, Georgia, in connection with the annual review of Toccoa's gas costs pursuant to G.S. 62-133.4(c) and Commission Rule R1-17(k)(6), for the twelve-month period ended June 30, 2010.

On September 13, 2010, the Commission issued its Order Scheduling Hearing, Establishing Filing Dates and Discovery Guidelines, and Requiring Public Notice. This Order established a hearing date of November 9, 2010, set prefiled testimony dates, and required Toccoa to give at least 30 days prior notice to its customers of the hearing on this matter.

On September 14, 2010, the Commission issued its Errata Order correcting the time for the November 9, 2010 hearing to 10:00 a.m.

On October 1, 2010, Toccoa filed a revised Schedule 5 to the testimony and exhibits of Rai Trippe.

On October 25, 2010, the Public Staff filed the affidavit of Thomas W. Farmer, Jr., Director, Economic Research Division, and the testimony of David A. Poole, Staff Accountant, Natural Gas Section, Accounting Division, and Richard C. Ross, Utilities Engineer, Natural Gas Division.

No other party filed testimony in this docket.

On October 28, 2010, Toccoa filed Affidavits of Publication of Notice.

On November 1, 2010, Toccoa filed a Consent Motion for Leave to Have Annual Review Testimony Entered into the Record and its Exhibits Admitted into Evidence (Consent Motion). Toccoa's Consent Motion stated that the Company and the Public Staff had reached an agreement on all issues in the docket and requested that the prefiled direct testimony of witnesses be admitted into evidence without the need for them to appear at the hearing.

On November 3, 2010, the Public Staff filed a corrected page 5 of the testimony of Richard C. Ross.

On November 5, 2010, the Commission issued its Order Granting the Consent Motion.

On November 9, 2010, the matter came on for hearing as scheduled.

Pursuant to the agreement of all parties of record, the prefiled testimony and exhibits of the Company witnesses and the prefiled affidavit, testimony, and exhibits of the Public Staff affiant and witnesses were introduced and admitted into evidence and the parties waived cross examination. No public witnesses appeared at the hearing.

Based on the testimony, exhibits, and the entire record in this proceeding, the Commission makes the following:

FINDINGS OF FACT

1. Toccoa Natural Gas, a division of the City of Toccoa, Georgia, is a public utility as defined by G.S. 62-3(23), subject to the jurisdiction of the Commission.

2. Toccoa is primarily engaged in the business of purchasing, transporting, distributing, and selling natural gas to approximately 6,700 customers in Georgia and North Carolina.

3. The Company has filed with the Commission and submitted to the Public Staff all information required by G.S. 62-133.4(c) and Commission Rule R1-17(k) and has complied with the procedural requirements of such statute and rule.

4. The review period in this proceeding is the twelve months ended June 30, 2010.

5. During the review period, Toccoa incurred total North Carolina gas costs of $560,570, which was composed of $127,254 of demand and storage costs, $373,508 of commodity costs, and $59,809 of other gas costs.

6. At June 30, 2010, Toccoa had a debit balance of $63,040, owed to Toccoa, in its North Carolina Deferred Gas Cost Account (NC Deferred Account).

7. Toccoa properly accounted for its gas costs during the review period except for the Public Staff adjustment related to the increment and decrement entries in its NC Deferred Account. The Company agreed with this adjustment.

8. Toccoa's hedging activities during the review period were reasonable and prudent.

9. Toccoa has transportation and storage contracts with interstate pipelines that provide for the transportation of gas to Toccoa's system and an "all requirements" gas supply contract with the Gas Authority.

10. Toccoa released unutilized capacity during the review period to mitigate the cost of extra demand capacity, and all margins earned on secondary market transactions reduced the cost of gas and were flowed through to ratepayers.

11. Toccoa has adopted a "portfolio approach" gas purchasing policy that consists of four main components: long-term firm supply, short-term spot market purchases, seasonal peaking, and contract storage services.

12. Toccoa's gas purchasing policies and practices during the review period were prudent, and its gas costs during the review period were prudently incurred.

13. Toccoa should be permitted to recover 100% of its prudently incurred gas costs.

14. As a result of this proceeding, the Company should implement the temporary rate increment of $0.8353 per dekatherm (/dt) proposed by Public Staff witness Ross.

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

These findings are essentially informational, procedural, or jurisdictional and are based on evidence uncontested by any of the parties. The evidence supporting these findings is contained in the official files and records of the Commission and in the testimony and exhibits of Toccoa witnesses Trippe and Dye.

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

The evidence supporting these findings of fact is contained in the testimony of Toccoa witness Trippe, the testimony of Public Staff witnesses Ross and Poole, and the provisions of G.S. 62-133.4(c) and Commission Rule R1-17(k)(6).

G.S. 62-133.4(c) requires that each natural gas utility submit to the Commission information and data for a historical 12-month review period concerning its actual cost of gas, volumes of purchased gas, sales volumes, negotiated sales volumes, and transportation volumes. Commission Rule R1-17(k)(6)(c) requires the filing by Toccoa of certain information and data showing weather-normalized sales volumes, work papers, and direct testimony and exhibits supporting the information.

Toccoa witness Trippe testified that he was not aware of any outstanding issues regarding the reporting requirements of Commission Rule R1-17(k)(5)(c), which requires the Company to file a complete monthly accounting of computations under the provisions of the Rule for gas costs and deferred account activity.

Public Staff witnesses Ross and Poole confirmed that the Public Staff had reviewed the filings and monthly reports filed by Toccoa. No other party filed testimony or presented evidence on this matter.

The Commission, therefore, concludes that Toccoa has complied with all procedural requirements of G.S. 62-133.4(c) and Commission Rule R1-17(k) for the review period.

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

The evidence supporting these findings of fact is contained in the testimony of Toccoa witness Trippe and Public Staff witness Poole. No other party filed testimony or presented evidence on these matters.

Toccoa witness Trippe's testimony, exhibit, and revised schedules show that Toccoa incurred total North Carolina gas costs of $560,570. Witness Trippe's Schedule 1 reflects $127,254 of demand and storage costs, $373,508 of commodity costs, and $59,809 of other gas costs. Public Staff witness Poole testified that every month the Public Staff reviews the NC Deferred Account reports filed by Toccoa for accuracy and reasonableness and performs audit procedures on the calculations.

Witness Poole testified that Toccoa had properly accounted for its gas costs during the review period except for the adjustment related to the increment and decrement entries. Witness Poole testified that he made an adjustment to correct the sign on the entries for Toccoa's temporary rate increment activity recorded in the NC Deferred Account. He stated that the signs were inadvertently reversed during the current review period and that the Company agreed with this adjustment.

Public Staff witness Poole further testified that, as of June 30, 2010, Toccoa's NC Deferred Account had a debit balance of $63,040, owed to Toccoa, compared to the prior period ending balance of $20,338, owed to Toccoa. The $42,702 increase in Toccoa's NC Deferred Account consists of the following deferred account activity: Commodity and Demand Gas Cost True-up of ($3,026), Firm Hedges of $59,809, and Increment activity of ($14,081).

Based on the foregoing, the monthly filings by Toccoa pursuant to Commission Rule R1-17(k)(5)(c), and the findings and conclusions set forth above, the Commission concludes that Toccoa has properly accounted for its gas costs incurred during the review period and that Toccoa's NC Deferred Account balance as proposed by the Public Staff and reflected in the Company's revised exhibits is correct.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence supporting this finding of fact is contained in the testimony of Toccoa witness Trippe and Public Staff witness Poole and the Affidavit of Public Staff affiant Farmer.

Company witness Trippe stated that, although hedging helps manage volatility in the wholesale cost of gas, it can create its own challenges. Some customers have unrealistic expectations of the benefits of hedging, because a common benchmark for evaluating hedged prices is the actual spot market price. Witness Trippe further stated that this can be an unfair measure because it is only available after the fact, and it assumes that the goal of hedging is "to beat the market." He continues to state that the goal of hedging is to achieve price stability, at a reasonable level, for the consuming public.

Company witness Trippe further testified that Toccoa participates in the Gas Authority's "WinterHedge" program under the Authority's Option 2. The Gas Authority's objective in hedging prices is to achieve price stability at a reasonable level for its members' retail customers. This is accomplished by locking-in futures prices on approximately 50% of Toccoa's firm load (based on normal weather) for the months of October through March each winter.

Public Staff affiant Farmer testified that Toccoa participates in the "Winter Hedge Program," which is managed by the Gas Authority for its members. Witness Farmer further stated in his affidavit that during the review period, the hedging program resulted in a net increase in North Carolina gas costs of $59,809. Based on his review, witness Farmer stated that Toccoa's hedging activities were reasonable and prudent.

Based on the testimony presented by the Company and the Public Staff, the Commission concludes that the Company's hedging activities during the review period were reasonable and prudent.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 9-14

The evidence for these findings of fact is contained in the testimony of Toccoa witness Trippe and Public Staff witness Ross. No other party filed testimony or presented evidence on these matters.

Toccoa witness Trippe testified that Toccoa is a charter member of the Gas Authority, which supplies its member cities' needs, relying on a combination of long-term firm supply arrangements, short-term spot market purchases, seasonal peaking, and contract storage services. He also testified that Toccoa is assured adequate, dependable, and economical gas supplies through the Gas Authority's efforts.

Public Staff witness Ross testified that Toccoa has eight contracts for pipeline capacity and storage service from Transco, a storage service contract with Pine Needle, and a gas supply contract with the Gas Authority. Based upon his investigation and review of the data filed in this docket, Public Staff witness Ross testified that Toccoa's gas costs during the review period were prudently incurred.

Toccoa witness Trippe testified that, as a member of the Gas Authority, Toccoa receives all of its gas supply at very competitive rates. The Gas Authority uses a portfolio approach to supply its member cities' needs relying on a combination of long-term firm supply arrangements, short-term spot market purchases, seasonal peaking, and contract storage services.

Toccoa witness Trippe further testified that the Gas Authority, on behalf of Toccoa, was able to release a portion of Toccoa's unutilized capacity each month of the fiscal period.

Public Staff witness Ross testified that Toccoa secures its gas supply at monthly index market prices.

Based on the June 30, 2010 debit balance in Toccoa's NC Deferred Account of $63,040, witness Ross proposed a temporary rate increment of $0.8353/dt for all North Carolina firm customers, which will replace the current increment of $0.2946/dt. Witness Ross further testified that the recommended increment is based on this review period's firm sales volumes of 75,470 dts, rather than using volumes determined in a most recent general rate case since Toccoa has never had a general rate case.

No other party filed testimony or 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. The Commission, further, concludes that a temporary rate increment is appropriate and should be implemented as recommended by Public Staff witness Ross.

IT IS, THEREFORE, ORDERED:

1. That Toccoa's accounting for gas costs for the twelve-month period ended June 30, 2010, is approved;

2. That the gas costs incurred by Toccoa during the twelve-month period ended June 30, 2010, were reasonably and prudently incurred, and that Toccoa is authorized to recover 100% of its gas costs as provided herein;

3. That Toccoa shall remove the existing temporary rate increment that was implemented in Toccoa's previous Annual Review of Gas Costs proceeding and implement the temporary rate increment proposed by Public Staff witness Ross in the instant docket, effective the first day of the month following the date of this order; and

4. That Toccoa shall give notice to its customers of the rate changes allowed in this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 10th day of December, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

kh120910.01

DOCKET NO. G-5, SUB 508
DOCKET NO. G-23, SUB 2
DOCKET NO. G-5, SUB 510

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-5, SUB 508 DOCKET NO. G-23, SUB 2 In the Matter of Piedmont Natural Gas Company, Inc. v. Public Service Company of North Carolina, Inc., and the City of Monroe DOCKET NO. G-5, SUB 510 In the Matter of Application of Public Service Company of North Carolina, Inc., for Authority to Operate Pipeline Facilities in Cabarrus and Iredell Counties	ORDER ALLOWING JOINT MOTION FOR APPROVAL OF SETTLEMENT AND ABANDONMENT OF SERVICE

BEFORE: Commissioner Lorinzo L. Joyner, Presiding; Chairman Edward S. Finley, Jr.; and Commissioner Bryan E. Beatty

BY THE COMMISSION: On May 6, 2009, Piedmont Natural Gas Company, Inc. (Piedmont), filed a complaint with the North Carolina Utilities Commission (Commission) against Public Service Company of North Carolina, Inc. (PSNC), in Docket No. G-5, Sub 508. The complaint concerns a Joint Venture Agreement and related agreements entered into by PSNC and the City of Monroe (Monroe) setting forth their respective roles, rights, and obligations in designing, constructing, owning, and operating a proposed natural gas pipeline (Monroe Pipeline) that will cross Union, Cabarrus, and Iredell Counties and will connect Monroe's distribution facilities (and potentially future facilities of the City of Mooresville and the Town of Midland) to the interstate pipeline facilities of Transcontinental Gas Pipe Line Company, LLC. The complaint alleged four claims: (1) violation of Piedmont's exclusive service territory rights in Union County, (2) violation of Commission Rule R6-60, (3) violation of Commission Rule R6-61, and (4) violation of Commission Rule R6-62.

On May 26, 2009, PSNC filed a Motion to Dismiss and Answer to Complaint. PSNC moved to dismiss each of the claims in the complaint for failure to state a claim.

On June 2, 2009, PSNC filed an Application in Docket No. G-5, Sub 510. This application sought Commission approval, pursuant to Commission Rule R6-61, to participate in the operation of the Monroe Pipeline facilities in Cabarrus and Iredell Counties.

An oral argument on Piedmont's request for preliminary injunctive relief was held in the Sub 508 docket on June 3, 2009. On June 15, 2009, the Commission issued a Preliminary Injunction enjoining PSNC from engaging in any further acts designed to assist or facilitate Monroe's efforts to design, construct, install, or operate natural gas transmission and distribution facilities within Union County.

On June 17, 2009, Piedmont filed an Amendment to Complaint in the Sub 508 docket and new Docket No. G-23, Sub 2, which added Monroe as a respondent and asserted an additional claim. In this new claim, Piedmont alleged that the Monroe Pipeline is a jurisdictional intrastate natural gas pipeline subject to the general regulatory jurisdiction of the Commission and that Monroe and PSNC's activities in connection with the Monroe Pipeline subject Monroe and PSNC to the jurisdiction of the Commission as public utilities and the requirements of Chapter 62 of the North Carolina General Statutes.

On that same day, June 17, 2009, Piedmont filed a Petition to Intervene, Protest, and Motion to Consolidate Proceedings. The Presiding Commissioner subsequently allowed Piedmont to intervene in the Sub 510 docket.

Answers to the amendment of Piedmont were filed by Monroe on July 6, 2009, and by PSNC on July 7, 2009. Monroe moved to dismiss the amendment on grounds that Monroe is not subject to regulation by the Commission and the amendment fails to state a claim.

The Commission conducted an oral argument and subsequently issued an order on September 3, 2009, that denied the motion filed by PSNC to dismiss the complaint and the motion filed by Monroe to dismiss the amendment to the complaint, allowed the motion to consolidate filed by Piedmont, scheduled an evidentiary hearing, and asked the Public Staff to participate.

On October 9, 2009, Piedmont filed a motion requesting temporary suspension of the proceedings in these dockets in order to allow the parties to pursue settlement discussions. This motion was allowed by Order of October 9, 2009. Following extensive discussions, Piedmont, PSNC, Monroe, and the Public Staff reached a resolution of the matters pending in these proceedings and executed a Settlement Agreement.

On May 7, 2010, Piedmont, PSNC, and the Public Staff filed a Joint Motion for Approval of Settlement and Abandonment of Service in the above-captioned dockets seeking (1) approval of the Settlement Agreement and (2) authorization for Piedmont to abandon service to Monroe.[1]

As to the first request for relief, the terms of the settlement are set forth in the Settlement Agreement which was attached to the Joint Motion and incorporated by reference. Piedmont,

[1] Monroe did not join in the Joint Motion consistent with its position that, as a North Carolina municipality, it is exempt from the Commission's jurisdiction; however, Monroe is a party to the Settlement Agreement.

PSNC, and the Public Staff state that the Settlement Agreement is in the public interest and that it resolves the disputes among the parties, including disputes relating to the Commission's jurisdiction over the Monroe Pipeline, in a manner that is both acceptable to the parties and not harmful to the Commission's jurisdiction. They further submit that the resolution of disputes set forth in the Settlement Agreement allows for the efficient utilization of pipeline facilities that have been largely constructed using public funds, is in the public interest and consistent with state law and Commission policy, and will terminate expensive and time-consuming litigation both before the Commission and the Union County Superior Court.

The Commission has reviewed the Settlement Agreement. The Settlement Agreement provides, among other things, (a) that Monroe and PSNC will amend their Joint Venture Agreement to eliminate PSNC's ownership interest in the Monroe Pipeline and to provide that the pipeline will be a purely municipal enterprise; (b) that PSNC may connect to the Monroe Pipeline and purchase capacity on it to facilitate service by PSNC to end use customers in its certificated service territory; (c) that Monroe will be responsible for all maintenance, operations, and safety/emergency response functions for the Monroe Pipeline, either through municipal resources or through contracts with third-parties, provided that any such contract with a North Carolina certificated LDC will be limited to pipeline safety activities; (d) that the Monroe Pipeline will be used only for the wholesale transportation of natural gas to the local distribution systems of Monroe, Mooresville, Midland, PSNC, and, potentially, Piedmont; (e) that Monroe will sell and Piedmont will purchase the four-inch distribution facilities that were constructed by Monroe north of Lawyers Road in Union County in conjunction with the Monroe Pipeline; and (f) that Piedmont and PSNC will dismiss or withdraw the proceedings before the Commission in these dockets and other litigation in Union County Superior Court. The performance of the specific obligations in the Settlement Agreement is not due until the Effective Date, which is the date of Commission approval of the Settlement Agreement without material modification. The Settlement Agreement provides that neither it nor any Commission order approving it shall have precedential value in future proceedings.

The Commission finds good cause to allow the Joint Motion and to approve the Settlement Agreement as just and reasonable and in the public interest for the purpose of authorizing the parties to carry out their specific obligations set forth in the Settlement Agreement and to resolve and conclude the proceedings in these dockets. This approval is without prejudice and without precedent to other, future proceedings, including ratemaking proceedings.

As to the second request for relief, Monroe is an existing customer of Piedmont, and Piedmont asserts that, upon the Monroe Pipeline being placed into service, Monroe will no longer require direct service from Piedmont and that G.S. 62-118 requires Commission approval for Piedmont to abandon service to Monroe. The Settlement Agreement provides that Piedmont may abandon service to Monroe subject to the commitment by Piedmont to provide Emergency Service to Monroe on the conditions specified in the Settlement Agreement.

G.S. 62-118 provides that the Commission, after petition and notice and upon finding that public convenience and necessity are no longer served, may authorize any public utility to abandon or reduce service. The Commission concludes that the Joint Motion serves as such a petition; that Monroe, the customer affected, has notice and has agreed to the abandonment of service from Piedmont; and that, upon the Monroe Pipeline being placed into service, the public convenience and necessity no longer require direct service by Piedmont to Monroe. The Commission finds good cause to allow the Joint Motion and to approve the abandonment of service by Piedmont to Monroe on the terms and conditions set forth in the Settlement Agreement.

IT IS, THEREFORE, ORDERED that the Joint Motion for Approval of Settlement and Abandonment of Service filed in these dockets by Piedmont, PSNC, and the Public Staff on May 7, 2010, should be, and hereby is, allowed as hereinabove provided.

ISSUED BY ORDER OF THE COMMISSION.
This the 18th day of May, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Sk051810.01

DOCKET NO. G-59, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Petition of Rivermill Village LLC for	)	ORDER APPROVING NATURAL
Approval of Natural Gas Master Metering	)	GAS MASTER METERING PLAN
Plan for the Rivermill Residential Lofts	)	

BY THE COMMISSION: On August 23, 2010, Rivermill Village LLC (Applicant) filed a letter pursuant to G.S. 143-151.42 requesting that the Commission approve a natural gas metering plan for the Rivermill Residential Lofts at Saxapahaw Rivermill, a development project located at 1715 Saxapahaw-Bethlehem Church Road, Saxapahaw, North Carolina. The full development is a conversion of a 1950s textile mill and includes separate commercial and residential buildings. The residential building consists of twenty-nine residential loft units, a residents' common room, and associated circulation, storage, and mechanical spaces. Construction began in February 2010 and is expected to be completed in May 2011.

Included in the filing were descriptions of the proposed central solar-assisted hot water, the HVAC system, and the metering plan for the project. According to the information provided, one master meter will include both the central solar-assisted hot water system and natural gas ranges. The heating and cooling for all residential units and common spaces will be provided by individual water source heat pumps utilizing a common geothermal loop that will not require any mechanical tempering. The HVAC system, therefore, was not included in the master meter request.

Attached to the filing was a letter dated August 16, 2010, from Sud Associates, P.A., and signed by Michael E. Saenger, who is a Professional Engineer registered in North Carolina. This letter detailed the energy efficiency of the central solar-assisted hot water system. The proposed central hot water system will consist of twenty 4' by 10' flat plate solar collectors heating a 1000 gallon storage tank through a heat exchanger; it will be backed up by a pair of 94% efficient gas water heaters. The solar hot water system is expected to provide on average over 80% of the domestic hot water usage. According to the information provided, when compared to the energy requirements of a system using distributed 82% efficient gas water heaters, the proposed central solar-assisted system will save over 2000 therms annually, and will result in an 82.9% reduction in energy consumption.

The Public Staff presented this matter at the September 13, 2010, Staff Conference. The Public Staff stated that it had reviewed the request and recommended that the proposed natural gas master metering plan be approved.

Based on the foregoing, the Commission concludes that the request of Rivermill Village LLC should be granted.

IT IS, THEREFORE, SO ORDERED.
This the 16th day of September, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Patricia Swenson, Deputy Clerk

Pb091510.02

RENEWABLE ENERGY THERMAL – FILINGS DUE PER ORDER OR RULE

DOCKET NO. RET-10, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	
Application of North Mecklenburg Aquatics d/b/a Nomad Aquatics & Fitness for Registration of a New Renewable Energy Facility	) ORDER ACCEPTING) REGISTRATION OF NEW) RENEWABLE ENERGY FACILITY)

BY THE CHAIRMAN: On March 11, 2010, and April 21, 2010, North Mecklenburg Aquatics d/b/a Nomad Aquatics & Fitness (Nomad) filed a registration statement pursuant to Commission Rule R8-66 for a solar thermal hot water heating facility located in Huntersville in Mecklenburg County, North Carolina. Nomad's registration statement described its facility as consisting of 169 4x12 solar panels used to produce heat for two commercial swimming pools. Nomad stated that the solar thermal hot water heating facility became operational in January, 2007. In its March 11, 2010 filing, Nomad stated that it does not have any Btu monitoring devices, although it does continuously monitor the temperature of the pools, and requested that it be allowed to earn 429.45 renewable energy certificates (RECs) per year for 2008 and 2009 based upon the capacity of its solar panels.

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) Nomad will not remarket or otherwise resell any RECs sold to an electric power supplier to comply with G.S. 62-133.8; and 4) Nomad 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 April 1, 2010, the Public Staff filed a letter with the Commission noting that Nomad had requested that it be allowed to earn RECs from past, unmetered thermal generation and recommending that such RECs should not be allowed without a more rigorous analysis. On May 17, 2010, the Public Staff filed the recommendation required by Commission Rule R8-66, stating that Nomad's registration statement as a new renewable energy facility should be considered to be complete. The Public Staff noted that some metering exists at the pool, but that the metering is not sufficient to calculate the Btu generated by the solar thermal system. Therefore, based on its review of supplemental information provided by Nomad, the Public Staff recommended that Nomad should be allowed to earn 236 RECs per year for past years based upon an engineering analysis of the energy from the solar thermal system actually required to heat the pools. Lastly, the Public Staff stated that it does not believe that the cost of a Btu meter should be prohibitive for this system, and recommended that any RECs claimed after the date of the final order in this matter must be calculated using a Btu meter. No other party made a filing with respect to these issues.

RENEWABLE ENERGY THERMAL – FILINGS DUE PER ORDER OR RULE

On June 10, 2010, Nomad filed a letter stating that it agreed with the Public Staff's calculation regarding the number of RECs earned from past operation of the solar thermal facility.

Based upon the foregoing and the entire record in this proceeding, the Chairman finds good cause to accept registration of the facility as a new renewable energy facility. G.S. 62-133.8(a) defines a renewable energy facility to include "a solar thermal energy facility" and a new renewable energy facility to include a renewable energy facility that was "placed into service on or after January 1, 2007." G.S. 62-133.8(a) further provides that a REC is "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 ...." Commission Rule R8-67(g)(4) provides as follows:

> 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. The useful thermal energy may be measured by meter, or if that is not practicable, by other industry-accepted means that show what measurable amount of useful thermal energy the system or facility is designed and operated to produce and use. Renewable energy certificates shall be earned based on one megawatt-hour for every 3,412,000 British thermal units of useful thermal energy produced.

Although Btu metering is preferable, especially on a large system, Rule R8-67(g)(4) does not require that a solar thermal facility be metered in order to earn RECs. A solar thermal facility must be metered, however, in order for any RECs earned to be eligible to be used to meet the solar set-aside requirement of G.S. 62-133.8(d) ("For calendar year 2018 and for each calendar year thereafter, at least two-tenths of one percent (0.2%) of the total electric power in kilowatt hours sold to retail electric customers in the State, or an equivalent amount of energy, shall be supplied by a combination of new solar electric facilities and new <u>metered</u> solar thermal energy facilities ...." (Emphasis added.))

The Chairman, therefore, finds good cause to allow Nomad to earn RECs based upon an engineering analysis of the energy from the solar thermal system actually required to heat the pools. Given the facts alleged in this proceeding, including the statements regarding the operation of the solar thermal facility and the pools at the aquatic center, Nomad has earned between 33 and 34 unmetered solar thermal RECs per month during the months of April through October since 2008. However, Nomad must install appropriate Btu metering before subsequent RECs earned will be eligible to meet the solar set-aside requirement. Nomad shall annually file the information required by Commission Rule R8-66 on or before April 1 of each year. Lastly, Nomad will be required to participate in the NC-RETS REC tracking system and regularly provide production information to the tracking system in order to facilitate the issuance of RECs.

IT IS, THEREFORE, ORDERED as follows:

1. That the registration by Nomad for its solar thermal hot water heating facility located in Huntersville in Mecklenburg County, North Carolina, as a new renewable energy facility shall be, and hereby is, accepted.

2. That Nomad 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 21st day of July, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Patricia Swenson, Deputy Clerk

Sw072110.01

DOCKET NO. RET-10, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	
Application of North Mecklenburg Aquatics d/b/a Nomad Aquatics & Fitness for Registration of a New Renewable Energy Facility	) ORDER DENYING REQUEST TO) INCREASE NUMBER OF RECS) EARNED)

BY THE CHAIRMAN: On March 11, 2010, and April 21, 2010, North Mecklenburg Aquatics d/b/a Nomad Aquatics & Fitness (Nomad) filed a registration statement pursuant to Commission Rule R8-66 for a solar thermal hot water heating facility located in Huntersville in Mecklenburg County, North Carolina. Nomad's registration statement described its facility as consisting of 169 4x12 solar panels used to produce heat for two commercial swimming pools. Nomad stated that the solar thermal hot water heating facility became operational in January, 2007. In its March 11, 2010 filing, Nomad stated that it does not have any Btu monitoring devices, although it does continuously monitor the temperature of the pools, and requested that it be allowed to earn 429.45 renewable energy certificates (RECs) per year for 2008 and 2009 based upon the capacity of its solar panels.

In its letter filed May 17, 2010, the Public Staff noted that some metering existed at the pool, but that the metering was not sufficient to calculate the Btus generated by the solar thermal system. Therefore, based on its review of supplemental information provided by Nomad, the Public Staff recommended that Nomad should be allowed to earn 236 RECs per year for past years based upon an engineering analysis of the energy from the solar thermal system actually required to heat the pools performed by Aqua Therm, the system designer.

RENEWABLE ENERGY THERMAL – FILINGS DUE PER ORDER OR RULE

On June 10, 2010, Nomad filed a letter stating that it agreed with the Public Staff's calculation regarding the number of RECs earned from past operation of the solar thermal facility.

On July 21, 2010, the Commission issued an Order accepting registration of Nomad's solar thermal facility as a new renewable energy facility and allowing Nomad to earn RECs based upon the engineering analysis. In its Order, the Commission concluded that a solar thermal facility must be metered in order for any RECs earned to be eligible to be used to meet the solar set-aside requirement of G.S. 62-133.8(d). The Commission found that, given the facts alleged in this proceeding, including the statements regarding the operation of the solar thermal facility and the pools at the aquatic center, Nomad had earned between 33 and 34 unmetered solar thermal RECs per month during the months of April through October since 2008. Lastly, the Commission stated that Nomad must install appropriate Btu metering before subsequent RECs earned will be eligible to meet the solar set-aside requirement.

On October 27, 2010, Nomad filed a letter providing additional information and requesting an increase in the number of RECs earned since 2008.[1] Nomad stated that it had operated the solar thermal system without using Btu measuring devices through the end of August 2010, but that it has now implemented Btu metering systems which went into operation on September 1, 2010. Nomad further stated that the previous estimate of Btus used and RECs earned was too low; its new measurements determined that the system produced 80.4 RECs in September and 53.8 RECs for the first two weeks of October. Nomad, therefore, requested that the Commission approve an increase in the number of RECs previously earned from 236 to 609 per year, or 87 per month for the seven operating months of each year, to more accurately represent the production and demand rates of its solar thermal system, providing calculations of the minimum REC capacity of its solar thermal system and minimum REC demand of its pools in support of its request.

On November 15, 2010, the Public Staff filed a response to Nomad's request. In its response, the Public Staff stated that one of its engineers visited Nomad's facility and viewed the swimming pools, the solar water heating system, and Nomad's metering equipment. He found that Nomad had a portable flow meter and two thermometers, enabling it to measure the water and air temperature and the rate of circulation of water through the pool system at any given moment. However, Nomad had no equipment capable of recording temperature or flow data over the course of time, so as to allow a calculation of the total thermal energy produced by the system within a specified time period. The Public Staff advised Nomad that its current method should be improved to a true Btu meter that can continuously record flows and provide data for easier and more accurate determination of RECs.

The Public Staff further noted in its response that Nomad, in its October 27, 2010 letter, presented new measurements of water and air temperatures and water flow rates that result in

[1] As Mr. Steven G. Billings does not appear to be an attorney licensed to practice law in North Carolina, the Commission will consider Nomad's October 27, 2010 letter as additional information supporting its request for registration. Any motions or other pleadings, including reconsideration or appeal of the Commission's decision in this proceeding, should be filed by an attorney as required by G.S. 84-4 and Commission Rule R1-5(d).

more than twice the Btus and RECs than determined in the earlier engineering analysis by the system designer. However, Nomad did not offer any measurement of the total thermal energy produced by its system over a specified period of time. Nor did Nomad indicate that it has now obtained metering equipment capable of recording temperatures and flow rates on a continuous basis. The Public Staff stated that it cannot explain this difference in Btus except by again noting the lack of accuracy in Nomad's Btu metering. The Public Staff, therefore, recommended that the Commission deny Nomad's request and affirm the number of RECs previously found to be appropriate for Nomad's solar thermal system, stating that Nomad has failed to provide any valid basis for modifying the decision in the Commission's July 21, 2010 Order. The Public Staff further recommended that, if Nomad desires to begin earning RECs that qualify for the solar set-aside requirement or to be allowed a larger number of RECs for its operations since 2008, it should take the following steps: (a) provide confirmation that it has properly installed a continuously recording Btu metering system that can accurately measure and record Btu production over a continuous period rather than simply at a given instant; (b) provide data for an April 1 through October 31 time period from this Btu metering; and (c) provide all calculations of past REC creation, including spreadsheets with cell formulas.

After careful consideration, the Chairman finds good cause to deny Nomad's request based upon the Public Staff's investigation. The Chairman is not persuaded that Nomad has installed adequate Btu metering equipment or that the data provided in its October 27, 2010 letter is sufficient to support an increase in the number of RECs earned from 236 to 609 per year – more than two and one-half times the estimate provided in the engineering analysis performed by the system designer. The Chairman, therefore, affirms the findings and conclusions in his July 21, 2010 Order regarding the number of RECs earned by Nomad's solar thermal system since April 2008.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 10th day of December, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

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DOCKET NO. SP-297, SUB 1

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Orbit Energy, Inc., for Registration of a New Renewable Energy Facility	)) ORDER ACCEPTING) REGISTRATION OF NEW) RENEWABLE ENERGY FACILITY

BY THE CHAIRMAN: On January 29, 2010, Orbit Energy, Inc., (Orbit Energy), filed a registration statement pursuant to Commission Rule R8-66 for a new renewable energy facility located in Mecklenburg County, North Carolina. Orbit Energy's registration statement stated that its 3.2 MW facility is expected to begin operating on or about December 31, 2010. The facility will use anaerobic digestion to convert organic wastes, including food waste, vegetative waste from landscaping operations, paper and cardboard, agricultural and animal waste, and food processing waste, into biogas and compost. The biogas will fuel reciprocating engine generator sets to produce electricity from renewable resources. Orbit Energy intends to sell the electric power generated at this facility to Duke Energy Carolinas, LLC.

The filing included certified attestations that: 1) the facility will comply 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) Orbit Energy 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) Orbit Energy 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 19, 2010, the Public Staff filed the recommendation required by Rule R8-66(e) stating that Orbit Energy'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.

Based upon the foregoing and the entire record in this proceeding, including the source of fuel stated in the application, the Chairman finds good cause to accept registration of the facility as a new renewable energy facility. Although not specifically noted in paragraph (1)(xi) of the registration statement, Orbit Energy must still obtain a certificate of public convenience and necessity pursuant to G.S. 62-110.1(a) prior to beginning construction of the facility. Orbit Energy shall annually file the information required by Commission Rule R8-66 on or before April 1 of each year. Orbit Energy will be required to participate in the North Carolina REC tracking system in order to facilitate the issuance of RECs.

IT IS, THEREFORE, ORDERED as follows:

1. That the registration by Orbit Energy for its biogas facility located in Mecklenburg County, North Carolina, as a new renewable energy facility shall be, and hereby is, accepted.

2. That Orbit Energy 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 12th day of March, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Kc031210.01

DOCKET NO. SP-578, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	
Application of Green Energy Solutions NV, Inc., for Registration of a New Renewable Energy Facility	) ORDER ACCEPTING) REGISTRATION OF NEW) RENEWABLE ENERGY FACILITY

BY THE COMMISSION: On December 2, 2009, Green Energy Solutions NV, Inc., (GES) filed a registration statement pursuant to Commission Rule R8-66 for a 1.628-MW new renewable energy facility to be located in Darlington County, South Carolina. GES stated that the combined heat and power facility will generate electricity using methane gas produced via anaerobic digestion of poultry litter from the Collins Chick Farm. In email correspondence with the Public Staff, which was filed in this docket, GES stated that the waste heat from the electric generators will provide temperature control for the methane-producing anaerobic digester as well as the chicken houses at the Collins Chick Farm. GES stated that the facility is projected to come on line by the end of June 2010, provided that it timely obtains a power purchase agreement to sell its output.

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) GES 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) GES 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 December 11, 2009, the Public Staff filed the recommendation required by Commission Rule R8-66(e) stating that GES's registration statement should be considered to be complete. No other party made a filing with respect to these issues.

On January 8, 2010, GES filed a motion for clarification in Docket No. E-2, Sub 113. In that submittal, GES stated that, in its process, poultry waste is mixed with other organic, biodegradable materials, which are together digested to produce methane.

Based upon the foregoing and the entire record in this proceeding, including the sources of fuel stated in the registration statement and GES's January 8, 2010 submission in Docket No. E-100, Sub 113, the Commission finds good cause to accept registration of the facility as a new renewable energy facility. Contemporaneous with this Order, the Commission has issued an Order in Docket No. E-100, Sub 113 clarifying that only that portion of the energy generated from the biogas that is derived from poultry waste is eligible to earn RECs that may be used to meet the REPS poultry waste set-aside requirement. To support the issuance of RECs, GES, therefore, will be required to provide evidence as to how it will determine the percent of biogas attributable to the anaerobic digestion of poultry waste, versus the percent derived from other biomass sources.

GES's facility will produce both electric and thermal energy. The thermal energy that is used as an input back into the anaerobic digestion process effectively increases the efficiency of the electric production from the facility; is not used to directly produce electricity or useful, measureable thermal or mechanical energy at a retail electric customer's facility pursuant to G.S. 62-133.8(a)(1); and is not eligible for RECs. However, the thermal energy that is used to heat the chicken houses at the Collins Chick Farm is eligible to earn RECs pursuant to Commission Rule R8-67(g)(4).

GES shall annually file the information required by Commission Rule R8-66 on or before April 1 of each year. GES will be required to participate in the REC tracking system to be designated by the Commission in Docket No. E-100, Sub 121, and regularly provide information to the tracking system regarding metered electric generation data, qualifying thermal energy generation data, and the percent of those energy streams that is ultimately derived from poultry waste versus other biomass materials.

IT IS, THEREFORE, ORDERED as follows:

1. That the registration by GES of its electric generation facility, fueled by methane gas produced via poultry waste and other biomass materials, and located in Darlington County, South Carolina, as a new renewable energy facility shall be, and hereby is, accepted.

2. That GES 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 20th day of January, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

kh012010.02

DOCKET NO. P-120, SUB 26

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Petition of Sprint Communications Company, L.P. For Arbitration of an Interconnection Agreement With Pineville Telephone Company Pursuant to Sections 251(a), (b), and 252 of the Telecommunications Act of 1996	)) ORDER GRANTING SPRINT'S) REQUEST FOR A PARTIAL) TERMINATION OF PINEVILLE'S) SECTION 251(f)(1) RURAL) EXEMPTION

HEARD IN: Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on June 22, 2010

BEFORE: Commissioner Lorinzo L. Joyner, Presiding, and Commissioner William T. Culpepper, III, and Commissioner ToNola D. Brown-Bland

APPEARANCES:

FOR SPRINT COMMUNICATIONS COMPANY, L.P.:

Mary Lynne Grigg, McGuireWoods, LLP, 2600 Two Hannover Square, Raleigh, North Carolina 27601

William R. Atkinson, Sprint Communications L.P., 3065 Akers Mill Road, SE, Atlanta, Georgia 30339

FOR PINEVILLE TELEPHONE COMPANY:

Daniel C. Higgins, Burns, Day & Presnell, P.A., Post Office Box 10867, Raleigh, North Carolina 27605

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 July 15, 2009, Sprint Communications Company L.P. (Sprint) filed a Petition for Arbitration with the Town of Pineville d/b/a Pineville Telephone Company (Pineville) to establish an interconnection agreement (ICA) between them pursuant to the Telecommunications Act of 1996 (the Act). Sprint indicated that Pineville was an incumbent local exchange company (ILEC) with an authorized local service area. Sprint denied that it had requested anything implicating Pineville's rural telephone company exemption as set forth in Section 251(f)(1) of the Act. In support of its petition, Sprint invoked state law interconnection and number portability obligations, in addition to the provisions of the Act.

Sprint also noted that the Commission had granted Pineville a certificate as a competing local provider (CLP) on March 12, 2003, in Docket No. P-120, Sub 15, that directed Pineville to "open its existing LEC [local exchange carrier]-franchise area to local exchange and exchange access competition."

With regard to negotiations with Pineville, Sprint stated that on February 11, 2009, it sent a bona fide request for negotiation of an ICA under Section 251 and Section 252 of the Act to Pineville. Sprint also requested information concerning the port capability status of Pineville's switches. In response to the request for negotiation of an ICA, Pineville asserted that it was a "rural telephone company" within the meaning of the Act. As such, Pineville believed that Sprint must first comply with the provisions of Section 251(f)(1) of the Act to obtain interconnection, services, or network elements.

On August 7, 2009, Pineville filed a Preliminary Response to Sprint's Petition for Arbitration. In its response, Pineville alleged (or, in some instances, admitted allegations by Sprint) that (1) it is an ILEC as defined in Section 251(h) of the Act; (2) it is a rural telephone company as defined in Section 153(37) of the Act, serving 1,713 access lines as of June 30, 2009; (3) the Commission granted it a certificate as a CLP in Docket No. P-120, Sub 15 (*CLP Certificate Order*) in that portion of the Town of Pineville where it does not serve as an ILEC; (4) in the *CLP Certificate Order*, the Commission ordered Pineville to "open its existing LEC-franchise area to local exchange and exchange access competition"; and (5) its status as a rural telephone company was not affected by the *CLP Certificate Order*.

Pineville further asserted in its Preliminary Response that it had not engaged in negotiations with Sprint; consequently, it had not explicitly or implicitly waived its exemption as a rural telephone company. Because the parties had not negotiated, Pineville claimed that all issues between it and Sprint were unresolved. Pineville contended that it had no duty to negotiate with Sprint under Section 251(b) or Section 251(c) unless and until the Commission had completed an inquiry under Section 251(f)(1)(B). Pineville further stated that if the Commission, after such inquiry, should conclude that Pineville's exemption should be terminated, the Commission should implement a schedule for negotiation of an ICA.

In response to these issues, the Commission requested pre-hearing briefs and oral argument by order issued September 18, 2009, on certain procedural issues. The Commission directed the Public Staff to participate in the pre-hearing briefing and oral argument.

Briefs were filed by Sprint, Pineville, and the Public Staff on October 7, 2009, and an oral argument was held on October 12, 2009. The parties filed proposed orders on November 16, 2009.

On January 14, 2010, the Commission issued an *Order Holding Sprint's Petition to Establish an Interconnection Agreement in Abeyance* (*Abeyance Order*). In this Order, the Commission upheld Pineville's contention that under Section 251(c) and Section 251(f) of the Act, it is not required to negotiate with Sprint about the obligations set forth in Section 251(a) and Section 251(b) so long as its rural telephone company exemption remains in effect. Consequently, the fact that Sprint had limited its Requests of Pineville to those services addressed in subsection (a) and (b) did not render Pineville's rural telephone company exemption irrelevant. The Commission held that it was necessary to conduct an evidentiary hearing under Section 251(f)(1)(B) to determine whether Pineville's Section 251(f)(1) exemption should be removed; that Sprint and Pineville should propose an expedited discovery and hearing schedule; and that until the evidentiary hearing was conducted and decided, Sprint's petition for an ICA should be held in abeyance.

On January 25, 2010, Sprint and Pineville filed a joint proposed procedural schedule. On January 29, 2010, the Commission issued an order adopting the proposed schedule and setting the evidentiary hearing for June 15, 2010. The hearing was subsequently rescheduled for June 22, 2010.

On March 19, 2010, Sprint filed the direct testimony and exhibits of James R. Burt and Randy G. Farrar, and Pineville filed the direct testimony and exhibits of Joel O. Williams and Ann F. Wilson. On April 30, 2010, Sprint filed the rebuttal testimony and exhibits of witnesses Burt and Farrar, and Pineville filed the rebuttal testimony and exhibits of witnesses Williams and Wilson. All of the testimony was filed in both confidential and redacted form.

On June 4, 2010, Sprint and Pineville filed a Joint Issues Matrix.

The evidentiary hearing was held on June 22, 2010. The parties filed proposed orders and post-hearing briefs on September 8, 2010.

A glossary of the acronyms referenced in this *Order* is attached as Appendix A.

Based on the foregoing, the testimony and exhibits presented at the hearing, and the entire record in this matter, the Commission makes the following

FINDINGS OF FACT

1. Pineville is a rural telephone company within the meaning of Section 251(f)(1)(A) of the Act, and, as such, is exempt from the obligations imposed by Section 251(c) of the Act, subject to the Commission's authority to terminate its exemption; and accordingly, absent a termination of the exemption, Pineville is not obligated to negotiate an interconnection agreement with Sprint relating to the obligations addressed in Section 251(a) and Section 251(b) of the Act.

2. Pineville has not engaged in "conduct inconsistent with maintaining such exemption" so as to effect a waiver of that exemption by Pineville entering into Section 251(a) and (b) interconnection agreements with other telecommunications carriers without requiring any termination of Pineville's exemption.

3. Regardless of waiver, Pineville's exemption is subject to termination pursuant to Section 251(f)(1)(B) of the Act.

4. In accordance with Section 251(f)(1)(A)(i) of the Act, Sprint has made a bona fide request for interconnection with Pineville.

5. Sprint's request for Section 251(a) interconnection and Section 251(b) arrangements would not impose an undue economic burden on Pineville.

6. Sprint's request for Section 251(a) interconnection and Section 251(b) arrangements is technically feasible.

7. Sprint's request for Section 251(a) interconnection and Section 251(b) arrangements is consistent with Section 254 of the Act (other than Sections 254(b)(7) and (c)(1)(D)).

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

ISSUE NO. 1 – MATRIX ISSUE NO. 1: Does Pineville's claimed Section 251(f)(1) exemption apply to Sprint's request for Section 251(a) interconnection and negotiation of Section 251(b) arrangements?

POSITIONS OF PARTIES

SPRINT: No. Sprint asserted that, based on the uncontroverted testimony and evidence of record, Pineville is a rural telephone company within the meaning of Section 251(f)(1)(A) of the Act, and, as such, exempt from the obligations imposed by Section 251(c) of the Act subject to the Commission's authority to terminate its exemption.

PINEVILLE: Yes. Pineville asserted that its exemption under Section 251(f)(1) as a rural telephone company is applicable to Sprint's request for negotiation of Section 251(b) interconnection arrangements.

PUBLIC STAFF: Yes. The Public Staff stated that Pineville, as a rural telephone company, is exempt under Section 251(f)(1) from any obligations imposed on an ILEC under Section 251(c)(1), including any duty to negotiate with Sprint regarding its request for establishment of Section 251(b) arrangements.

DISCUSSION

All of the parties agree that this issue has been addressed by the Commission in its *Abeyance Order*. In the *Abeyance Order*, the Commission concluded that Pineville's Section 251(f)(1) exemption from Section 251(c) obligations was not rendered irrelevant by Sprint's request for arbitration under Section 251(a), along with certain Section 251(b) functionalities.

The Commission agrees with the Public Staff that there is no need to repeat the arguments raised by Sprint, Pineville, and the Public Staff during the pendency of the proceeding leading up to the *Abeyance Order*. The Commission adopts the discussion and conclusions in the *Abeyance Order* as support for its finding here that Pineville is a rural telephone company within the meaning of Section 251(f)(1)(A) of the Act, subject to the Commission's authority to terminate its exemption. Accordingly, absent a termination of the exemption, Pineville is not obligated to negotiate an interconnection agreement with Sprint relating to the obligations addressed in Section 251(a) and Section 251(b) of the Act.

CONCLUSIONS

The Commission concludes that Pineville is a rural telephone company within the meaning of Section 251(f)(1)(A) of the Act, and, as such, is exempt from the obligations imposed by Section 251(c) of the Act, subject to the Commission's authority to terminate its exemption. The Commission further concludes that, consistent with the *Abeyance Order* and absent a termination of the exemption, Pineville's claimed Section 251(f)(1) exemption applies to Sprint's request for Section 251(a) interconnection and negotiation of Section 251(b) arrangements.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

ISSUE NO. 2 – MATRIX ISSUE NO. 2: Has Pineville engaged in "conduct inconsistent with maintaining such exemption" so as to effect a waiver of that exemption by Pineville entering into Section 251(a) and (b) interconnection agreements with other telecommunications carriers without requiring any termination of Pineville's exemption?

POSITIONS OF PARTIES

SPRINT: Yes. By voluntarily entering into numerous interconnection agreements with commercial mobile radio service (CMRS) carriers, which provide for both direct and indirect interconnection arrangements, dialing parity pursuant to Section 251(b)(3), making its switches port capable pursuant to Section 251(b)(2), and establishing reciprocal compensation arrangements pursuant to Section 251(b)(5) – all without requiring termination of any purportedly applicable 251(f)(1) exemption, Pineville has engaged in conduct inconsistent with maintaining any purported 251(f)(1) exemption and the same should be considered waived.

PINEVILLE: No. Pineville promptly and consistently asserted its Section 251(f)(1) rural exemption from the time Sprint first contacted it. If the rural exemption can be waived and if the standard for such a waiver is as stated in this issue, neither of which is admitted, then Pineville has engaged in no conduct as to Sprint inconsistent with maintaining its rural exemption. Further, since Sprint is not interested in adopting Pineville's agreements with CMRS carriers, and thus is not willing to enter into agreements with the same rates, terms and conditions as contained in those agreements, Sprint's waiver argument is moot. Finally, Pineville argued that Pineville cannot be deemed to have waived or otherwise lost its rural exemption under federal law by having secured CLP authority under preexisting State law. Thus, Pineville has not engaged in "conduct inconsistent with maintaining" its rural exemption or otherwise voluntarily waived its rural exemption by entering into interconnection agreements with other telecommunications carriers.

PUBLIC STAFF: No. The Commission has held that a rural telephone company's Section 251(f)(1) exemption may be waived or terminated on a carrier-by-carrier or service-by-service basis, and thus Pineville's decision to enter into ICAs with certain CMRS carriers does not have the effect of waiving its Section 251(f)(1) exemption in its entirety.

DISCUSSION

Sprint witness Burt testified that in *Cricket Communications, Inc. v. Lexcom Telephone Company, Inc.*, Docket No. P-31, Sub 142 (June 29, 2005) (*Cricket Order*), the Commission held that a rural telephone company may waive its Section 251(f)(1) exemption by engaging in conduct inconsistent with maintaining the exemption; and that by entering into direct and indirect ICAs with several CMRS, or wireless, providers, Pineville has waived its exemption. According to witness Burt, the physical interconnection arrangements Pineville provides to wireless carriers are no different from the arrangements Sprint is requesting, and Pineville should not be allowed to interconnect with wireless carriers while refusing to interconnect with Sprint.

On cross-examination, witness Burt agreed that Pineville promptly asserted its rural exemption when it was first contacted by Sprint and refused to negotiate with Sprint. He further agreed that Sprint had the right to adopt any of the ICAs between Pineville and the wireless carriers, but it had not chosen to do so, because these agreements were not suitable for Sprint. Witness Burt acknowledged on cross-examination that in the *Randolph RAO*, Randolph had entered into interconnection agreements with several CMRS providers, but the Commission held that Randolph had not waived its rural exemption.

Pineville witness Williams testified that in order to avoid waiving its rural exemption, Pineville had refrained from entering into any negotiations with Sprint, and it had not interconnected with any CLPs, aside from its own CLP affiliate, PTC Communications. Pineville's ICAs with CMRS providers were obtained at its own request, not at the request of the wireless companies. Pineville would be willing to enter into an ICA with Sprint on the same terms and conditions as found in these ICAs with wireless companies, but Sprint was not interested in an ICA of this type, because it would not facilitate the type of competitive entry Sprint seeks.

On cross-examination, witness Williams testified that the reason why Pineville entered into ICAs with wireless companies was that it had been receiving traffic from these companies, and it was entitled to compensation for terminating calls from wireless providers to its customers, but it could not collect the payment to which it was entitled without having an ICA in place.

Finally, in the Public Staff's cross examination of Pineville witness Williams at the hearing, the Public Staff pointed out that the Town of Pineville filed a Proposed Order in the CLP certification proceeding in which the Town was eventually granted a CLP certificate with certain conditions and limitations. Specifically, in its Proposed Order in the CLP certification docket, Pineville included the following statement:

> The Town of Pineville's application for authority to provide service inside the municipal corporate limits of Pineville is hereby granted, with such grant of authority contingent on Pineville opening its existing franchise area to local exchange competition. Before Pineville commences any offering of service to the public as a CLP, Pineville shall mail written notice to all CLPs certificated by the Commission stating that Pineville's franchise area is open to local exchange and exchange access competition.[1]

Under cross-examination by Public Staff, Pineville's witness admitted that the above language did not draw any distinction between Pineville's CLP being open to competition under state law and Pineville's CLP being open to competition under federal law.[2] Despite this concession, Pineville argued in its Brief that any argument by Sprint or the Public Staff that Pineville's Section 251(f)(1) rural exemption was lost simply because the Town secured CLP authority under State law must fail because Pineville cannot be deemed to have waived or otherwise lost its rural exemption under federal law by having secured CLP authority under preexisting State law. According to Pineville, the Telecommunications Act and the Supremacy Clause of the United States constitution preempts this line of argument.

The Commission has held that the rural exemption may be waived or removed on a partial basis, with respect to specific services or suppliers but not others. The Commission specifically stated at page 11 of the *Cricket Order*: "It is clear that a RTC may voluntarily waive all *or parts* of its Section 251(f)(1) exemption." (Emphasis added.) Likewise, in the *Randolph RAO*, the Commission terminated Randolph's rural exemption with respect to the obligations of Sections 251(c)(1) and (2) of the Act, but not with respect to other obligations. Similarly, the rural exemption may be waived as to certain carriers and not to others. See Docket No. P-120, Sub 17, *Order Granting US LEC Petition Under Section 251(f)(1)* where Pineville waived its right to assert its rural exemption against a limited request for specific services made by US LEC while preserving its right to assert the exemption against future requests made by other carriers. In that docket, the Commission held that "the Commission's decision herein is without prejudice to Pineville's right in the context of any future request, to assert that any such request should not be granted."

Against this backdrop, Sprint has asked the Commission to find that Pineville has waived its right to assert and rely upon the Section 251 exemption as a shield against Sprint's interconnection request by voluntarily entering into numerous interconnection agreements with CMRS carriers, which provide for both direct and indirect interconnection arrangements, dialing parity pursuant to Section 251(b)(3), making its switches port capable pursuant to Section 251(b)(2), and establishing reciprocal compensation arrangements pursuant to Section 251(b)(5) and acquiescing in the Commission imposed requirement that Pineville open up its ILEC service territory to competition in order to receive Commission CLP certification.

The law with regard to the waiver doctrine is as follows. Waiver is a voluntary and intentional relinquishment or abandonment of a known right or privilege. *Medearis v. Trustees of*

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[1] Hearing Tr., at 387-88 (Williams) (quoting Public Staff Williams Cross-Examination Exhibit 1).

[2] Hearing Tr., at p. 388 (Williams).

Meyers Park Baptist Church, 148 N.C.App. 1, 10, 558 S.E.2d 199, 206 (2001); *ABC, Inc. v. Primetime 24, Joint Venture,* 17 F. Supp. 2d 478, 484-85 (M.D.N.C. 1998), *rev'd on other grounds, ABC, Inc. v. Primetime 24, Joint Venture,* 184 F.3d 348 (4th Cir. 1999). As a general proposition, a party "may waive a constitutional as well as a statutory benefit by express consent, by failure to assert it in apt time, or by conduct inconsistent with a purpose to insist upon it." *McNeal v. Black,* 61 N.C. 305, 307, 300 S.E.2d 575, 577(1983). *Bombardier Capital, Inc. v. Lake Hickory Watercraft, Inc.*178 N.C.App. 535, 632 S.E.2d 192 (2006).

A waiver may be express or implied. Express waivers are oral or written statements whereby a party intentionally and voluntarily relinquishes a known right or privilege. *ABC, Inc. v. Primetime 24, Joint Venture,* 17 F. Supp. 2d 478, 484-85 (M.D.N.C. 1998), *rev'd on other grounds, ABC, Inc. v. Primetime 24, Joint Venture,* 184 F.3d 348 (4th Cir. 1999). A waiver is implied when a person dispenses with a right 'by conduct which naturally and justly leads the other party to believe that he has so dispensed with the right. *Bombardier Capital, Inc. v. Lake Hickory Watercraft, Inc.,* 178 N.C.App. 535, 540, 632 S.E.2d 192, 196 (2006). The "intent" of a party to forego a right is a primary element of waiver. However, "[w]aiver by implication is not looked upon with favor by the courts; in fact, every reasonable intendment will be indulged against the waiver of fundamental rights, the courts never presuming acquiescence in their loss." Chemical Bank v. Belk, 41 N.C.App. 356, 366, 255 S.E.2d 421, 428 (1979). "When there is no express waiver, an implied waiver may be found in clear, decisive, and unequivocal conduct indicating an intent to waive the legal right involved." *ABC, Inc. v. Primetime 24, Joint Venture,* 17 F. Supp. 2d 478, 484-85 (M.D.N.C. 1998), *rev'd on other grounds, ABC, Inc. v. Primetime 24, Joint Venture,* 184 F.3d 348 (4th Cir. 1999).

No party to this proceeding contends that Pineville expressly waived its Section 251 exemption. Nor do the parties contend that Pineville waived its exemption by failing to assert it in apt time. Instead, the primary issue here is whether Pineville, by voluntarily entering into numerous interconnection agreements with CMRS carriers, has engaged in conduct inconsistent with maintaining the 251(f)(1) statutory exemption and thereby waived its Section 251 exemption. Sprint contends that Pineville has clearly engaged in conduct which should result in its statutory exemption being waived. Pineville and the Public Staff disagree. The Commission agrees with Pineville and the Public Staff.

After reviewing the evidence carefully and applying the aforementioned law to the facts of this case, the Commission simply cannot find that Sprint produced clear, decisive and unequivocal evidence that Pineville intended to relinquish its right to assert the Section 251 exemption by voluntarily entering into ICAs with wireless carriers. *Barclays Bank PLC v. Johnson,* 129 N.C.App. 370, 373, 499 S.E.2d 768, 770 (1998). In reaching this conclusion, we have examined each of the wireless agreements cited by Sprint as evidence that Pineville intended to waive its right to assert the exemption by entering into those agreements. In each of those agreements, we find that Pineville took specific steps to ensure that it preserved its ability to assert its Section 251 exemption against the party with whom it reached the agreement. Each of the wireless agreements contained the following language:

> WHEREAS, ILEC's entry into this agreement does not waive any rights it may have including the right to maintain that it is a rural company exempt from

Section 251(c) pursuant to Section 251(f)(1) of the Communications Act of 1934, as amended by the Telecommunications Act of 1996.

It therefore appears that Pineville and the individual carriers agreed that, by entering into these agreements, Pineville did not waive its ability to rely upon the Section 251 exemption either with respect to specific services or the specific carriers should the need arise. Faced with this language, it is difficult to believe that Pineville intended to preserve its ability to assert its Section 251 exemption against the specific carrier with whom it had negotiated an agreement while simultaneously and intentionally waiving its ability to assert the Section 251 exemption as to any subsequent carrier requesting interconnection.

In addition, the Commission also notes that the request to consummate an ICA did not originate with the wireless provider. Instead, Pineville initiated the discussion that resulted in the ICA with a wireless carrier. Pineville clearly had a legitimate reason for entering into ICAs with the wireless carriers. Had it not done so, according to the uncontradicted testimony of witness Williams, it would not have received compensation for terminating calls placed by these carriers' customers. The Commission is unwilling to hold that in order to avoid waiver of its Section 251(f)(1) exemption, a rural telephone company must forego revenue that it otherwise would be lawfully entitled to receive.

Finally, Sprint suggests that its waiver argument is buttressed by the Commission's Order in Pineville's CLP certification Docket, P-120, Sub 15 (*CLP Certification Order*). In that Order, the Commission, apparently, at the suggestion of and with the acquiescence of Pineville, conditioned its award of the CLP certificate to Pineville on Pineville opening its existing franchise area to local competition. The Commission has carefully reviewed this contention and notes that the Order does not specifically require Pineville to waive its federal statutory exemption in order to receive its CLP certificate. We also note that, subsequent to the entry of that *CLP Certification Order*, the Commission accepted Pineville's reservation of its right to assert the exemption in Docket No. P-120, Sub 17, i.e., the *Order Granting US LEC Petition Under Section 251(f)(1)*. Thus, in our view, Pineville's acceptance of condition that its local exchange be opened to competition in order to be awarded a CLP certification under state law does not indicate decisively and unequivocally that Pineville intended to waive its right to rely upon the federal statutory exemption.[1]

CONCLUSIONS

In conclusion, the Commission notes that, as a general proposition, waiver by implication is not looked upon with favor by the courts. Based on the foregoing, the Commission concludes that Pineville has not engaged in "conduct inconsistent with maintaining" its rural exemption or otherwise voluntarily waived its rural exemption by entering into interconnection agreements with other telecommunications carriers or acquiescing in the requirement that it open its local exchange to competition.

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[1] Because the Commission reaches the decision on this issue on these grounds, the Commission declines the opportunity to address the constitutional concerns raised by Pineville. See *Anderson v. Assimos*, 356 N.C. 415, 416, 572 S.E.2d 101, 102 (2002) ("[T]he Courts of this State will avoid constitutional questions, even if properly presented, where a case may be resolved on other grounds.")

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

ISSUE NO. 3 – MATRIX ISSUE NO. 3: If Pineville's claimed Section 251(f)(1) exemption has not otherwise been waived by Pineville's conduct, is Pineville's exemption subject to termination pursuant to Section 251(f)(1)(B)?

POSITIONS OF PARTIES

SPRINT: Yes. In accordance with the standard provided in Section 251(f)(1)(B), Sprint stated that it made a bona fide request for interconnection and has demonstrated by convincing evidence that its request is not unduly economically burdensome, is technically feasible, and is consistent with Section 254 of the Act (other than Sections 254(b)(7) and (c)(1)(D)). Regardless of waiver, based on the uncontroverted testimony and evidence of record, Pineville's exemption is subject to termination pursuant to Section 251(f)(1)(B) of the Act.

PINEVILLE: No. Since no substantive negotiations took place, Pineville stated that at this time it is unsure whether Sprint's request is technically feasible. Further, Pineville stated that Sprint cannot meet its burden of proof that its request would not impose undue economic burden on Pineville, and that Sprint's request is consistent with Section 254 of the Act (other than Sections 254(b)(7) and (c)(1)(D) thereof).

PUBLIC STAFF: Yes. Because each component of the criteria for determining if a rural exemption can be terminated has been met, the Public Staff stated that the Section 251(f)(1) rural telephone exemption for Pineville should be partially terminated, with respect to Sprint, to allow Section 251(a) direct and indirect interconnection, Section 251(b)(2) number portability, Section 251(b)(3) dialing parity including directory listings, Section 251(b)(5) reciprocal compensation, and directory distribution.

DISCUSSION

According to Section 251(f)(1) of the Act, a rural ILEC's exemption from compliance with Section 251(c) shall be terminated if (1) the rural telephone company has received a bona fide request for interconnection, services, or network elements; (2) the request is not unduly economically burdensome; (3) the request is technically feasible; and (4) terminating the rural ILEC's exemption is consistent with the universal service principles of Section 254. The Commission's Findings of Fact Nos. 4, 5, 6, and 7 address each of these issues in detail.

Summarizing, the Commission concludes that Sprint has made a bona fide request for Section 251(a) interconnection and Section 251(b) arrangements with Pineville. Further, the Commission does not believe the requested arrangements would impose an undue economic burden on Pineville. The Commission also concludes that Sprint's request for Section 251(a) interconnection and Section 251(b) arrangements is technically feasible. Finally, the Commission concludes that Sprint's request for Section 251(a) interconnection and Section 251(b) arrangements is consistent with Section 254 of the Act (other than Sections 254(b)(7) and (c)(1)(D)).

CONCLUSIONS

As a result of these findings, the Commission concludes that, in this case, each component of the criteria for determining if a rural exemption can be terminated has been met. Therefore, the Commission concludes that the Section 251(f)(1) rural telephone exemption for Pineville should be partially terminated, with respect to Sprint, to allow Section 251(a) direct and indirect interconnection, Section 251(b)(2) number portability, Section 251(b)(3) dialing parity including directory listings, Section 251(b)(5) reciprocal compensation, and directory distribution. With a partial termination of Pineville's rural exemption, Sprint can now enter into negotiations with Pineville for an interconnection agreement pursuant to the terms outlined in its February 11, 2009, letter to Pineville.

The Commission further concludes that Pineville should be directed to enter into negotiations with Sprint and that the statutory timelines as identified in Section 252(b)(1) of the Act should begin on the effective date of this Order.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

ISSUE NO. 4 – MATRIX ISSUE NO. 3(a): Did Sprint make a bona fide request for interconnection to Pineville?

POSITIONS OF PARTIES

SPRINT: Yes. Sprint noted that Sprint witness Farrar testified that by letter dated February 11, 2009, from Ms. Ellen Fuller, Sprint Contracts Negotiator, to Mr. Gary Creech, Pineville Plant Manage, Sprint stated, "This letter serves as a request to negotiate an interconnection agreement for the State of North Carolina pursuant to Sections 251 and 252 of the Communications Act of 1934 as amended (the 'Act') between Sprint Communications Company L.P. ('Sprint'), a telecommunications carrier, and Pineville Telephone Company ('Pineville'), an incumbent local exchange carrier." Sprint stated that it included this bona fide request as Exhibit 1 to Sprint's Petition instigating this proceeding.

PINEVILLE: Pineville asserted that it does not deny receipt of Sprint's February 11, 2009 letter. Further, Pineville stated that it will not contend that Sprint did not make a bona fide request for establishment of Section 251(a) interconnection and Section 251(b) arrangements to Pineville by the February 11, 2009 letter.

PUBLIC STAFF: Yes. The Public Staff stated that Sprint's February 11, 2009 letter to Pineville was a bona fide request for interconnection in accordance with Section 251(f)(1)(A)(i) of the Act.

DISCUSSION

As noted by the parties in their Proposed Orders, this issue is not in contention between the parties. Sprint asserted in its petition and testimony that its February 11, 2009 letter to Pineville was a bona fide request for interconnection, and Pineville has not disputed Sprint's contention. Therefore, the Commission finds, based on the record, that Sprint did make a bona fide request for interconnection to Pineville.

CONCLUSIONS

The Commission concludes that Sprint's February 11, 2009 letter to Pineville constitutes as a bona fide request for interconnection.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

ISSUE NO. 5 – MATRIX ISSUE NO. 3(b): Would Sprint's request for Section 251(a) interconnection and Section 251(b) arrangements impose an undue economic burden on Pineville?

POSITIONS OF PARTIES

SPRINT: No. Sprint asserted that, based on the Eighth Circuit Court's standard of looking at the economic burden on the entire company, as demonstrated by the economic burden analysis performed by Sprint in connection with this proceeding, Sprint's request is not unduly economically burdensome to Pineville. Sprint also maintained that Sprint's request for Section 251(a) and Section 251(b) interconnection is not substantively different than the Section 251(a) and Section 251(b) interconnection provided by Pineville to other carriers which, by the very nature of such services, are not unduly economically burdensome.

PINEVILLE: Yes. Pineville argued that the interconnection requested by Sprint would impose an undue economic burden on Pineville. Pineville asserted that the revenue losses that would result from the proposed competitive entry by Sprint/Time Warner Cable would effectively eliminate Pineville's ability to generate capital necessary to provision and improve its network and to continue to provide state of the art telecommunications services that residents and businesses in the Pineville exchange have come to expect and demand. Pineville contended that operating at a loss is not a sustainable business model.

PUBLIC STAFF: No. Sprint performed a financial analysis of Pineville's current financial condition and determined that the company was currently profitable and with financial ratios that were reasonable for a municipally-owned company. Sprint performed further analysis of the company based on projections of the number of residential and business subscribers that might switch to the Sprint/Time Warner Cable business model and found that Pineville would continue to experience positive operating income.

DISCUSSION

The core question in this docket revolves around whether the Commission should terminate portions of the Subsection 251(c) exemption[1] that Pineville enjoys as a "rural

[1] The partial termination of the Subsection 251(f)(1) exemption sought by Sprint—i.e., Section 251(c)(1) concerning Pineville's duty to negotiate--would enable negotiations and, if necessary, arbitration concerning direct and indirect interconnection (Section 251(a); number portability (Section 251(b)(2)); dialing parity, including

telephone company" pursuant to Section 251(f)(1) of the Telecommunications Act.[1] Subsection (f)(1)(A) reads:

> (A) EXEMPTION. — Subsection (c) of this section shall not apply to a rural telephone company until (i) such company has received a bona fide request for interconnection, services, or network elements, and (ii) the State commission determines . . . that such request is *not unduly economically burdensome, is technically feasible, and is consistent with Section 254 (other than subsections (b)(7) and (c)(1)(D) thereof)*. (Emphasis added)

Although all the criteria are important and must be satisfied before the Section (f)(1) can be removed, the criterion that is apt to be the most controversial is the one that is cast in the negative - that the request needs to be proved to be *not* unduly economically burdensome to the rural telephone company for the exemption to be removed.

The Commission has already extensively addressed its understanding of the meaning of the Subsection (f)(1)(A) criteria, including the "unduly economically burdensome" language, in the *Randolph* docket, more specifically, in the *RAO* in Docket No. P-294, Sub 30, issued on August 29, 2008. The Commission noted that Congress had "provided little guidance as to the manner in which this standard should be applied" and that the Federal Communications Commission's (FCC's) attempt at clarification - that the application of Section 251(c) to an affected rural LEC "would be likely to cause undue economic burden beyond the economic burden typically associated with efficient competitive entry" to justify retention of the exemption - had been rejected by the Eighth Circuit Court of Appeals in *Iowa Utilities Board v. FCC*, 219 F.3d 744 (Eighth Circuit 2000), rev. on other grounds, 535 U.S. 467 (2002) (*Iowa Utilities Board*). The Eighth Circuit wrote:

> If Congress had wanted the state commission to consider only the economic burden which is in excess of the burden ordinarily imposed on a small or rural ILEC by a competitor's requested efficient entry, it could easily have said so. Instead, its chosen language looks to *the whole of the economic burden that the request imposes, not just a discrete part*. (Emphasis added).

It was, thus, the Commission's understanding in *Randolph* that it needed to look at the whole of the economic burden that Sprint's request for interconnection imposed on the rural ILEC. Moreover, the Commission also realized that it must bear in mind in the Eighth Circuit's analysis that, even though small and rural ILECs may be entrenched in their markets but may have less financial capacity than larger and more urban ILECs to meet interconnection requests, the small and rural ILECs must nevertheless yield to the forces of competition if the requesting

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directory listings (Section 251(b)(3)); and reciprocal compensation and directory distribution (Section 251(b)(5)).

[1] No one disputes that Pineville, an ILEC owned by a municipality, meets the formal requirements of being a rural telephone company as defined in Section 3(a)(47) and can avail itself of the relevant exemptions. While there is no time limit set in Subsection (f)(1)(A) as to how long a rural ILEC can take advantage of this exemption, it is rendered in effect a temporary exemption for a rural ILEC at such time as a Commission decides to lift it. Pineville has already enjoyed its exemption from Subsection (c) since the passage of the Telecommunications Act in 1996 - i.e., for nearly 14 years.

carrier can demonstrate, in addition to the other Section 251(f)(1) requirements, that the economic burden imposed by the request is not undue; in other words, the burden does not exceed what is appropriate and is not excessive. But in order to have an operational standard, the Commission must decide on a test to determine what burden is appropriate and is not excessive.

Accordingly, after considering that record evidence and the arguments advanced by the parties in *Randolph*, together with the relevant case law, the Commission formulated a standard of what would constitute an undue economic burden. The Commission set it forth in one sentence but two separate clauses. The first clause addressed the undue economic burden test and the second addressed the Section 254 universal service test. The Commission wrote that "Sprint's request will not damage Randolph economically *to such an extent that its continued operation is endangered or that it will be forced to increase rates or reduce service in a way that is inconsistent with the state and national policy favoring the availability of basic telephone service to all citizens at affordable rates.*" (*Randolph RAO*, p. 16) (emphasis added).

The Commission continues to believe that the above are the appropriate tests for these prongs of the Subsection (f)(1) exemption standard.[1] The Commission also notes with respect to the undue economic burden standard that the language of the statute ("such request is not unduly economically burdensome") and the test that the Commission has formulated pursuant to it ("will not damage [the rural ILEC] economically to the extent that its continued operation is endangered") are entirely consistent with each other. Moreover, both the endangerment test under the undue economic burden standard and the affordable availability test under the universal service standard by their nature contemplate and require assessment of likely *future*

[1] In its Post-Hearing Brief Pineville for the first time decried the Commission's definition of undue economic burden as "unduly severe and restrictive" with respect to Pineville. In its place, it proposed the standard adopted by the North Dakota Public Service Commission in *Mid-Continent Communications/Missouri Valley Communications, Inc. Rural Exemption Investigation, Case Nos. PU-08-61 and PU-081-176,* where that Commission stated: "Even though the loss of revenue might not threaten Missouri Valley's ability to offer existing services in the immediate future, its efficiency in offering those services would be damaged because the revenue loss would unduly impair Missouri Valley's ability to invest in facility upgrades and replacements." Pineville reported that the United States District Court for the District of North Dakota affirmed the North Dakota Public Service Commission's decision. *MidContinent Communications v. North Dakota Public Service Commission et al.*, Case 1:09-cv-00017-DLH-CSM (D.N.D April 15, 2010.) See, also, *CRC Communications of Maine, Inc., Investigations Pursuant to 47 U.S.C. Sec. 251(f)(1) Regarding CRC of Maine's Request, Dockets 1009-40, 2009-41, 2009-42,2009-43, and 2009-44 (July 9, 2010)* (The Maine Public Utilities Commission wrote: "[W]e adopt a legal standard of 'undue economic burden' similar that that approved by the North Dakota Public Service Commission and affirmed by the District Court for the District of North Dakota. Thus we hold that an undue economic burden exists when competitive entry is likely to undermine an ILEC's revenue to such an extent that the ILEC is hampered in its ability to offer quality telecommunications services, attract sufficient capital and undertake prudent investments in infrastructure while maintaining its ability to fulfill its role as a carrier of last resort." *CRC Order*, pp. 21-22)

economic conditions pertinent to the rural telephone company and its customers. In other words, the analysis under Subsection (f)(1)(A) cannot be a static one; it must be dynamic.[1]

The Commission, of course, recognizes that Pineville, in its Post-Hearing Brief, has advocated the somewhat more indistinct and, in rural ILEC terms, the more favorable "impairment" test adopted by the North Dakota Public Service Commission (PSC) and Maine Public Utilities Commission (PUC) - that is, an undue economic burden exists if there is an undermining of an ILEC's revenues "to such an extent that an ILEC is likely to be *hampered* in its ability to offer quality telecommunications services, attract sufficient capital, and undertake prudent investments in infrastructure while maintaining its ability to fulfill its role as carrier of last resort" (as in Maine) or there is undue *impairment of* the rural ILEC's "ability to invest in facility upgrades and replacement" (as in North Dakota). While the Commission will discuss evidence bearing on the undue economic burden standard in more detail below, we would simply now observe that the terms "hamper" and "impair" in this context are synonymous and tend to establish a relatively low threshold for a finding of an undue economic burden while the "endangerment" standard (as in endanger continued operation) previously adopted by the Commission establishes a relatively higher threshold.[2] It is therefore not surprising that Pineville would prefer the "impairment" standard to an "endangerment" standard when assessing what is and is not an undue economic burden.

In any event, in a system where individual public service commissions are entrusted with the responsibility of assessing whether a Subsection (f)(1)(A) exemption, or parts of it, should be retained or taken away with respect to a specific rural ILEC, it is to be expected that there may evolve different tests for the undue economic burden standard in different states which are nevertheless consistent with the statutory language and with the overall purposes of the statute. The Commission believes that the "endangerment" test we have adopted in this State is a reasonable interpretation of the statutory language and that our analysis of it, as will be seen below, comports with the *Iowa Utilities Board's* admonition that we should look to "the whole of the economic burden that the request imposes, not just a discrete part of it."

In either the case of "impairment" or of "endangerment," the Commission notes that the analysis of undue economic burden under either of these tests must include consideration of the probable effect of allowing competition on the future prospects of a given rural ILEC. It therefore follows that relevant consideration should also be given to those actions that a rural

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[1] The Commission recognized this in the *Randolph* case. "Third, Randolph's analysis assumes that Randolph will not make any response to competitive entry by Sprint and Time Warner. The Commission does not believe that this is a reasonable assumption. Businesses respond in a large variety of ways to competition, such as introducing new service offerings, improved customer service, and expense reductions, just to name a few typical examples. Randolph projects the net income impact of competitive entry without taking into account any possibility that the company would take action in response to a newly-arrived competitive threat. Even though the Commission expects Randolph to affirmatively react to the advent of competition from Sprint/Time Warner, Randolph's analysis does not take this possibility into account in any way." (*Randolph RAO*, p. 19)

[2] "Hamper" is defined in *Webster's New World Dictionary of the American Language*, Second College Edition, 1972 as "to keep from moving or acting freely; hinder; impede, encumber." Similarly, "impair" is defined as "to make worse, less, weaker, etc., damage, reduce." *Id.* "Endanger," on the other hand, means "to expose to danger, harm or loss; imperil." *Id.* The last part of the definition is the sense in which the Commission has used it in its articulation of the undue economic burden standard.

ILEC can proactively take in the present or in the future to ameliorate the probable effects of competition, if interconnection is approved. For example, to name just a few, a rural ILEC which is currently rate base/ rate of return regulated may alter its structure by availing itself of a price regulation plan allowing for more flexibility in rate setting. A rural ILEC whose rates were established in a framework without local competition may need to raise its basic local service rates to something closer to a true marginal rate while still being able to offer affordable basic telephone service. A rural ILEC may need to offer more and different bundles of services, e.g., television or broadband service as a response to, or in anticipation of, competition. These, among others, are structural changes that a reasonable rural ILEC inherently has the ability to make to avoid either "impairment" or "endangerment," and ought to be considered as relevant factors along with the other evidence presented in this case in assessing how undue the economic burden is. Another "structural" consideration that is not under the rural ILEC's control but simply exists is the extent to which the competitor has asked the exemption to be removed—in other words, is the removal partial and, if so, to what degree, or is it complete; and how does that affect the economic burden?

The Commission will now examine the evidence presented by both parties regarding the issue of undue economic burden and reach conclusions based on the "endangerment" test and other relevant "structural" considerations.

Sprint

Sprint witness Farrar testified that Sprint's competitive entry into Pineville's territory does not represent an "undue economic burden" on Pineville. Witness Farrar explained that Sprint performed two separate analyses of whether its interconnection request imposes an undue economic burden on Pineville – an analysis of Pineville's current financial condition, and an analysis of the projected economic burden Sprint's competitive entry will have on Pineville. Witness Farrar noted that he performed similar analyses in the Sprint/Randolph proceeding.

Witness Farrar also testified to the purpose of the "undue economic burden" standard of the Act, stating that this standard is concerned with direct costs to the ILEC of meeting the obligations of Section 251(c) of the Act, such as the cost to very small rural ILECs to meet these obligations. Sprint maintained that its competitive entry does not cause Pineville to bear any direct costs, as it is not seeking unbundled network elements or collocation space, but is seeking to exchange traffic with Pineville as do other landline and wireless carriers that interconnect with Pineville.

Witness Farrar stated that in order to examine Pineville's financial condition, Sprint calculated several financial ratios for the four-year period of 2006 through 2009 commonly used to assess a telecommunications company's financial well-being: revenue per access line; operating income to net plant; return on average equity; equity ratio; and dividend payout ratio. Witness Farrar compared the results of his calculations to the comparable publicly available data of other ILECs, which was taken from the FCC's Automated Reporting Management Information System (ARMIS) database, which witness Farrar identified as the only publicly available aggregation of financial information on the telecommunications industry. Sprint admitted that ARMIS data does not contain rural telephone company financial data, but Sprint pointed out that there simply is no publicly available collection of financial data for rural telephone companies per se.

Witness Farrar also noted that Pineville is not an investor-owned, for-profit company, but is a municipal-owned company, with no fiduciary responsibility to shareholders and pays no corporate income taxes. Thus, witness Farrar stated, Pineville does not necessarily have the same financial incentive of a for-profit enterprise; all profits (or losses) are retained by the municipal entity.

Sprint concluded, based on its first analysis, that Pineville is a financially sound and profitable enterprise, with the resources to provide a $1,400,000 subsidiary during the last three calendar years to its CLP affiliate, PTC Communications. Sprint also noted that, at the hearing, Pineville witness Wilson admitted that taking the considerably higher estimates of revenue losses resulting from Sprint's competitive entry from her testimony at face value, those higher revenue loss estimates still only amount to 37% of Pineville's voluntary $1,400,000 subsidy to its CLP affiliate over the same three-year period. Sprint asserted that, furthermore, Pineville acknowledged in its responses to Sprint's discovery that in its 2010 budget, it anticipates an additional transfer of $670,000. Sprint noted that Pineville did not perform any independent analysis of its own financial condition in this proceeding, and did not explain why it did not undertake such an analysis.

Witness Farrar explained that to conduct its second analysis, the projected economic burden, Sprint made three major assumptions: (1) Sprint will enter the market six months after Pineville's rural exemption is lifted and an interconnection agreement is completed and signed; (2) Sprint will achieve certain market penetration rates; and (3) Pineville will realize minimal operating expense reductions. Witness Farrar described the results of Sprint's analysis in terms of Pineville's percentage decrease in earnings 1.5 years, 2.5 years, and 3.5 years after the rural exemption is lifted and an interconnection agreement is completed and executed. Sprint's economic burden analysis comprised five steps: (1) identify Sprint's anticipated market penetration rates as a percentage of households passed; (2) calculate the number of Pineville access lines subject to competition; (3) calculate the year-end number of Pineville access lines that will be lost; (4) calculate the mid-year percentage of Pineville's access lines and revenues that will be lost; and (5) calculate the reduction in Pineville earnings resulting from the loss in revenues. Witness Farrar's market penetration analysis utilized Sprint's actual average penetration rates across 161 rural markets nationwide to project the degree of Sprint's percentage of competitive entry into Pineville's service area in the third year after Sprint's competitive entry, and project an estimated revenue loss to Pineville. Sprint asserted that its estimate of access line losses and associated revenue losses attributable to Sprint's competitive entry is conservative to Pineville's advantage because, among other reasons, Sprint used its own higher actual penetration rates in the analysis, and Sprint assumed a 0% reduction in Pineville operating expenses, even though Pineville will undoubtedly realize some incremental decline in its expenses as it loses customers. Sprint maintained that, in light of Sprint's modest projected access line and associated revenue losses that Pineville would experience due to Sprint's market entry, witness Farrar judged that they could not cause the dire financial consequences predicted in Pineville's prefiled testimony.

Sprint stated that, regarding Pineville's contentions that Sprint's projected access line loss analysis did not adequately take into account projected business lines that Pineville would lose due to Sprint's competitive entry, witness Farrar testified, based on Sprint's actual experience in 161 rural markets across the nation, to the percentage of the number of Sprint's residential customers that the number of Sprint's business customers on the Sprint/TWC cable model would represent. Sprint asserted that, moreover, at the hearing, Pineville witness Williams acknowledged that the emphasis on residential customers in Sprint's/TWC's service offering is consistent with the normal cable model that is mainly residential because the video service originally went to residence and not business.

Sprint noted that its witnesses touched on several factors in their testimony that may tend to negatively impact Sprint's actual market penetration rates for Pineville's local service territory. Sprint witness Burt noted that due to the percentage of homes in its service territory currently served by Pineville[1], there may be considerably less "pent-up demand" than Sprint generally would expect to see when entering a rural ILEC's local market. Sprint stated that, in addition, since a number of eligible Pineville local customers have apparently already availed themselves of an intermodal competitive alternative to Pineville's service, there is probably considerably less of a backlog of Pineville customers ready to switch to a wireline competitive alternative, as soon as one is available, than Sprint would customarily anticipate. Sprint asserted that, as a result, the Sprint/TWC model may well win fewer customers in the short-run than usual in Pineville's service territory.

Sprint maintained that another factor that might negatively impact Sprint's actual market penetration rates in Pineville's territory is the fact that Pineville has recently filed a Video Franchise application with the North Carolina Secretary of State's office. Sprint noted that, under North Carolina law, Pineville has 120 days from the date of its filing to commence service. Sprint asserted that, as Pineville witness Wilson admitted at the hearing, Pineville's provision of video programming services to its local telephone customers will likely allow Pineville to much more successfully compete against the Sprint/TWC competitive entry. Sprint noted that this factor, however, was not considered at all in Sprint's economic burden analysis. Sprint argued that at the time at which Pineville begins to provide video services in its local service territory, the express limitation on Pineville's exemption contained in Section 251(f)(1)(c) would appear to apply. Further, Sprint stated, both as a matter of policy and a matter of fundamental fairness, if a rural ILEC is effectively competing with a cable company for video programming customers, then a cable company should be allowed to compete with the rural ILEC for voice customers.

Sprint asserted that Pineville based its undue economic burden analysis in part on TWC market penetration data from years three through five of TWC's service rollout instead of years one through three as reflected in Sprint's analysis, thus skewing Pineville's projected penetration rates. Sprint argued that, in another scenario, Pineville selected some of Sprint's very highest actually obtained penetration rates from the 161 rural markets in which Sprint operates to argue that Sprint's penetration rates in Pineville's territory could be similar. Sprint noted that, yet, Pineville's witness admitted that if the tables were turned and Sprint's witness had selected some of the very lowest of Sprint's actual penetration rates across 161 rural markets for use in its analysis, Pineville would not have been in favor of that methodology. Sprint noted that, finally,

[1] The actual percentage is confidential.

Pineville's use of a residential market penetration rate to project business lines lost due to Sprint's competitive entry leads to inaccurate results, which are divorced from the reality of both Sprint's and TWC's actual business penetration rates.

Sprint argued that Pineville's choice to focus on comparing projected lost revenues to its 2009 level of earnings, which are lower than the 2006 through 2009 period as a whole that witness Farrar employed, further skews the analysis. Sprint maintained that, more importantly, while focusing on Pineville's 2009 financial results, Pineville failed to note that during 2009, Pineville still transferred $500,000 of the total $1.4 million in transfers from Pineville to its CLP affiliate during 2007 through 2009. Sprint stated that while Pineville's actions to fortify its CLP affiliate to address current and anticipated competition are not objectionable in and of themselves, Pineville's use of its very most recent financial experience, exclusive of Pineville's voluntary transfers to its CLP affiliate, as evidence that Sprint's competitive entry should be disallowed, demonstrates circular reasoning that the Commission should reject.

Sprint further maintained that, with regard to Sprint's/TWC's current market penetration rates in that portion of the Town of Pineville that falls outside of Pineville's certificated local service territory, i.e., in BellSouth Telecommunications, d/b/a AT&T's Charlotte exchange, regardless of whether Sprint's penetration percentage in one specific, non-rural ILEC exchange is relevant to the Commission's determinations in this exemption termination proceeding, the fact remains that Pineville's CLP affiliate is also certificated to serve and is presently serving customers in the portion of the Town of Pineville located in AT&T's Charlotte exchange. Sprint argued that, accordingly, to the extent that Pineville's subsidization of its CLP affiliate bears fruit and Pineville's CLP prospers in the Charlotte exchange and gains market share, Sprint's/TWC's market penetration percentage in the Charlotte exchange may well level off, if not decrease, over time.

Sprint argued that the evidentiary record in this proceeding demonstrates clearly, and Pineville witness Wilson admits, that Pineville is a financially viable and sound company that has traditionally generated a profit, has the very lowest or among the very lowest single-line residential and business local rates in North Carolina ($4.77 per month for single-line residential and $10.62 per month for single-line business which Sprint maintains are both far under the national average rates), and among the lowest rates in the nation, had the financial wherewithal to provide a $1,400,000 subsidy over the last three years to its CLP affiliate, and that plans to make an additional $670,000 transfer in 2010, and receives federal universal service fund money from various funds.

Sprint concluded from its analysis that Sprint's competitive entry into Pineville's service territory does not represent an undue economic burden for Pineville. Sprint asserted that Sprint's request will not damage Pineville economically to such an extent that its continued operation is endangered or that it will be forced to increase rates or reduce service in a way that is inconsistent with the state and national policy favoring the availability of basic telephone service to all citizens at affordable rates.

Pineville.

Pineville provided its own evidence on whether Sprint's/TWC's request for interconnection would result in an undue economic burden on Pineville. Pineville noted that witness Farrar describes Pineville as a municipal-owned company without a profit motive. Pineville asserted that whether Pineville is investor-owned or a municipal enterprise, and thus whether or not it has the same financial incentive as a for-profit enterprise as witness Farrar contends, is of no relevance to the economic burden analysis. Pineville argued that Sprint's suggestion that it is less important for Pineville to earn a profit than it is for an investor-owned enterprise, and therefore that some great tolerance for economic burden should be imposed on it as a municipal enterprise, has no basis in the Act. Pineville asserted that there is no aspect of Section 251(f)(1) which would support the application of a different economic burden analysis to Pineville than to an investor-owned rural telephone company. Pineville maintained that the applicable standard is simply whether Sprint can establish that its requested interconnection would not impose an undue economic burden on Pineville, and the fact that Pineville is an municipal enterprise has no bearing on that issue.

Pineville opined that, if its rural exemption is terminated, it would bear the economic burden of revenue losses resulting from Sprint/Time Warner being allowed to offer service in the Pineville exchange, while leaving Pineville to provide service to the less profitable customers in its service area; those customers unwilling or financially unable to subscribe to a mandatory bundled package of services. Pineville maintained that, as customers and revenues are lost, Pineville's ability to bear the costs of continuing to offer advanced services to 100% of its customers, especially DSL service, will be put at increased risk. Pineville stated that this is not an illusory problem or concern, as the risk to rural ILECs of cream skimming[1] has been recognized by the FCC.

Pineville argued that the Commission's definition of undue economic burden determined in the Sprint-Randolph docket was excessively severe and too restrictive and that the Commission should take a more balanced and longer term view in this docket. Pineville noted that the North Dakota PSC and the Maine PUC have adopted a more balanced and longer term view of undue economic burden in recent proceedings involving requests for termination of the Section 251(f)(1) exemptions of rural telephone companies.

Pineville recommended that the Commission conclude in this proceeding that an economic burden standard which is predicated on an ILEC's ability to simply survive competitive entry would be inadequate to protect the public interest in the continued viability of rural telephone companies and that the Commission should adopt the standard recently articulated by the Maine PUC.

Pineville asserted that many of the same factors noted in the North Dakota PSC and Maine PUC decisions apply to Pineville. Pineville argued that, for the year ending

[1] Pineville defined cream skimming as the practice of targeting only the customers that are the least expensive to serve, thereby undercutting the ILEC's ability to provide service throughout the area.

June 30, 2009, Pineville had total operating income of $61,638[1]. Pineville stated that its income from its retained earnings was $141,661, giving it a total income for that year of $203,299. Pineville maintained that even if the revenue losses resulting from Sprint's requested interconnection did not cause Pineville to operate at a loss in the first year after interconnection with Sprint, or did not immediately threaten Pineville's economic survival, Pineville's earnings are already so low that its efficiency in offering service would be severely damaged because its readily expendable revenue losses would unduly impair Pineville's ability to invest in facility upgrades and replacements, or maintain its rates or service levels.

Pineville further argued that even line/revenue losses in the range projected by Sprint would be sufficient to seriously and unduly damage Pineville's efficiency in offering service and impair Pineville's ability to invest in facility upgrades and replacements. Pineville asserted that more realistic line loss projections establish that Pineville would endure revenue losses sufficient to seriously impede Pineville's ability to maintain its operations. Pineville noted that, for example, TWC reported to the U.S. Securities and Exchange Commission (SEC) that in the year ending December 31, 2008, TWC provided Digital Phone service to 14.4% of the homes that it passed, and its penetration rates as to homes passed is increasing at a rate of 1% per year.

Pineville stated that, given that Pineville's net operating income was $61,638 in 2009[1], access line losses in the ranges indicated by TWC's publicly reported data, TWC's success in other rural markets, and its success in the Charlotte exchange, Sprint/TWC's entry into Pineville's territory would be devastating. Pineville asserted that such a result would harm Pineville's ability to support its maintenance and provisioning of the network for enhanced services and new service offerings that customers' desire, and would certainly impede Pineville's ability to compete on a level playing field with an entity such as Sprint/TWC.

Pineville also argued that the ARMIS report data utilized by Sprint concerning mid-size and large ILECs is of little relevance to any meaningful analysis of Pineville's financial condition or earnings. Pineville asserted that the performance ratios and financial circumstances of large LECs filing ARMIS reports are not comparable to a small ILEC like Pineville. Pineville stated that Sprint's analysis based on the ARMIS data provides no probative evidence as to Pineville's financial condition or ability to endure the economic consequences of Sprint's competitive entry. Pineville maintained that this analysis likewise provides no proof that Sprint's request would not impose an undue economic burden on Pineville.

Pineville opined that Sprint did not meet its burden of proving that its proposed interconnection would not impose an undue economic burden on Pineville. Pineville asserted that Sprint's line-loss estimates are subject to serious question, as shown by the data Sprint produced in response to Pineville's data requests, the matters addressed in the testimony of Pineville witness Wilson, and the testimony of Sprint witness Farrar as to the residential penetration rate secured by Sprint/TWC in that portion of the Town of Pineville located in the Charlotte exchange. Pineville maintained that even if the standard on the economic burden issue was whether Sprint's request for interconnection would damage Pineville economically to such

[1] The Commission notes that, according to Exhibit RGF-3, Pineville's total operating income was $70,957 for the year ended June 30, 2006; $234,652 for the year ended June 30, 2007; $270,811 for the year ended June 30, 2008; and $61,638 for the year ended June 30, 2009.

an extent that its continued operation is endangered, or that it will be forced to increase rates or reduce services, Sprint could not, on the record before us, satisfy its burden of proof as to that issue.

Pineville concluded that Sprint has failed to prove as required by Section 251(f)(1)(B) that its requested interconnection with Pineville would not impose an undue economic burden on Pineville. Pineville opined that, based on the record of evidence in this proceeding, the economic burden that Sprint's requested interconnection would impose on Pineville would likely undermine Pineville's revenue to such an extent that Pineville is likely to be hampered in its ability to offer quality telecommunication service and undertake prudent investments in infrastructure while maintaining its ability to fulfill its role as a carrier of last resort. Pineville asserted that this would constitute an undue economic burden and would also impair Pineville's performance of its universal service obligations.

Public Staff

The Public Staff maintained in its Proposed Order that the critical question underlying this issue is whether interconnection with Sprint, and the resulting competition with Sprint and Time Warner, will damage Pineville to such an extent that its continued operation is endangered, or to a point where it is forced to increase rates or reduce service in a way that is inconsistent with the state and national policy that basic telephone service should be available to all citizens at affordable rates.

The Public Staff stated that there can be no question that the introduction of telephone competition will result in some risk of economic harm to any ILEC, and the risk may be higher for Pineville than for many of the other ILECs because of its small size. The Public Staff asserted, however, that the Commission must balance this risk against the state and national policy favoring competition and customer choice in telecommunications services.

The Public Staff stated that Sprint witness Farrar, through his economic analyses, offered evidence suggesting that Pineville has been able to establish a reasonably profitable financial position, and that Pineville should be able to maintain its profitability even with the loss of customers in the initial years following the introduction of competition from Sprint and Time Warner. The Public Staff noted that Pineville witness Wilson challenged a number of assumptions and conclusions presented by witness Farrar, and offered evidence that projected Pineville would suffer significant financial stress if the rural exemption was terminated. The Public Staff opined that, nevertheless, Pineville has sufficient resources to withstand any revenue loss likely to occur in the near future as a result of interconnection with Sprint.

The Public Staff maintained that one factor which contributes to its opinion is found in the financial reporting that Pineville makes with the Commission. The Public Staff noted that based on Pineville's TS-1 Report Schedules 3 and 4, Pineville's Operating Income for the time period June 2006 through June 2009 was much larger than the amounts used by witness Farrar in his attachment RGF-3. The Public Staff stated that by substituting the TS-1 amounts in the analysis performed by witness Wilson, the projected operating income resulting from the loss of access lines will stay positive through the years covered by the forecast, indicating that the impact on Pineville will not be as dire as projected. The Public Staff further asserted that, though it might not be an option Pineville would prefer to pursue, an increase in what is generally agreed to be some of the lowest residential and business rates in the State would generate additional revenue. The Public Staff stated that these additional revenues would contribute towards Pineville's continued profitability, while maintaining its ability to provide basic telephone service to all customers within its service area at affordable rates. The Public Staff further noted that, should Pineville decide it needs additional flexibility, it has the option of pursing alternative forms of regulation that could provide that needed flexibility.

The Public Staff opined that the Commission should find that it can make no assertion that it is able to predict the distant future, but, over the long term, Pineville's continued profitability will depend on the skill and insight of its management, as well as other factors which cannot now be foreseen. The Public Staff asserted that, in the immediate future, however, it appears to the Public Staff that the interconnection requested by Sprint, and the resulting competition with Sprint and Time Warner, will not place an undue economic burden on Pineville or significantly interfere with the availability of universal service to Pineville's customers. The Public Staff recommended that the Commission find that Sprint's request for termination of Pineville's exemption, under Section 251(f)(1) of the Act, from the obligations of Section 251(a) and Section 251(b), should be granted.

Analysis

Based on the foregoing, and the entire evidentiary record in this proceeding, the Commission agrees with Sprint and the Public Staff on this matter and therefore concludes that Sprint's request for Section 251(a) interconnection and Section 251(b) arrangements will not impose an undue economic burden on Pineville.

As noted earlier in this discussion, the Commission has previously established an appropriate standard of what would constitute an undue economic burden in the Sprint/Randolph proceeding. The Commission is not persuaded by the arguments of Pineville in this case that the Commission should alter its prior decision in the *Randolph* case and instead now find that a more lenient standard similar to the ones adopted recently by the North Dakota PSC and Maine PUC is appropriate.

The Commission is persuaded that Sprint's request in this instant docket will not damage Pineville economically to such an extent that its continued operation is endangered or that it will be forced to increase rates or reduce service in a way that is inconsistent with the state and national policy favoring the availability of basic telephone service to all citizens at affordable rates. The evidence shows that Pineville has been a profitable company and has been able to divert fairly large sums of money to its CLP affiliate for the last several years. In addition, Pineville's current basic local exchange rates are remarkably low; its current R1 rate is $4.77 and its current B1 rate is $10.62. The evidence also reveals that Pineville has not increased its local service rates since Pineville became subject to the Commission's jurisdiction in 1973, or 37 years ago. Further, Pineville is free to avail itself to alternative regulatory models such as price regulation plans or Subsection (h) plans, or even remain a rate-of-return company and file a rate case docket with the Commission.

The Commission finds Sprint's analysis of the potential economic harm Pineville may realize as a result of granting a partial termination of Pineville's rural exemption persuasive and finds that its analysis is based on reasonable and rational assumptions. The Commission also notes that Pineville has filed for a video franchise which will increase Pineville's ability to effectively compete head-to-head with Sprint/Time Warner Cable for customers.

CONCLUSIONS

The Commission concludes that Sprint's request for Section 251(a) interconnection and Section 251(b) arrangements will not impose an undue economic burden on Pineville.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

ISSUE NO. 6 – MATRIX ISSUE NO. 3(c): Is Sprint's request for Section 251(a) interconnection and Section 251(b) arrangements technically feasible?

POSTITIONS OF PARTIES

SPRINT: Yes. Sprint's request is technically feasible; Sprint's cable business model has been implemented in 42 states, including North Carolina, and Sprint has never been unable to implement the business model based upon technical infeasibility.

PINEVILLE: Yes. Sprint's request for Section 251(a) interconnection with Pineville is technically feasible so long as Sprint seeks to establish direct interconnection with Pineville at Pineville's existing mid-span meet point with AT&T.

PUBLIC STAFF: Yes. No evidence was presented that would indicate any technical issues that would prevent interconnecting the two networks, and Sprint's experience with interconnecting across a variety of states and with companies of varying size reflects the routine nature of these arrangements.

DISCUSSION

Sprint witness Farrar testified that the Sprint cable business model has been in operation since 2004 and, to date, operates in 42 states, in markets served by every regional Bell operating company (RBOC), most mid-sized holding companies, and at least 161 rural telephone companies, including cooperatives and municipal-owned, many of which have fewer access lines than Pineville. Witness Farrar stated that Sprint has never been unable to implement the business model for technological reasons. Witness Farrar also stated that the interconnection Sprint seeks with Pineville in this proceeding is technologically no different than Pineville's current interconnection arrangements with other carriers, including its own CLP affiliate PTC Communications.

Pineville asserted that, because no substantive negotiations have taken place between the parties, it did not know what sort of technical interconnection arrangements Sprint would propose to establish, and thus Pineville cannot yet determine if there are any issues of technical feasibility. However, Pineville stated that it has conceded that, to the extent that Sprint seeks to establish direct interconnection with Pineville at the existing mid-span meet point where Pineville's existing facilities meet those of AT&T North Carolina, Pineville does not anticipate any issue of technical feasibility regarding such interconnection.

The Public Staff stated in its Proposed Order that it agrees with Sprint that Sprint's experience in interconnecting with other companies in North Carolina, as well as other states, and with companies ranging in size from small rural telephone companies to large RBOCs, indicates that there are no technical issues likely to arise which would prevent the interconnection of the two networks.

The Commission concludes that no party presented evidence directly challenging Sprint's assertion that its request is technically feasible. Therefore, the Commission concludes that Sprint's request for Section 251(a) interconnection and Section 251(b) arrangements is technically feasible.

CONCLUSIONS

The Commission concludes that Sprint's request for Section 251(a) interconnection and Section 251(b) arrangements is technically feasible.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

ISSUE NO. 7 - MATRIX ISSUE NO. 3(d): Is Sprint's request for Section 251(a) interconnection and Section 251(b) arrangements consistent with Section 254 of the Act (other than Sections 254(b)(7) and (c)(1)(D))?

POSITIONS OF PARTIES

SPRINT: Yes. Sprint's request is consistent with the universal service goals identified in Section 254 of the Act. Sprint's economic burden analysis shows that Sprint's request does not overly burden Pineville's ability to continue to provide universal service. In addition, within TWC's footprint in which service can be offered, Sprint enables rural end users to obtain quality advanced services which are comparable to services available in urban areas. The focus of the universal service analysis should be what effect Sprint's interconnection request would have on the rural ILEC's ability to provide basic telephone service in its service territory.

PINEVILLE: No. Sprint cannot establish that its request for Subsection 251(a) interconnection with Pineville and establishment of Section 251(b) arrangements is consistent with Section 254 of the Act (other than Sections 254(b)(7) and (c)(1)(D)). Moreover, the focus should be on the service to be provided by the company requesting interconnection, not the rural ILEC, and whether that service will satisfy universal service goals.

PUBLIC STAFF: Yes. The issue of consistency with Section 254 relates to whether the rural telephone company will be able to continue providing universal service in a satisfactory manner following the interconnection, not to whether the requesting company's service satisfies universal service principles. The requested interconnection will not prevent Pineville from providing universal service to its customers.

DISCUSSION

Section 254(b)(1)-(6) sets out the relevant universal service principles that are referred to in the Subsection 251(f)(1) exemption. They are: (1) quality services at just, reasonable, and affordable rates; (2) access to advanced services; (3) access to telecommunications and information services (including interexchange and advanced services) in rural, insular, and high cost areas that are reasonably comparable to those in urban areas; (4) equitable and nondiscriminatory contributions for the preservation and advancement of universal service; (5) specific and predictable state and federal mechanisms to preserve and advance universal service; and (6) access to advanced telecommunications services for schools, health care, and libraries.

Sprint witness Farrar noted that Sprint's request for interconnection is consistent with universal service goals as set forth in Section 254, because Sprint and Time Warner will offer a wide variety of affordable services similar to those offered in urban areas in other parts of North Carolina. Witness Farrar also emphasized that in the *Randolph RAO* (at p. 15) the Commission had concluded that the issues of undue economic burden and consistency with Section 254 were closely intertwined. If the Commission finds that there is no undue economic burden on Pineville if the rural exemption is partially lifted, he argued that it stands to reason that Pineville's continued ability to provide universal service will not be unduly impaired.

Sprint witness Burt emphasized the benefits that Pineville customers would receive through competition. He stated that the introduction of voice over internet protocol (VoIP) telephone service provided jointly by Sprint and Time Warner Cable will bring various benefits to Pineville customers. Those customers will for the first time have a choice of landline telecommunications providers. Competition will tend to result in lower prices and improved service quality, as well as more and quicker innovation, as compared to the single-provider market now in force.

In contrast, Pineville witness Williams stressed what he believed would be serious adverse economic impacts on Pineville. There will be increased line and revenue losses, causing Pineville more and more difficulty in being able to provide universal service in its service area. Witness Williams also questioned the Commission's conclusion in the *Randolph RAO* that the factors to be considered in addressing the issues of undue economic burden and consistency with Section 254(b) are largely the same. Rather, the Commission should in addition consider whether the service to be provided by Sprint/Time Warner will comply with the principles set forth in Section 254(b).

More specifically, witness Williams asserted that *Sprint/Time Warner's services* would not be consistent with Section 254(b)(1). This is because these companies do not participate in LifeLine and Link-Up; do not offer local and long distance on a stand-alone basis, without bundling; and because their VoIP service is dependent on commercial power at the customer's premises. For these same reasons, Sprint/Time Warner fall afoul of Section 254(b)(3), relating to rural and high cost areas. Since Sprint does not contribute to the federal universal service fund and has offered no evidence that Time Warner does, the Sprint/Time Warner service will violate the principle of Section 254(b)(4) that all telecommunications providers must "make an equitable and nondiscriminatory contribution to preservation and enhancement of universal service," as well as the principle set forth in Section 254(b)(5) relating to specific and predictable support mechanisms. It is also not clear that the service of Sprint and Time Warner will provide access to E-911 services or 811 locate services, or that their service will be in the best interest of the public. On cross-examination, however, witness Williams acknowledged that the services he contended that Sprint and Time Warner must provide in order for their requested interconnection to be consistent with Section 254 - e.g., LifeLine and Link-Up service, stand-alone local service, service that remains available in the event of power interruption, and contribution to the universal service fund - are not services that CLPs are legally required to provide.

The Public Staff argued that the issues of undue economic burden and the ability of a rural ILEC to continue to offer service consistent with Section 254(b)(1) are closely related and must be analyzed with reference to each other. In the instant case, a finding of no undue economic burden supports the conclusion that a rural ILEC will be able to continue with its universal service obligations under the Act if the exemption is lifted and the interconnection allowed. The analysis, moreover, relates to the ability of the rural ILEC to continue with its universal service obligations rather than the requesting carrier.

The Commission believes that Sprint has carried its burden of proof on this issue. The universal service test that the Commission enunciated in the *Randolph RAO* was whether the rural ILEC "will be forced to increase rates or reduce service in a way that is inconsistent with the state and national policy favoring the availability of basic telephone service to all citizens at affordable rates." As further explained in the *Randolph RAO*, the issues of undue economic burden and consistency with Section 254 are closely related. Both the undue economic burden and the universal service standards relate to whether the rural ILEC can continue to provide services. The Commission agrees with Sprint and the Public Staff that it is eminently reasonable to infer that, if there is no undue economic burden on the rural ILEC in removing the exemption and allowing the interconnection, this is a strong indicator that the rural company will likely be able to continue providing service to its customers in a manner consistent with Section 254 following the interconnection. The Commission has found in Finding of Fact No. 5 that Sprint's request for interconnection is *not* unduly economically burdensome, so it follows that it is highly unlikely that Pineville will not be able to continue providing its services consistent with Section 254.

The Commission notes that Pineville devoted much of its argument in an attempt to frame the universal service inquiry away from the responsibilities of the rural ILEC to what it asserted were the *obligations* of the requesting carrier with respect to universal service.[1] Pineville's examples of what Sprint might not be offering if interconnection were allowed may be true, but they are also largely irrelevant. Subsection 251(f)(1)(A)'s "consistent with section 254" language obviously relates to whether the *rural ILEC* will be unduly harmed in its ability to maintain its universal service responsibilities if the exemption is removed and interconnection allowed. Thus, Subsection 251(f)(1)(A), properly construed, recognizes the responsibility for providing universal service as being squarely on the ILECs, including the rural ILECs - not the CLPs. CLPs are under no legal obligation to provide LifeLine or Link-Up services, to ensure that their power remains available during power interruptions, or to provide stand-alone local or long distance service that is not tied to a bundle. Section 251(f)(1)(A) does not provide or suggest that CLPs are to assume these traditional ILEC responsibilities in order to be eligible for interconnection with rural ILECs.

CONCLUSIONS

The Commission concludes that Sprint's request for Section 251(a) interconnection and Section 251(b) arrangements is consistent with Section 254 of the Act (other than Sections 254(b)(7) and (c)(1)(D)).

IT IS, THEREFORE, ORDERED as follows:

1. That Pineville's Section 251(f)(1) rural exemption is hereby partially terminated as requested by Sprint to allow Sprint Section 251(a) direct and indirect interconnection, Section 251(b)(2) number portability, Section 251(b)(3) dialing parity including directory listings, Section 251(b)(5) reciprocal compensation, and directory distribution;

2. That Pineville is hereby directed to enter into negotiations with Sprint in accordance with the partial Section 251(f)(1) termination granted herein; and

3. That the statutory timelines as identified in Section 252(b)(1) of the Act shall start on the effective date of this Order.

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[1] Even so, Pineville did not specifically argue in its Post-Hearing Brief what Randolph argued in the *Randolph* case. There, Randolph argued that the Commission should condition the termination of the rural exemption on a concomitant determination that Sprint/Time Warner should be required to pursue and receive designation as an eligible telecommunications carrier in all of the Randolph's service area as allowed in Section 253(f) of the Act which states: "It shall not be a violation of this section for a state to require a telecommunications carrier that seeks to provide telephone exchange service or exchange access in a service area served by a rural telephone company to meet the requirements of section 214(e)(1) for designation as an eligible telecommunications carrier for that area before being permitted to provide such service." In rejecting that argument, the Commission noted that the Act permits, but does not require, such designation. Furthermore, Randolph's argument was premised upon rejection of Sprint witness Farrar's testimony that Sprint/Time Warner will offer competitive service to all business and residential customers for whom facilities are available. The Commission also concluded that "RTC's proposal, though permitted by Section 253, is inconsistent with the pro-competitive focus of the Act and greatly expands a CLP's service obligation to include carrying out eligible telecommunications carrier responsibilities for a rural ILEC's entire service area," and that expansion of such responsibility had not been proven to be in the public interest. See, *Order Ruling on Objections*, Docket No. P-294, Sub 30 (December 31, 2008) at pp. 13-14.

ISSUED BY ORDER OF THE COMMISSION.
This the _7th_ day of December, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

bp120610.01

Appendix A

Sprint/Pineville Arbitration Proceeding
Docket No. P-120, Sub 26

Act	Telecommunications Act of 1996
ARMIS	Automated Reporting Management Information System
AT&T	BellSouth Telecommunications, d/b/a AT&T
CLEC	Competitive Local Exchange Company (Carrier)
CLP	Competing Local Provider
CMRS	Commercial Mobile Radio Service
Commission	North Carolina Utilities Commission
FCC	Federal Communications Commission
ICA	Interconnection Agreement
ILEC	Incumbent Local Exchange Company (Carrier)
LEC	Local Exchange Company (Carrier)
Pineville	Town of Pineville d/b/a Pineville Telephone Company
PSC	Public Service Commission
Public Staff	Public Staff – North Carolina Utilities Commission
PUC	Public Utilities Commission
Randolph	Randolph Telephone Company
RAO	Recommended Arbitration Order
RBOC	Regional Bell Operating Company
SEC	U.S. Securities and Exchange Commission
Sprint	Sprint Communications Company L.P.
TWC	Time Warner Cable
UNE	Unbundled Network Element
VoIP	Voice Over Internet Protocol

DOCKET NO. T-4417, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application for Certificate of Exemption to Transport Household Goods by Nevius Logistics, LLC, c/o Willie Anthony Nevius, 4642 W. Market Street, Suite 155, Greensboro, North Carolina 27407	ORDER RULING ON CERTIFICATE OF EXEMPTION

HEARD IN: Commission Hearing Room 2115, Dobbs Building, 430 N. Salisbury Street, Raleigh, North Carolina, on Thursday, December 10, 2009, at 9:30 a.m.

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

APPEARANCES:

For the Public Staff:

Tab Hunter, Staff Attorney, Public Staff - North Carolina Utilities Commission, Post Office Box 29520, Dobbs Building, Raleigh, North Carolina 27699-4325

For the Applicant:

Stephon J. Bowens, Bowens Law, PLLC., 3434 Edwards Mill Road, Suite 112-254, Raleigh, North Carolina 27612

BY THE COMMISSION: On April 20, 2009, Nevius Logistics LLC, (Nevius or Applicant) pursuant to G.S. 62-261(8) and Commission Rule R2-8.1, filed an application with the North Carolina Utilities Commission (Commission) for a Certificate of Exemption (Certificate) to transport household goods by motor vehicle for compensation within the State of North Carolina.

On May 5, 2009, Applicant filed an Amended Application for a Certificate.

On May 11, 2009, the Commission Staff provided Applicant with written acknowledgement of receipt of its Application and requesting additional information necessary for the application to be complete.

On July 31, 2009, the Applicant filed with the Commission the Confidential Criminal History Check for member-manager Willie Nevius.

On August 3, 2009, the Commission Staff advised the Applicant that additional information was required before review of his application could be completed.

On August 17, 2009, the Applicant filed a statement certifying that Willie Nevius is the only member-manager of Nevius Logistics, LLC.

On September 9, 2009, the Commission issued an Order Scheduling Hearing in the above identified docket. In the Order, the Commission advised the Applicant that it was to retain counsel and appear before the Commission in this proceeding to discuss its application for a certificate. The Commission further ordered that the Public Staff participate as a party and advised the Applicant that pursuant to G.S. 62-71, the proceeding would be a public hearing during which all matters of relevance may be discussed. The docket was scheduled for hearing on Tuesday, September 29, 2009, at 9:30 a.m., Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina.

On September 29, 2009, the Applicant appeared at the hearing without counsel in violation of the requirements of Commission Rule R1-22. The Applicant requested a continuance in the hearing to allow it to obtain counsel to represent it in this matter before the Commission. By Order issued September 29, 2009, the Commission granted the Applicant's request and indicated that once the Applicant retained counsel the docket would be rescheduled for hearing.

On October 19, 2009, Stephon J. Bowens of Bowens Law, PLLC, filed a Notice of Appearance with the Commission indicating that his firm had been retained to represent the Applicant in the docket.

On October 30, 2009, the Commission issued an Order Rescheduling Docket for Hearing. The docket was scheduled for hearing on Thursday, December 10, 2009, at 9:30 a.m., Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina.

On December 7, 2009, the Applicant filed the direct testimony of LaShelle Robinson, Kurtyce Cole, and Willie Anthony Nevius (Willie Nevius) and a Motion for Leave to have Testimony entered into the Record.

The matter came on for hearing as scheduled in Raleigh on December 10, 2009. Mr. Willie A. Nevius, member-manager of Nevius, was present with Counsel Mr. Stephon Bowens. Mr. Tab Hunter of the Public Staff was also present at the hearing.

The Applicant offered the testimony of LaShelle Robinson, Office Manager for R&R Transportation, Inc.; Kurtyce Cole, Marketing Consultant for Ardyss International; and Willie Anthony Nevius.

No protests were filed in this proceeding.

Based upon the information contained in the application, the Commission files in this docket, testimony at the hearing, and the record of this proceeding, the Commission now makes the following

TRANSPORTATION – COMMON CARRIER CERTIFICATE

FINDINGS OF FACT

1. Nevius is a Limited Liability Corporation incorporated with the North Carolina Secretary of State's Office on May 16, 2008 by Willie Nevius.

2. Willie Anthony Nevius is the sole member-manager of Nevius.

3. On April 20, 2009, Nevius filed an application with the Commission for a certificate of exemption to transport household goods for compensation. An amended application was filed with the Commission on May 5, 2009.

4. On July 31, 2009, Willie Nevius, as a member-manager, filed with the Commission information detailing his criminal arrests or convictions.

5. Such information showed criminal arrests or convictions spanning a period of at least 10 years, including convictions in the States of New Jersey and North Carolina.

6. The most recent conviction for Willie Nevius was in North Carolina; in particular, on May 2, 2005, he was convicted of Felony Speeding to Elude Arrest.

7. On September 4, 2002, Willie Nevius was convicted of two counts of Felony Assault with a Deadly Weapon (AWDW) on a Government Official and Felony Conspiracy to Possess Schedule II.

8. Willie Nevius has experience in the transportation industry. Mr. Nevius has worked informally for companies performing and transporting related services on an as - needed basis from 1994 to 1997.

9. Willie Nevius worked for R&R Transportation, Inc. (R&R), on and off from 1997 until 2007. R&R is a transportation company located at 4415 Abner Place, in Greensboro, North Carolina. R&R moves freight throughout the United States. While employed with R&R, Willie Nevius assumed a variety of duties including but not limited to a tractor trailer driver, worked in the warehouse, performed in-house moves, furniture set-ups for the furniture market, and office administration. He even performed some bookkeeping and filing for R&R for a brief period of time..

10. R&R was aware of Willie Nevius' criminal record.

11. Witness Robinson testified that during his employment by R&R, Willie Nevius' character and trustworthiness were never called into question. Mr. Nevius was entrusted with R&R's trucks and customer property valued in excess of $100,000. He was an overall excellent employee with R&R and left that job in good standing.

12. Willie Nevius was once bonded in 2006 after he started a transportation brokerage firm. The bond was for $10,000. The bond was approved through the North Carolina Department of Transportation.

13. Willie Nevius has lived in North Carolina for approximately 21 years. He currently resides in Guilford County.

14. Willie Nevius is involved in his community. He volunteers with the Salvation Army and Urban Ministries. He also helps out at the local homeless shelter serving meals to the residents. He has participated in organizing his community to take part in the 2008 Presidential election.

15. As a result of his community activities, Willie Nevius has developed a good reputation in his community.

16. Willie Nevius has four children. He has custody of these children and provides their primary support.

17. Willie Nevius is seeking a certificate of exemption to engage in household goods moves in order to increase his income.

18. In anticipation of receiving his certificate, Mr. Nevius contacted several apartment managers in the Greensboro area to solicit their support. Many of the apartment managers have expressed to him their interest in having a designated mover to refer to their tenants for local moves.

19. Willie Nevius' target market is apartment tenants throughout the greater Triad area. He has researched the greater Triad area and learned that there is a need for that service (small moves). Specifically, for his moving business he expects to target the University areas, and concentrate on college students.

20. Willie Nevius has a valid class A North Carolina Drivers license. He has access to a 14 foot box Truck and a cargo van to perform household goods moves.

21. Willie Nevius has obtained the necessary insurance to move forward with his business operation.

WHEREUPON, the Commission reaches the following:

CONCLUSIONS

On August 29, 2008, the Commission issued an Order Amending Rule R2-8.1 and Allowing Additional Comments in Docket No. T-100, Sub 69.[1] In that Order, the Commission made some modifications to Commission Rule R2-8.1. Rule R2-8.1 sets out the requirements which an applicant must meet in order to obtain a certificate of exemption to transport household goods in the State of North Carolina.

[1] *In the Matter of Petition by Movin'On Movers, Inc. to Amend Rule R2-8.1 for Certificates of Exemption; Transfers; and Notice*, Order Amending Rule R2-8.1 And Allowing Additional Comments, Docket No. T-100, Sub 69 (August 29, 2009).

The new modifications of Rule R2-8.1 require the following: that an applicant certify that the applicant will only permit employees with valid driver's licenses to operate vehicles used to transport HHG in compliance with the laws of the State of North Carolina; that applicants[1] will submit a certified 10-year criminal record check with each application; and an applicant should possess a valid form of employment authorization, regardless of citizenship status.[2]

In Docket No. T-100, Sub 69[3], the Commission stated in the case of criminal records that "if it has a concern about any information contained in the applicant's criminal record that it believes might call into question the applicant's fitness to obtain a certificate, the Commission may request additional information or schedule a hearing to allow the applicant an opportunity to be heard before any further action is taken on the application."[4]

The Commission was very clear that an applicant would not be denied a certificate automatically or solely on the basis that the applicant has a criminal record. Instead, the Commission would review and evaluate the information provided to determine if any conviction or any other aspect of the information provided is relevant to, or would call into question, the applicant's fitness to possess a certificate of exemption.[5]

The Commission further stated in that Order that it would consider a variety of factors regarding the conviction in making that determination, including, but not limited to, the severity of the crime, the date of the offense, the nature of the crime as it relates to the duties and responsibilities of a household goods mover, and the applicant's employment, rehabilitation, and other activities since the crime was committed.[6]

In compliance with Rule R2-8.1, the Commission in this docket obtained the criminal information relevant to Mr. Nevius' activities. This information called into question the Applicant's fitness to obtain a certificate of exemption. Consequently, the Commission conducted a hearing to probe the Applicant's fitness. The record of criminal activities discussed at the hearing also called into question the Applicant's fitness. The offenses are serious.

Nevertheless, after weighing all of the evidence, the Commission believes that the certificate should not be denied due to Mr. Nevius' criminal past. The Commission's decision, though entered into advisedly, is based on the fact that Mr. Nevius' indiscretions did not relate directly to property crimes. A number of years have elapsed since his most recent conviction. Mr. Nevius has presented sufficient evidence from third parties attesting to his fitness to obtain a

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[1] Id. page 27 (*citing requirement for necessity of a criminal record* - In the case of an individual or sole proprietorship, the record should be in the name of the individual completing the application. In the case of an application from a partnership or other corporate form, the Commission expects record checks to be performed on all the partners in a partnership or all the officers (members/managers) in the case of a corporation).

[2] Id. pages 27-28.

[3] Id.

[4] Id.

[5] Id. page 27.

[6] Id.

certificate. The evidence provided by witness Robinson, an employee of R&R for the past seven years, supports granting the certificate. While employed with R&R, Willie Nevius assumed a variety of duties including but not limited to a tractor trailer driver, worked in the warehouse, performed in-house moves, furniture set-ups for the furniture market, and office administration. He even performed some bookkeeping and filing for R&R for a brief period of time. Witness Cole testified that, based upon his involvement with Mr. Nevius since the Spring of 2007, (when the Obama Presidential Campaign deployed him in the Triad area in North Carolina as a field manager, at which time he met Mr. Nevius in person) he would have no reservations about Mr. Nevius' ability to manage a household goods transportation company and is certain that Mr. Nevius has the character and the commitment to serve the citizens and businesses of North Carolina well. The Public Staff, after investigation, did not recommend denial of the request for a certificate. No other party appeared to present evidence that the certificate should be denied. When balanced against these factors, evidence of incidents involving Mr. Nevius does not persuade the Commission that the Applicant is unfit to provide adequate household goods moves in the community.

Despite his criminal record, Mr. Nevius appears to have the support of many in his community. The record shows that he has been a productive and involved member of his community. He has demonstrated this through his volunteer efforts as well as with his activism in the community, encouraging residents to participate in the electorate process. The record further shows that Mr. Nevius, as a member-manager, has taken the necessary steps to make this endeavor successful. Not only does Mr. Nevius possess experience in the transportation business, he also has some familiarity with the household goods business as well. The Commission is of the opinion that the skills he learned in the transportation business may be transferable to the household goods moving industry. The Commission further recognizes that Mr. Nevius has researched the market area in which he is interested in working. He has contacted apartment-managers in the Triad area scouting for potential clients. At the present time, he has a 14 foot box truck and a cargo van to perform moves. More importantly, Mr. Nevius has secured the necessary insurance to move forward with his business endeavor.

Based upon the entire record including the testimony, which was uncontested, the Commission concludes that Nevius Logistics, LLC, should not be denied an opportunity to receive a certificate of exemption to transport household goods in the State of North Carolina due to the criminal history of Willie Anthony Nevius.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 23rd day of February, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Kc020910.01

TRANSPORTATION – RATE INCREASE

DOCKET NO. T-825, SUB 343

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of

Petition of Hilldrup Companies, Inc., d/b/a Hilldrup Moving & Storage for Fuel Surcharge On Hourly-Rated Household Goods Moves	)))	ORDER DENYING HOURLY-RATED MOVE FUEL SURCHARGE

BY THE COMMISSION: On June 10, 2008, Hilldrup Companies, Inc., d/b/a Hilldrup Moving & Storage (Hilldrup or Petitioner) filed a petition requesting the implementation of a fuel surcharge on all North Carolina intrastate, household goods (HHG), hourly-rated shipments (i.e., moves of 35 miles or less) governed by the Commission's Maximum Rate Tariff No. 1 (MRT). Hilldrup proposed a maximum fuel surcharge for hourly-rated shipments in an amount that would be equivalent to 35 times the weight/distance move fuel surcharge in effect at the time the move is booked with the client. Presently, the Commission has only authorized and approved a fuel surcharge that may be assessed on all North Carolina intrastate, household goods, weight/distance shipments (i.e., moves greater than 35 miles) governed by the MRT.[1]

On July 11, 2008, the Commission issued an Order Requesting Comments from all Commission-certificated HHG carriers, the Public Staff – North Carolina Utilities Commission (Public Staff), the Office of the Attorney General (Attorney General), and any other interested parties regarding Hilldrup's petition.

Comments were filed by James G. Dunnagan, d/b/a Dunnagan's Moving & Storage; Charlotte Van & Storage Co., Inc.; De Haven's Transfer & Storage, Inc.; Hilldrup; and the Public Staff. The three HHG carriers who submitted comments, in addition to Hilldrup, supported the Petitioner's hourly-rated move fuel surcharge proposal including the methodology for calculating the maximum charge.

In its comments, the Public Staff indicated support for the implementation of an hourly-rated move fuel surcharge. However, the Public Staff suggested that an hourly-rated move fuel surcharge should be applied, as close as reasonably possible, to the actual number of miles driven, rather than just simply by applying the 35-mile maximum, to develop the maximum charge to the customer, as proposed by the Petitioner. Furthermore, the Public Staff observed that there is a lack of operational data and characteristics available to measure increased fuel costs for hourly-rated moves. The Public Staff suggested that one factor that may be significantly different between hourly-rated moves and weight distance moves is the "Bill of Lading Miles Gross Up Factor", which could have a substantial impact on the calculation of an hourly-rated move fuel surcharge. The Public Staff explained that the current weight/distance move fuel surcharge was developed using a "Bill of Lading Miles Gross Up Factor" that was calculated from actual data provided by cost study carriers. The Public Staff offered to assist

[1] The currently approved fuel surcharge that may be charged on weight/distance shipments is a maximum rate of $0.94 per bill of lading mile, as authorized by Commission Order issued on March 23, 2010 in Docket No. T-825, Sub 345.

carriers in the development of cost figures to determine a cost-based fuel surcharge for hourly-rated moves, if the necessary information could be provided by a sampling of carriers.

On December 2, 2008, the Commission issued an Order requesting that the Public Staff file such a study. The Order also allowed for comments regarding the Public Staff's study to be filed thereafter by any interested parties. The Public Staff was requested to include in the study a proposed hourly-rated move fuel surcharge, the methodology for applying it to hourly moves, explanations of the various issues addressed in the study, how the study was conducted, and any other relevant matters to be considered by the Commission.

On March 2, 2009, the Public Staff filed its study and reported the findings gleaned from the fuel-use data that was evaluated and analyzed. The Public Staff concluded that since mileages are not identified or tracked for hourly-rated moves, a fuel surcharge per move would be appropriate and should be based upon the costs associated with an average move. The Public Staff recommended approval of a fuel surcharge for hourly-rated moves and provided a Fuel Surcharge Index Chart (Exhibit B of its filing) which presented each of the specific proposed fuel surcharges per hourly-rated move that would be applicable per move for a particular fuel index price range. For example, if the current composite cost of fuel was $2.07, then as provided in the Fuel Surcharge Index Chart this cost would fall within the $2.0663 and $2.1118 fuel index price range and, accordingly, the proposed maximum fuel surcharge that could be levied on a per move basis at that time would be $4.00.

No comments on the study results were subsequently filed by any interested parties.

HOURLY-RATED MOVE FUEL SURCHARGE STUDY

The Public Staff stated that it selected HHG carriers to participate in its fuel-use study based upon operational information provided by HHG carriers in their 2007 annual reports submitted to the Commission. Using such information, the Public Staff identified HHG carriers that performed a large number of hourly moves in comparison to their total moves, as well as carriers who performed a significant number of hourly moves (500 or more) during the year; and from these identified HHG carriers, 24 carriers from across the state were selected. Then, the 24 selected carriers were mailed a letter requesting that they participate in the study. The mailing included a form for the HHG carriers to record operational data for hourly moves. The form required the selected carriers to determine the street miles from the location of their equipment to the origin address; the origin address to the destination address; the destination address back to the location of the carrier's equipment; and to acknowledge any multiple vehicles situations. In addition to completing the forms and then returning them to the Public Staff, the HHG carriers were asked to provide a copy of quarterly tax forms that some HHG carriers are required to file with the North Carolina Department of Revenue for its International Fuel Tax Administration Program. According to the Public Staff, information contained in the requested quarterly tax forms would provide the data and factors needed in calculating a fuel surcharge. This effort resulted in responses being provided from 20 HHG carriers who chose to participate in the study. Those 20 carriers submitted information on a cumulative total of 819 hourly-rated moves.

TRANSPORTATION – RATE INCREASE

Based upon the information provided by the HHG carriers for the 819 sampled moves, the Public Staff determined that an average move[1] would consist of one where a carrier would be driving 43.144 miles to perform an hourly-rated move, using a vehicle that has a fuel consumption rate of 7.887 miles per gallon, which would result in 5.471 gallons (43.144 miles ÷ 7.887 miles per gallon = 5.47027 gallons) of fuel being consumed in an average hourly-rated move. The Public Staff concluded that a fuel-use mix consisting of 80.54% diesel and 19.46% gasoline, which is the mix currently used in developing a weekly composite cost of fuel for calculating the fuel surcharge for weight/distance moves, would also be appropriate to use in calculating a fuel surcharge for hourly-rated moves. The Public Staff selected the composite cost of fuel of $1.358 per gallon as the starting point for determining the increase in fuel cost to be recovered through a surcharge. This composite price of $1.358 was selected because it was the composite price of fuel on December 20, 2002, just days before the MRT went into effect on January 1, 2003. Using the information provided by the 20 participating HHG carriers, and the selection of the beginning composite fuel price of $1.358, the Public Staff developed a Fuel Surcharge Index Chart for hourly-rated moves (Exhibit B of its March 2, 2009 filing), which lists a maximum fuel surcharge, per hourly-rated move, for each of 121 composite fuel index price ranges. Specifically, in its Exhibit B, the Public Staff provided a chart showing its proposed fuel surcharge per hourly-rated move in 25¢ increments, ranging from $0 to $30.00 to be levied on a per move basis, depending upon the composite index price of fuel and where it falls within the specified 121 fuel index price ranges identified in the chart.

Additionally, in its filing, the Public Staff acknowledged that while conducting the study, several of the HHG carriers involved in the study stated that they did not see a need for an hourly-rated move fuel surcharge and that they would not be using it. They explained to the Public Staff that they would simply continue to adjust their discounts on the maximum rates in the MRT to account for changing fuel prices; and they remarked that most HHG carriers do not charge the maximum rates in the MRT and instead discount the rates to varying degrees. Further, the Public Staff observed that while the study carriers' responses suggest that the HHG carriers would not be interested in charging an hourly-rated move fuel surcharge, it is likely that they may become interested in such a surcharge if and when fuel prices increase, for example, similar to what they were in the summer of 2008.

In conclusion, the Public Staff recommended that the Commission should approve an hourly-rated move fuel surcharge to be levied on a per move basis; and, if such a surcharge is implemented, then the Public Staff should monitor fuel prices and recommend decreases to the surcharge, when appropriate; and the HHG carriers should monitor fuel prices and recommend increases to the surcharge, when appropriate.

WHEREUPON, the Commission reaches the following

[1] In its March 2, 2009 filing, the Public Staff explained that since mileages are not identified or tracked for hourly-rated moves, a fuel surcharge per move would be appropriate and should be based upon the costs associated with an average move. The Public Staff acknowledged that there would be moves in which the hourly-rated move fuel surcharge would not cover the extra cost for fuel (e.g. longer distance moves); and conversely, there would also be moves for which the hourly-rated move fuel surcharge would overcompensate the carrier (e.g. shorter distance moves). However, the Public Staff contended that a fuel surcharge per move based upon the costs associated with the average move should result in the overall experience by any carrier being the reasonable recovery of increased fuel expenses over the course of time.

CONCLUSIONS

The Commission is mindful that fuel expense may be a significant cost for HHG carriers in performing both hourly-rated and weight/distance moves. Furthermore, the Commission is of the opinion that the fuel surcharge on weight/distance moves[1] has proven to be an effective means of addressing the issue of fluctuating fuel costs for weight/distance moves. However, with respect to the proposals for an hourly-rated move fuel surcharge, as requested by Hilldrup or as suggested by the Public Staff, the Commission finds and concludes that neither of these proposals are necessarily appropriate, equitable methods for applying a fuel surcharge to hourly-rated moves.

In particular, the Petitioner's proposal appears to be a methodology that would overcharge the shipper. As stated previously, the Petitioner proposed a maximum fuel surcharge for hourly-rated moves of an amount equal to 35 times the weight/distance fuel surcharge in effect at the time the move is booked with the client. For example, given the currently approved weight/distance move fuel surcharge of $0.94 per bill of lading mile, $32.90 would be the maximum fuel surcharge for an hourly-rated move under the methodology proposed by the Petitioner ($0.94 per mile × 35 miles = $32.90). However, the total actual composite fuel cost for an average hourly-rated move would only be $15.78, based upon the current composite index price of fuel of $2.885 per gallon and the average hourly-rated move fuel consumption of 5.471 gallons as determined in the Public Staff's study. Under such scenario, the Petitioner's proposed maximum fuel surcharge for an hourly-rated move would be approximately 200%, or two times the total actual composite cost of fuel for an average move; and if one considered the composite price of fuel of $1.358 on December 20, 2002, as the starting point for determining the increase in fuel cost to be recovered through a surcharge, the calculated potential over-recovery by the carrier would be even greater. The results would be similar at other weight/distance move fuel surcharge values as well. The Commission concludes that the Petitioner's request is inappropriate and should be denied.

The Commission is of the opinion that the Public Staff's proposed maximum hourly-rated move fuel surcharge to be levied on a per move basis,[2] although more reasonable than that proposed by the Petitioner, is unnecessary and unwarranted. As pointed out by the Public Staff, mileages are not identified or tracked for hourly-rated moves, so the Public Staff developed its proposal based on costs associated with an average move, including travel time from the HHG carrier's warehouse to origin and return travel back to the warehouse. The Public Staff concluded that an average move would consist of one where a carrier would be driving 43.144 miles to perform an hourly-rated move. However, under such average move methodology, there may be moves in which the Public Staff's proposed hourly-rated move fuel surcharge would not cover the extra cost for fuel (e.g. longer distance moves) and the customer

[1] The weight/distance move fuel surcharge is a supplement to the MRT and it is typically adjusted more frequently than annually based upon requests coming before the Commission for a change (increase or decrease) to be approved based upon current fuel prices. The Commission-approved, maximum fuel surcharge rate for weight/distance moves is applied only to the number of bill of lading miles; and it is assessed only once per shipment regardless of the number of vehicles used.

[2] Initially, the Public Staff supported an hourly-rated move fuel surcharge and suggested that an hourly-rated move fuel surcharge should be applied, as close as reasonably possible, to the actual number of miles driven.

might be undercharged. Conversely, there may also be moves in which the Public Staff's proposed hourly-rated move fuel surcharge would overcompensate the carrier (e.g. shorter distance moves) and the customer might be overcharged. No comments were filed by the HHG carriers in response to the Public Staff's proposal which clearly provided for a much lower proposed fuel surcharge than that proposed by Hilldrup which had been supported by the three HHG carriers who initially filed comments in this docket. Additionally, as pointed out by the Public Staff in its study filing, several of the HHG carriers involved in the study stated that they did not see a need for an hourly-rated move fuel surcharge and that they would not be using it. They explained that they would simply continue to adjust their discounts on the maximum rates in the MRT to account for changing fuel prices. The Commission is not persuaded that the Public Staff's proposed hourly-rated move fuel surcharge to be levied on a per move basis is an appropriate mechanism to adopt.

Furthermore, the Commission is aware that under presently approved Commission procedures, the many labor, material, and other rates in the MRT, including the hourly rates for both regular time and overtime applicable for moving vans and crew for hourly moves, are adjusted annually based upon the Implicit Price Deflator (IPD) of the Gross Domestic Product (GDP), which is a measure of the change in prices of all new, domestically produced, final goods and services in the United States' economy.[1] The maximum hourly rates currently in effect, as set forth in Rule 53 of the MRT, for regular time hours are: $128.15-Van & 2 Men; $165.45-Van & 3 Men; $202.70-Van & 4 Men; $240.00-Van & 5 Men; and $37.25 each additional man; and the hourly charges currently approved for overtime hours are: $159.95-Van & 2 Men; $210.95-Van & 3 Men; $262.00-Van & 4 Men; $313.00-Van & 5 Men; and $51.00 each additional man. In addition, for hourly-rated moves, as provided for in the MRT in Rule 53, the HHG carrier who provides such services is also allowed to charge the shipper a maximum of one hour travel time (from carrier location to shipper location) for each 50 miles traveled. For example, if the HHG carrier traveled 30 miles to get to the shipment's origin and 30 miles for return, the HHG carrier could additionally charge for two hours of travel time; and if that move was conducted during regular hours (8:00 am – 5:00 pm, Monday through Friday) using a van and two men that would equate to a possible additional maximum charge of $256.30. The Commission is of the opinion that the current hourly rates, as established in Rule 53 of the MRT, are sufficient to cover the costs incurred for moves of 35 miles or less.

After careful consideration, the Commission believes that the maximum rates in the MRT are adequately providing for the recovery of all costs and the opportunity for earning a reasonable profit, especially given that the rates in the MRT are increased annually based upon the IPD of the GDP. The Commission is not convinced by the record in this proceeding that it would be appropriate and fair to adopt either of the subject proposals. Therefore, the Commission finds and concludes that a fuel surcharge for hourly-rated moves of household goods should not be implemented.

IT IS, THEREFORE, ORDERED that the request by Hilldrup for an hourly-rated move fuel surcharge maximum on all North Carolina intrastate, household goods, hourly-rated

[1] Per Order Ruling on Motions and Comments, issued July 25, 2002, in Docket No. T-100, Sub 49, the Commission concluded that annual increases in the MRT should be based upon the IPD of the GDP and the increases should be on an annual basis on a specific date.

shipments governed by the MRT, as well as the Public Staff's proposal in this regard shall be, and the same are hereby, denied.

ISSUED BY ORDER OF THE COMMISSION.
This the 1st day of April, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Patricia Swenson, Deputy Clerk

br033110.01

DOCKET NO. W-218, SUB 315

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Stan Coleman, M.D., 2165 Belle Vernon Ave., Charlotte, North Carolina 28210, Complainant v. Aqua North Carolina, Inc., Respondent	))))))))	ORDER DENYING HEARING AND GRANTING SUMMARY JUDGMENT

BY THE COMMISSION: On August 3, 2010, Stan Coleman, M.D., (Complainant) filed *pro se* a formal complaint against Aqua North Carolina, Inc. (Aqua or Respondent), alleging unfair and unreasonable water and sewer rates for his subdivision of Park South Station (PSS). On September 7, 2010, the Commission issued an Order Serving Complaint in the above-captioned proceeding.

On September 23, 2010, Respondent filed its answer to the complaint. On September 27, 2010, the Commission issued an Order Serving Answer and Motion to Dismiss.

On September 28, 2010, Complainant filed his response to Respondent's answer. In his response, Complainant again asserts that the rates charged by Respondent are unjust and unreasonable and that he is entitled to have his claims pursued in a formal complaint proceeding in which he requests a hearing be held.

On October 7, 2010, Complainant made an additional filing in which he notifies the Commission that the Respondent's answer is not satisfactory to him and he requests a hearing in order to present evidence in support of his complaint.

The Commission has reviewed all filings made in the docket by both parties and views Respondent's answer and request to dismiss the complaint as a motion for summary judgment.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

After a full review of each of the filings in this docket and the allegations of fact and law made herein, the Commission concludes that Respondent is entitled to summary judgment in this matter.

"Summary judgment is the device whereby judgment is rendered if the pleadings, depositions, interrogatories, and admissions on file, together with any affidavits, show that there is no genuine issue as to any material fact and that a party is entitled to a judgment as a matter of law." Johnson v. Phoneix Mut. Life Ins. Co., 300 N.C. 247, 266 S.E.2d 610 (1980).

Complainant cites a number of statutes and lists a number of acts of alleged misfeasance and malfeasance on the part of the PSS developer, Aqua, and its predecessor Heater, the Public Staff and the Commission itself and/or its staff in support of the relief he requests. Complainant alleges, inter alia, that Respondent should never have received a Certificate of Public Convenience and Necessity (CPCN) from the Commission for the PSS water and sewer system located within the Charlotte city limits, for which Charlotte Mecklenburg Utilities (CMU) provides wholesale water and sewer service, that Respondent's rates to the PSS ratepayers are excessive and discriminatory and that the PSS residents pay municipal or county taxes but are denied municipal water and sewer retail services. Complainant seeks reclassification of commercial connections to a residential rate schedule.

Complainant has failed to cite any law or facts that justify relief on the theory that the CPCN under which Respondent serves the PSS ratepayers was unlawfully issued. Respondent was granted the CPCN on December 18, 2007 in Docket No. W-274, Sub 653. The water and sewer systems had been installed by the subdivision developer, which contracted to sell them to Aqua, a common practice in this state. The contract between the developer and Respondent addressing compensation and collection and disposition of connection fees contains features not unusual for such transactions. No evidence was presented that any other public utility desired to obtain the CPCN or provide service. Although the City of Charlotte, or its utility subunit, CMU, would have needed no CPCN from the Commission to obtain the systems or to serve within PSS, Complainant provides no allegations or evidence that retail municipal service to all PSS consumers was an option then or is an option now. Complainant identifies no provider other than Respondent ready, willing and able to provide service in 2007 or at any time thereafter.

Complainant is distressed that Respondent has operating authority but offers no alternative operator. If it is Complainant's desire that CMU provide service directly to all PSS consumers, his complaint must be made to CMU. Should CMU desire to serve, CMU needs no Commission approval. Before Respondent could be replaced as the holder of the CPCN issued by order of the Commission in 2007 in favor of another water or sewer utility regulated by the Commission, Complainant must show that Respondent has failed to fulfill its public utility responsibilities and obligations. This is not the crux of Complainant's grievances.

To the extent Complainant asserts discrimination because he pays municipal or county taxes without receiving full municipal services, his complaint is one against the governmental unit to which he pays taxes and is one for which this Commission cannot grant relief. The fact that end use water and sewer service was provided or was to be provided by a supplier other than CMU was known or should have been known by Complainant before he acquired property in PSS. Representations to Complainant by the developer, the seller of Complainant's lot, the HOA or others not subject to the Commission's jurisdiction are a matter over which the Commission has no authority.

Complainant asserts that Respondent's rates to PSS ratepayers are excessive on the theory that Respondent acquires bulk water and sewer service from CMU and provides few services and incurs few costs on its own. Rates to PSS customers were established on April 8, 2009 in Docket No. W-218, Sub 274 based on Respondent's North Carolina system-wide costs and expenses. The authorized rate of return of 8.09% was established on

Respondent's North Carolina system-wide rate base. The rates to PSS do not reflect the PSS stand-alone costs. Establishment of rates in this manner has substantial precedent in this and other jurisdictions. As required by statute, rates in this state are established on the basis of "net" not "gross" profits, and Complainant makes no allegations that Respondent's North Carolina system-wide profits are excessive.

Respondent's rates were based on a settlement agreement executed on behalf of consumer representatives. Several Aqua customers objected to establishing rates for Aqua to be charged consumers like Complainant on a system-wide basis; however, no party advocating this position intervened to formally espouse this position or to appeal a decision rejecting it. The order was not appealed. The statutes cited by Complainant notwithstanding, the rates are now deemed just and reasonable. Complainant cannot collaterally challenge the orders establishing the rates at this late date.

Complainant has failed to allege facts suggesting that Respondent is now earning excessive returns on its North Carolina system-wide costs and expenses so as to warrant a rate adjustment proceeding addressing prospective rates. Moreover, Complainant has failed to allege facts or cite legal authority for the proposition that connections served under a commercial rate schedule should be reclassified to a residential one outside the context of a general rate case.

The Commission has reviewed each allegation and contention in Complainant's formal complaint and each of his other submissions, and operating on the assumption that each allegation of fact is true, concludes that Complainant has failed to state a claim upon which relief can be granted.

"The Utilities Commission is a court of record with the powers of a court of general jurisdiction as to all matters properly before it." *North Carolina Utilities Commission v. Atlantic Coast Line R. Co.*, 224 N.C. 283, 29 S.E.2d 912 (1944). "The state [U]tilities [C]ommission, created by General Assembly, is an administrative agency of state with supervisory or regulatory and judicial powers given it by statute." *North Carolina Utilities Commission v. Atlantic Greyhound Corp.* 224 N.C. 293, 29 S.E.2d 909 (1944). "An appeal from an Order of the Corporation Commission (now, Utilities Commission), to be valid, must have been taken within the time prescribed by law, and the records of the Commission, which,... is a court of record, must show that it has been duly taken." *North Carolina Corp. Commission v. Southern Ry. Co.*, 185 N.C. 435, 117 S.E.2d 563 (1923).

G.S. 62-90(a) sets forth the appeal rights of an interested party of any Commission final order or decision. Specifically, the statute indicates the following:

> Any party to a proceeding before the Commission may appeal from any final order or decision of the Commission within 30 days after the entry of such final order or decision, or within such time thereafter as may be fixed by the Commission, not to exceed 30 additional days, and by order made within 30 days, if the party aggrieved by such decision or order shall file with the Commission notice of appeal and exceptions which shall set forth specifically the ground or grounds on which the aggrieved

party considers said decisions or order to be unlawful, unjust, unreasonable or unwarranted, and including errors alleged to have been committed by the Commission.

At the time that the Commission issued its Order Granting Franchise and Approving Rates for Service in Park South Station Subdivision in Docket No. W-274, Sub 653 on December 18, 2007, there is no evidence in the record that Complainant or any party acting on his behalf invoked a right to appeal the Commission's order.[1] Moreover, when the Commission issued its Order Granting Partial Rate Increase and Requiring Customer Notice in Docket Nos. W-218, Sub 274 and W-224, Sub 15, on April 30, 2009, there is no indication that Complainant or any party acting on his behalf invoked a right to appeal the Commission's decision at that time. It is well established that "[a]n order of State Utilities Commission is prima facie just and reasonable." State ex rel. North Carolina Utilities Commission v. Casey, 245 N.C. 297, 96 S.E.2d 8 (1957). "Valid determinations made by administrative agencies in their judicial or quasi-judicial capacities are not subject to collateral attack." State ex rel. Utilities Commission v. Carolina Coach Co., 260 N.C. 43, 132 S.E.2d 249 (1963).

Based upon the foregoing, the Commission concludes that there is no genuine issue as to any material fact in this docket and Respondent is entitled to judgment as a matter of law. Therefore, Complainant's request for a hearing is denied and the complaint at issue in this docket is dismissed.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 27th day of October, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Commissioner William T. Culpepper, III did not participate in the issuance of this order.

Cf102710.03

[1] If Complainant was not a property owner of Park South Station at the time the CPCN was issued, he nevertheless bought the property with actual or constructive knowledge of the service provider.

DOCKET NO. W-1054, SUB 12

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

Request by Environmental, Inc., Post Office Box 954, Cullowhee, North Carolina, 28723, Emergency Operator of the Holly Hills Water System, for Authority to Increase Rates and Assess the Customers	)	ORDER APPROVING INTERIM RATE INCREASE AND ASSESSMENT, SCHEDULING HEARING, AND REQUIRING CUSTOMER NOTICE

BY THE COMMISSION: On June 3, 2010, the Public Staff filed its Motion to Approve Interim Rate Increase and Assessment, Schedule Hearing on Rates and Assessment, and Require Customer Notice. In its motion, the Public Staff requested that the Commission issue an order (1) approving, on a provisional basis, an increase in monthly rates to ensure adequate monthly revenue to cover ongoing routine operating costs, (2) approving, on a provisional basis, a monthly assessment to recover $4,091 for past operating losses and past due Duke Energy bills, (3) deferring action on any assessments for additional improvements to the water system, (4) scheduling a hearing on the rates and assessment, and (5) requiring customer notice.

In support of its Motion, the Public Staff stated:

1. By Order dated January 28, 2008, the Commission approved the appointment of Wike Operations, Inc. (Wike), as emergency operator of the Holly Hills Water System (Holly Hills or System) in Jackson County, North Carolina. The Order approved the continuation of the rates previously approved for Environmental Maintenance, Inc., of a $20.00 base monthly charge for zero usage, and $2.75 per 1,000 gallons of water used.

2. By letter filed with the Commission on February 6, 2008, Wike requested authority to charge each of the 25 customers a one-time surcharge of $118 to cover the $2,950 cost of performing required water quality testing. In addition, Wike requested approval of a monthly assessment of $13.88 to be applied to each customer's bill for an 18-month period. The proposed $6,245 assessment was intended to cover the estimated cost of making necessary replacements and upgrades to the system.

3. By Order dated June 3, 2008, the Commission approved the requested surcharge and 18-month assessment.

4. By Order dated November 23, 2009, upon the request of Wike to be replaced as emergency operator and based upon the recommendation of the Public Staff, the Commission appointed Environmental, Inc. as the new emergency operator.

5. The Order provided that "The Public Staff will need to perform a final audit of the records of Wike Operations, Inc., to ensure an appropriate accounting transition from one emergency operator to another."

6. The Order further provided that the previously approved rates should be approved on a provisional basis, subject to true-up upon subsequent review and approval of the actual cost of operating the water system.

7. The Public Staff's audit of the data provided by Wike and the subsequent data provided by Environmental, Inc., revealed that the annual revenues for the System are not sufficient to cover the routine operating expenditures. The revenues and expenses for Environmental, Inc., since it was appointed as emergency operator were shown on the Public Staff Exhibit I, Schedule 1, which was attached to the Motion. The Exhibit showed that, since it took over operation of the System in November 2009, Environmental, Inc., incurred a net operating loss of $2,077 as of March 31, 2010.

8. Environmental, Inc.'s $2,077 operating loss includes its capital expenditures to keep the System functioning properly, such as replacement of the booster pump and the birm in the filter. There is also an electric bill of $2,014 owed to Duke Energy primarily for service to the main well pump, which was back-billed to Wike for 18 months of service.[1/] The total of $4,091 is currently owed by Holly Hills to the emergency operator and Duke Energy. In addition, approximately $3,000 to $4,000 of minimal improvements to the filtering system is currently needed to better control the iron in the System.

9. Based on the Public Staff's analysis of Environmental Inc.'s ongoing expenses, which were shown on Public Staff Exhibit I, Schedule 2 attached to the Motion, the Public Staff recommended that the current base monthly charge of $20.00 for zero usage should be increased to $30.00, and the usage charge, per 1,000 gallons, should be increased from $2.75 to $4.39. This would increase the average monthly bill for 4,000 gallons of usage from $31.00 to $47.56.

10. The Public Staff recommended a monthly assessment of $24.35for 6 months to each of the existing 28 customers, which would produce sufficient funds to address the existing $4,091 of outstanding debt.

11. Although there are other capital upgrades needed to ensure the proper ongoing operation of the System, the Public Staff recommended that capital expenditures be limited, since it is probable that the Holly Hills water system will be replaced with a system to be extended by Tuckaseigee Water and

[1/] Duke Energy bills Holly Hills for service to two accounts, the main well pump and a booster pump, by separate bill. Wike received bills for the smaller account, the booster pump station, for the entire time it served as emergency operator. Due to administrative oversight, Duke failed to send a bill for the main well pump electric account for approximately 18 months after the first bill received by Wike.

Sewer Authority (TWSA). The Public Staff stated that it was informed that TWSA hopes to complete this extension by the end of 2010.

12. The Public Staff recommended that the rates and assessment be approved on a provisional basis subject to adjustment and true-up of any amounts found unjust or unreasonable after notice and hearing.

13. The Public Staff recommended that action with regard to assessment for any additional proposed capital improvements to the system be deferred pending notice and hearing.

14. The Public Staff recommended that the Commission seek input from customers at a customer hearing regarding whether an additional $3,000 to $4,000 in improvements should be made to the filter system, as a temporary measure, until TWSA is able to complete installation of its system, as these expenses would result in an additional assessment of $100 to $150 per customer.

15. The Public Staff recommended that the Commission schedule a hearing as soon as practicable on the rates and the assessment and require customer notice.

Based upon the foregoing, the Commission is of the opinion that good cause exists to issue an order as requested by the Public Staff.

IT IS, THEREFORE, ORDERED as follows:

1. That the rates and assessment reflected on Appendix B attached hereto are hereby approved for Environmental, Inc., on a provisional basis, and are subject to adjustment and true-up of any amounts found unjust or unreasonable after notice and hearing.

2. That action with regard to any possible additional capital expenditures and assessments for improvements to the system is deferred pending notice and hearing.

3. That the Commission shall seek input from customers of the Holly Hills water system regarding whether additional expenditures for improvements to the filter system should be made prior to the probable transfer of service to TWSA.

4. That a hearing on the surcharge and the assessment is scheduled for 7:00 p.m., on Tuesday, August 3, 2010, in the Jackson County Courthouse, Justice & Administration Building, Courtroom #1, 401 Grindstaff Cove Road, Sylva, North Carolina.

5. That a copy of Appendix A attached to this Order shall be mailed with sufficient postage or hand delivered by Environmental, Inc., to all customers in the Holly Hills Subdivision no later than 10 days after the date of this Order; and that Environmental, Inc., submit to the Commission the attached Certificate of Service properly signed and notarized not later than 20 days after the date of this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 22nd day of June, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

rb062210.03

·Commissioner ToNola D. Brown-Bland did not participate.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

APPENDIX A
PAGE 1 OF 2

NOTICE TO CUSTOMERS
DOCKET NO. W-1054, SUB 12
BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

NOTICE IS HEREBY GIVEN that based upon the request of Environmental, Inc. (Emergency Operator of the Holly Hills Water System), and the recommendation of the Public Staff, the Commission has approved (1) on a provisional basis, an increase in monthly rates to insure adequate monthly revenue to cover ongoing routine operating costs, (2) on a provisional basis, a monthly assessment to recover year to date operating losses ($2,077) incurred due to cost of capital improvements already performed by Environmental, Inc., and payment for 18 months of past due electric bills for the main well pump ($2,014).

The Public Staff's audit of data provided by Wike Operations, Inc., the former emergency operator, and subsequent data provided by Environmental, Inc., reveals that the annual revenues for the system are not sufficient to cover the routine operating costs. The Public Staff has therefore recommended that the current base monthly charge for zero usage of $20.00 be increased to $30.00, and the usage charge, per 1,000 gallons, be increased from $2.75 to $4.39. This results in an increase in the average monthly bill for 4,000 gallons of usage from $31.00 to $47.56.

The Public Staff reported to the Commission that the $2,077 operating loss was incurred due to capital expenditures made by Environmental, Inc., since taking over in November of 2009, including replacement of the booster pump and replacement of the birm in the filter. The past due amount of $2,014 for electric service is a settlement amount agreed to by Duke Energy for previous electric service to the main well pump, which was billed on a separate account. A higher bill for this electric account was back-billed to the previous emergency operator after Duke Energy failed to bill for 18 months due to administrative oversight. The total amount of $4,091 ($2,077 + $2,014), spread over six monthly assessments to 28 customers results in a monthly assessment of $24.35. Environmental, Inc., has also indicated that an additional $3,000 to $4,000 will be needed for minimal short-term improvements to the iron filtration system, which would result in an additional assessment of $100 to $150 per customer; however, the Public Staff is not recommending that these expenses be included at this time.

APPENDIX A
PAGE 2 OF 2

There are other capital upgrades needed to insure the proper ongoing operation of the system; however, it is planned that the Holly Hills water system will be replaced with a system to be extended by Tuckaseigee Water and Sewer Authority (TWSA). TWSA hopes to complete this extension by the end of 2010. It was therefore recommended by the Public Staff that additional capital expenditures be limited.

The matter has been scheduled for customer hearing at 7:00 p.m., on Tuesday, August 3, 2010, in the Jackson County Courthouse, Justice and Administration Building, Courtroom #1, 401 Grindstaff Cove Road, Sylva, North Carolina.. At the customer hearing, the Commission will seek input from the customers regarding the new rates and assessment, and regarding whether or not an additional $3,000 to $4,000 in minimal improvements should be performed on the iron filtering system.

The Public Staff is authorized by statute to represent consumers in proceedings before the Commission. Written statements to the Public Staff concerning the new rates and assessment should be addressed to Mr. Robert Gruber, Executive Director, Public Staff, 4326 Mail Service Center, Raleigh, North Carolina, 27699-4326. Written statements can also be faxed to (919) 715-6704 or e-mailed to jerry.tweed@psncuc.nc.gov.

The Attorney General is also authorized by statute to represent consumers in proceedings before the Commission. Statements to the Attorney General should be addressed to The Honorable Roy Cooper, Attorney General, c/o Utilities Section, 9001 Mail Service Center, Raleigh, North Carolina 27699-9001.

This the 22nd day of June, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

APPENDIX B

SCHEDULE OF RATES
for

ENVIRONMENTAL, INC.

(Emergency Operator)

for providing water utility service in

HOLLY HILLS SUBDIVISION

Jackson County, North Carolina

Residential Metered Monthly Rates:

Base charge, zero usage	$ 30.00
Usage charge per 1,000 gallons	$ 4.39

Monthly Assessment: $ 24.35

Assessment for a six month period beginning July 2010 and ending December 2010

Connection Charge: $1,750 per connection

Reconnection Charge:

If water service cut off by utility for good cause:	$10.00
If water service cut off by utility at customers request:	$ 5.00

Bills Due:	On billing date
Bills Past Due:	15 days after billing date
Billing Frequency:	Shall be monthly for service in arrears
Finance Charges for Late Payment:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-1054, Sub 12, on this the 22nd day of June, 2010.

WATER AND SEWER – EMERGENCY OPERATOR

CERTIFICATE OF SERVICE

I, ______________________________________, mailed with sufficient postage or hand delivered to all affected customers the attached Notice to Customers issued by the North Carolina Utilities Commission in Docket No. W-1054, Sub 12, and the Notice was mailed or hand delivered by the date specified in the Order.

This the _____ day of ____________________, 2010.

By: ______________________________
Signature

____
Name of Utility Company

The above named Applicant, ______________________________, personally appeared before me this day and, being first duly sworn, says that the required Notice to Customers was mailed or hand delivered to all affected customers, as required by the Commission Order dated __________________ in Docket No. W-1054, Sub 12.

Witness my hand and notarial seal, this the ____ day of ______________, 2010.

____
Notary Public

____
Address

(SEAL) My Commission Expires: ______________________________
Date

DOCKET NO. W-1054, SUB 12

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Environmental Maintenance Systems, Inc. -- Request by Environmental, Inc., Emergency Operator of the Holly Hills Water System, for Authority to Assess the Customers	)))))	RECOMMENDED ORDER APPROVING RATES AND ASSESSMENT AND REQUIRING CUSTOMER NOTICE

HEARD IN: The Justice Administration Building, 401 Grindstaff Cove Road, Sylva, North Carolina, on Tuesday, August 3, 2010.

BEFORE: Hearing Examiner, Ronald D. Brown

APPEARANCES:

For the Applicant, Environmental, Inc.

No Attorney of record

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 HEARING EXAMINER: By Order dated November 23, 2009, upon the request of Wike Operations, Inc. (Wike Operations), to be replaced as emergency operator, and based upon the recommendation of the Public Staff, the Commission appointed Environmental, Inc. (Environmental or Applicant), as the new emergency operator of Holly Hills Water System (Holly Hills or System) in Jackson County, North Carolina. The Order required the Public Staff to perform a final audit of the records of Wike Operations, Inc., to ensure an appropriate accounting transition from one emergency operator to another. The Order also approved the continuation of the rates previously approved for Wike Operations, subject to true-up upon subsequent review and approval of the actual cost of operating the water system. Holly Hills serves 28 customers.

On June 3, 2010, the Public Staff filed a Motion to Approve Interim Rate Increase and Assessment, Schedule Hearing on Rates and Assessment, and Require Customer Notice. In its Motion, the Public Staff requested that the Commission issue an order:(1) approving, on a provisional basis, an increase in monthly rates to ensure adequate monthly revenue to cover ongoing routine operating costs, (2) approving, on a provisional basis, a monthly assessment to recover $4,091 for past operating losses and past due Duke Energy bills, (3) deferring action on any assessments for additional improvements to the water system, (4) scheduling a hearing on the rates and assessments, and (5) requiring customer notice. The Public Staff requested that at the customer hearing the customers of Holly Hills be questioned regarding whether they were in favor of paying an additional assessment for the additional capital upgrades identified by the Public Staff.

By Order dated June 22, 2010, the Commission approved, on a provisional basis, the recommended rate increase and an assessment of $24.35 per month per customer, for a six-month period beginning July 2010, to pay a total of $4,091 owed by Holly Hills to Environmental and Duke Energy. The Order also scheduled a customer hearing, and required customer notice. The Commission also provided in its Order that it would seek input from the customers of Holly Hills regarding whether additional expenditures for improvements to the filter system should be made prior to the probable transfer of service to Tuckaseigee Water & Sewer Authority (TWSA) by the end of 2010. The Applicant filed a Certificate of Service on July 21, 2010.

The hearing was held as scheduled on Tuesday, August 3, 2010, in Sylva, North Carolina. Nine customers testified at the hearing: Kyline Robinson, Elizabeth Hoyle, Carol LeTorre, Theresa Brown, Frank Lockwood, Susan Roper, Thomas Frazier, Vicky Frazier, and Charles Moore. The Public Staff presented the testimony of Mr. Jerry Tweed, engineer with the Public Staff Water Division. The Applicant presented the testimony of Mr. Mark Teague, emergency operator for Environmental, Inc.

At the conclusion of the hearing, Mark Teague, on behalf of Environmental, took the witness stand and resigned as Emergency Operator.

On September 29, 2010, the Public Staff filed with the Commission an email dated August 5, 2010, from Environmental stating that Environmental would continue as emergency operator of the System. The Public Staff also filed on this date an email, dated September 29, 2010, from Environmental stating that it wanted to postpone its request for another assessment for additional improvements, as many customers had voiced their discontent with the current assessment.

FINDINGS OF FACT

1. On November 23, 2009, the Commission approved the appointment of Environmental as emergency operator of the Holly Hills Water System in Jackson County, North Carolina.

2. The Applicant was authorized by the Commission to increase the rates for water service from $20.00 for zero usage to $30.00, and to increase the water usage charge per 1,000 gallons from $2.75 to $4.39, subject to refund after notice and hearing.

3. The Applicant was authorized to assess each of its 28 customers a monthly assessment of $24.35 for six months, subject to refund after notice and hearing.

4. The increased rates, granted on a provisional basis, for service in Holly Hills are just and reasonable, and should be approved.

5. The surcharge imposed on Holly Hills customers on a provisional basis for the reimbursement of expenses owed to the Applicant and Duke Energy is just and reasonable and should be approved.

6. There are other capital upgrades that need to be done to ensure the proper ongoing operation of the System.

7. The quality of the water in Holly Hills is poor.

8. The customers are dissatisfied with the water quality of the System.

9. TWSA has plans to extend water service to Holly Hills in the near future, but the exact date is uncertain.

10. Improvement to the System's iron filter is needed, and an additional assessment should be approved when the Applicant requests the assessment and provides sufficient documentation.

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

The evidence for these findings of fact is found in the filings and record of this docket and is uncontested.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4 - 5

The evidence for these findings of fact is contained in the filing of the Applicant and the Public Staff, and in the testimony of Public Staff witness Jerry Tweed.

Public Staff witness Jerry Tweed testified that he and members of the Public Staff's Accounting Division had reviewed all the records of the previous emergency operator of the System, and based upon their review, recommended the rate increase to cover ongoing monthly operating costs for the System. Mr. Tweed also testified that, based on its review of financial records, the Public Staff recommended the six-month $24.35 per month assessment to pay past-due electric bills owed to Duke Power, and to reimburse Environmental for the $2,077 it incurred in making required repairs when it first took over the System.

Mr. Tweed explained why there was a past due electric bill of $2,014 owed to Duke Energy by the previous emergency operator, Wike Operations, and was not incurred while Environmental was operating the system. As stated by witness Tweed, Holly Hills had two separate power bill accounts, one for the main well and one for a small booster pump station. When Duke Energy transitioned from one company to another, it lost track of the Holly Hills account for the main well and only billed Wike Operations for the booster pump station, such that Duke failed to bill Wike Operations for approximately 18 months for the main well. He explained that Duke did not catch its mistake until just prior to Wike Operations ceasing to serve as emergency operator. Additionally, Mr. Tweed stated that the Public Staff had spent much time negotiating with Duke Energy, and had actually gotten the bill reduced to $2,014.

Witness Tweed testified that Environmental incurred $2,077 in operating losses, which included the cost of replacing a booster pump. Going forward, Mr. Tweed stated that the rates charged would cover the cost of running the System, with the exception of replacing the berm and repairing the filter.

Mr. Mark Teague of Environmental Inc., and emergency operator for the System, testified that when he started serving the system, there was no operator available, and there was a malfunctioning booster pump, which was not supplying water to several homes in the Holly Hills subdivision. He stated that the rates approved will meet the normal operations of the System, and the assessment will pay for all or a part of the out-of-pocket payments already made for repairs to the System.

There was no public testimony in opposition to the increased rates or the surcharge. However, two customers questioned the right of Duke Energy to charge the System for past due bills when they had failed to charge for 18 months.

Based upon the testimony presented at the hearing, the Hearing Examiner concludes that the increase in rates is reasonable and is hereby approved, and the surcharge in the amount of $24.35 for six months is justified and reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 6 - 10

The evidence for these findings of fact is found in the filings in the testimony of Public Staff witness Tweed and Mr. Mark Teague, and customer testimony.

Public Staff witness Tweed testified that the Public Staff discovered that the System was in need of other capital upgrades to ensure the proper ongoing operation of the System, such as the need for improvements to the berm and filter system; and an additional $3,000 to $4,000 would be needed to do those repairs to the iron filter.

Additionally, Mr. Tweed stated that the repairs to the iron filter would give customers better quality of water than what they are receiving. He also stated that the Public Staff, however, wanted to hear from the customers regarding whether they wanted to invest that much money in a system that was probably going to be taken over by TWSA in the near future. Mr. Tweed estimated that the customers would need to be assessed a one-time assessment of $100 to $150 for the additional improvements.

Mr. Teague testified that he estimated that approximately $3,000 to $4,000 is needed to repair the iron filter that is not operable. He explained that the berm, which is the media for the filter needs to be changed. Additionally, he stated that he is doing as much as possible to alleviate the water quality problem by flushing the system. However, flushing often makes the water quality worse immediately after flushing.

Nine customers testified at the hearing. Most of the public witnesses testified regarding the poor quality of the water, and two witnesses brought samples of dirty water filters and dirty clothes damaged by the water. Other Holly Hills customers testified to dirty brown bath water and dirty grimy water in their commodes. Many of the witnesses testified to the numerous times they had to replace water filters and the expense of the filters.

Regarding whether they would support an additional assessment to repair the System's water filter, of the nine customers who testified at hearing, four customers were against an assessment, three customers were in favor of an assessment, and two customers were undecided, depending upon whether or not the water quality continued to get worse.

One customer witness who was in favor of an assessment, Ms. Carol LeTorre, testified that she had heard that TWSA had been awarded a grant to provide new water service to Holly Hills; however, she had also heard that service might be contingent on another factor happening. Therefore, Ms LeTorre acknowledged uncertainty on when or whether TWSA would provide service and was in favor of a surcharge to improve water quality, since the quality was so bad. Another witness also expressed concern that it could take more time than anticipated for the TWSA connection, and therefore was in favor of the additional surcharge to cover improvements.

In light of the testimony of the Public Staff, Mr. Mark Teague and the customer testimony, the Hearing Examiner finds and concludes the following: (1) the water quality in Holly Hills is poor and improvements need to be made to improve water quality, (2) it is unclear when TWSA will begin providing service to Holly Hills, and (3) an additional assessment will need to be imposed if the emergency operator makes necessary repairs to improve the water quality in Holly Hills.

Although the Public Staff provided information in its June 3, 2010, Motion that TWSA anticipated providing service to Holly Hills by the end of 2010, there was no testimony at hearing regarding when TWSA would definitely be paralleling the System and providing service. There was also customer testimony questioning when and whether TWSA would be providing service to Holly Hills in the near future. Notwithstanding the testimony of four customers who opposed the additional assessments for repair or replacement of the iron filter, the Hearing Examiner finds that the testimony concerning the extremely poor quality of the water warrants repair of the iron filter. It is unclear when TWSA will provide service to Holly Hills and customers should not have to endure extremely poor quality water or incur the additional expense of buying water filters, purchasing water or ruining clothing or appliances for six months or, most likely, longer, when there is a possible solution. As testified by Mr. Teague, there is little that he can do to improve water quality unless the filter is repaired.

In light of the foregoing, the Hearing Examiner finds and concludes that there is a dire need for improvement to the Holly Hills system, and, at some point, the customers should be assessed for repair or replacement of the iron filter, or for any other essential upgrades to the System. However, since, there were no specific estimates or invoices provided regarding the cost of repairing or replacing the iron filter or for making additional necessary repairs, the Applicant should provide to the Public Staff estimates and/or receipts for the repairs or purchases when they are completed. When the Applicant provides estimates or receipts supporting its request for the additional one-time assessment, the Hearing Examiner will rule on the exact amount of assessment, if any, to assess the Holly Hills customers. Moreover, in light of the

Applicant's recent filing requesting that its request for additional assessment be postponed, the Hearing Examiner finds further justification for finding that an order allowing an additional assessment should not be issued at this time.

IT IS, THEREFORE, ORDERED as follows:

1. That the rate increase and six-month surcharge previously approved on a provisional basis are hereby approved.

2. Environmental shall provide the Public Staff with verified estimates and/or invoices for payments made for repair or replacement of the iron filter, or for any other necessary repairs to the System when they are made.

3. That the Commission shall consider the issue of whether to further assess the Holly Hills customers after Environmental has provided the requisite estimates or receipts for repairs.

4. That a copy of this Order shall be mailed with sufficient postage or hand delivered by Environmental, Inc., to all customers in the Holly Hills Subdivision no later than 10 days after the date of this Order; and that Environmental, Inc., submit to the Commission the attached Certificate of Service properly signed and notarized not later than 20 days after the date of this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 6th day of October, 2010

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

rb100610.01

WATER AND SEWER – EMERGENCY OPERATOR

CERTIFICATE OF SERVICE

I, ______________________________________, mailed with sufficient postage or hand delivered to all affected customers the attached Notice to Customers issued by the North Carolina Utilities Commission in Docket No. W-1054, Sub 12, and the Notice was mailed or hand delivered by the date specified in the Order.

This the _____ day of __________________, 2010.

By: ________________________________
Signature

____
Name of Utility Company

The above named Applicant, ____________________________, personally appeared before me this day and, being first duly sworn, says that the required Notice to Customers was mailed or hand delivered to all affected customers, as required by the Commission Order dated ________________ in Docket No. W-1054, Sub 12.

Witness my hand and notarial seal, this the ____ day of _____________, 2010.

____
Notary Public

____
Address

(SEAL) My Commission Expires: ________________________________
Date

DOCKET NO. W-1273, SUB 2

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Appointment of Brunswick County Utilities as Emergency Operator for the Sewer Utility System in Brick Landing Plantation Subdivision in Brunswick County, North Carolina	)))))	ORDER APPOINTING EMERGENCY OPERATOR, DECLARING BOND FORFEITED, AUTHORIZING NEW RATES, AND REQUIRING CUSTOMER NOTICE

BY THE COMMISSION: On August 13, 2003, in Docket No. W-1273, Sub 0, CTC Brick Landing, LLC (CTC, Company), was granted temporary operating authority to provide sewer service in the Brick Landing Plantation Subdivision in Brunswick County, North Carolina. In accordance with that Order, a bond was posted in the amount of $50,000.

On February 25, 2009, CTC filed an application with the Commission in Docket No. W-1237, Sub 1, for authority to transfer the sewer utility system to Brunswick County, which is exempt from Commission regulation. The County and CTC had entered into an agreement providing that upon the closing of the transaction between the parties, the County would take possession of and operate the sewer utility system until the system could be connected to the County sewer system. Under the agreement, CTC would finance the construction of a new force main and lift station to connect the collection system in Brick Landing Plantation to the County's regional system. Once that force main and lift station were constructed and on-line, the County would de-commission the treatment plant located in Brick Landing. In addition, CTC would pay the County an estimated $225,100 for improvements to the existing sewer collection system, lift stations and treatment plant. Under the agreement, all work associated with constructing the lift station and force main were to be completed by September 1, 2009. By Commission Order dated April 27, 2009, in Docket No. W-1237, Sub 1, the Commission approved a transfer of the sewer utility system serving Brick Landing Plantation Subdivision to Brunswick County at Brunswick County's then current rates. However, the closing and transfer has not occurred, and none of the construction or improvements to the sewer utility system has been performed.

On March 18, 2010, the Public Staff filed a verified Motion recommending that Brunswick County Utilities be appointed emergency operator of Brick Landing Subdivision's sewer system. The Public Staff stated that Brunswick County had agreed to serve as emergency operator and is capable of arranging for necessary repairs to this sewer system and is capable of providing adequate service, and that CTC has consented to that appointment. The Public Staff also recommended increasing the rates (from its current rate of $25.81 flat rate) to the level paid by Brunswick County customers, as provided in the Commission's Order of April 27, 2009, described above.

Based upon the foregoing and the record in this docket and in Docket No. W-1273, Sub 1, the Commission makes the following

WATER AND SEWER – EMERGENCY OPERATOR

FINDINGS OF FACT

1. By Order dated June 29, 2007, in Docket No. W-1273, Sub 0, CTC Brick Landing, LLC (CTC, Company), was granted temporary operating authority to provide sewer service in the Brick Landing Plantation Subdivision in Brunswick County, North Carolina. In accordance with that Order, a bond was posted in the amount of $50,000.

2. On February 25, 2009, CTC filed an application with the Commission in Docket No. W-1237, Sub 1, for authority to transfer the sewer utility system to Brunswick County, which is exempt from Commission regulation. The County and CTC had entered into an agreement providing that upon the closing of the transaction between the parties, the County would take possession of and operate the sewer utility system until the system could be connected to the County sewer system. Under the agreement, CTC would finance the construction of a new force main and lift station to connect the collection system in Brick Landing Plantation to the County's regional system. Once that force main and lift station were constructed and on-line, the County would de-commission the treatment plant located in Brick Landing. In addition, CTC would pay the County an estimated $225,100 for improvements to the existing sewer collection system, lift stations and treatment plant. Under the agreement, all work associated with constructing the lift station and force main were to be completed by September 1, 2009. By Commission Order dated April 27, 2009, in Docket No. W-1237, Sub 1, the Commission approved a transfer of the sewer utility system serving Brick Landing Plantation Subdivision to Brunswick County at Brunswick County's then current rates. However, the closing and transfer has not occurred, and none of the construction or improvements to the sewer utility system has been performed.

3. The Public Staff filed a verified Motion dated March 18, 2010, in this docket and recommended that Brunswick County Utilities be appointed emergency operator of the sewer system. The Public Staff stated that Brunswick County Utilities has agreed to serve as emergency operator and that CTC has consented to the appointment of an emergency operator. The Public Staff also recommended approving Brunswick County's current rates and charges and declaring the bond posted by CTC to be forfeited.

4. There is imminent danger of losing sewer service due to the lack of a competent utility company and the lack of funds to pay current and outstanding bills, and to pay for upgrades to the system. Further, the Brunswick County Health Department has suspended the operational permit for the system, issued a notice of violation, and made a notification of safety hazard. All of the foregoing justifies the appointment of an emergency operator in accordance with G.S. 62-116(b).

5. Brunswick County Utilities has the ability to provide the emergency service to Brick Landing Plantation Subdivision, and the Public Staff states that it has agreed to serve as emergency operator for that Subdivision's sewer facility for up to three months in order to arrange for the most urgently needed repairs and to take remedial action to the extent that they can be funded with the bond funds and revenues collected from Brick Landing customers. A more expensive, long-term solution to the situation at Brick Landing is required, and Brunswick County's willingness to participate in bringing about that solution will depend upon the

cooperation of CTC and others during the time Brunswick County Utilities serves as emergency operator.

6. It is appropriate at this time to approve the same rates and charges as charged by Brunswick County to its other customers and to declare the bond posted by CTC to be forfeited.

7. CTC has filed $50,000 in bonds with the Commission pursuant to G.S. 62-110.3. Pursuant to this statute, these bonds are hereby declared forfeited. (According to the Public Staff, CTC has consented to the forfeiture of these bonds.) The proceeds of these bonds will be subject to distribution by the Commission in subsequent orders.

CONCLUSIONS

Based upon the foregoing and the filings made in this Docket and in Docket No. W-1273, Sub 1, the Commission is of the opinion that an emergency exists with respect to the sewer utility system serving Brick Landing Plantation Subdivision; that there is an imminent danger of loss of adequate sewer utility service, constituting an emergency pursuant to G.S. 62-116(b); that an emergency operator should be appointed; that the emergency operator should be allowed to charge the rates reflected in Appendix B attached hereto; and that customer notice should be given.

IT IS, THEREFORE, ORDERED as follows:

1. That Brunswick County Utilities, Post Office Box 249, Bolivia, North Carolina 28422, is hereby appointed as the emergency operator of the sewer utility system serving Brick Landing Plantation Subdivision in Brunswick County, North Carolina, for a period of three months from the date of this order or until Brunswick County Utilities notifies the Commission in writing that it no longer agrees to serve as emergency operator, whichever occurs first, subject to extension upon written notification by Brunswick County Utilities of its willingness to continue as the emergency operator for an additional period.

2. That the Notice to Customers, attached as Appendix A, be mailed with sufficient postage or hand delivered by Brunswick County Utilities to all customers in Brick Landing Plantation Subdivision no later than 15 days after the date of this Order; and that Brunswick County Utilities submit to the Commission the attached Certificate of Service properly signed and notarized not later than 30 days after the date of this Order.

3. That the Schedule of Rates, attached as Appendix B, is approved for sewer utility service provided by the emergency operator of the Brick Landing Plantation Subdivision sewer utility system.

4. That the following provisions are adopted by this Order:

a. That the emergency operator shall maintain full records of receipts and expenses and shall file with the Commission and Public Staff by the end of the subsequent month, a summary financial report on a quarterly basis.

b. That the emergency operator shall have charge of the daily operation of the sewer utility system in Brick Landing Plantation Subdivision, and the emergency operator's duties and responsibilities shall include, among others, the following:

(i) Regular inspections and testing of the sewer utility system;
(ii) Billing of all customers and collection of bills;
(iii) Routine and emergency maintenance and repair;
(iv) System renovations and additions necessary to maintain adequate sewer utility service;
(v) Quarterly accounting to the Utilities Commission and the Public Staff of all rates collected, expenses incurred, checks written, and all monies spent; and
(vi) Providing a telephone number to customers for routine and emergency calls and its mailing address.

c. That the emergency operator may contract with any person or corporation to carry out any of the duties necessary for operation and repair of the sewer utility system, but the emergency operator shall have the ultimate, sole responsibility to see that such duties are carried out.

d. That the emergency operator, in the performance of its duties, shall be free to seek assistance from customers of the sewer utility system, plumbers, engineers, attorneys, and such other persons as may be necessary for the performance of its duties and responsibilities.

e. That the emergency operator shall, when it becomes necessary in the performance of its duties, seek the assistance of the Division of Environmental Health, Division of Water Quality, the North Carolina Utilities Commission, and the Public Staff of the Utilities Commission, and the Brunswick County Health Department.

f. That the emergency operator shall collect from the customers of the sewer utility system such rates and assessments as may be approved by the North Carolina Utilities Commission and shall be fully authorized to bill and collect said rates and assessments and to disburse those funds as may be necessary to provide safe, reliable, and adequate sewer utility service to the customers. Any customer who fails to pay the bill(s) authorized by this paragraph shall be disconnected by the emergency operator as provided by the orders, rules, and regulations of the Utilities Commission.

g. That the emergency operator shall be entitled to all available records relating to the sewer utility system, and those records shall include, but not be limited to, a list of customer names, addresses, and billing records.

h. That the emergency operator shall keep records of all monies collected through the rates and assessments, and all monies expended in the operation of the sewer utility system. In order to protect the customers' interests in the sewer utility system, the emergency operator is required to keep a separate record of all monies and assessments collected from customers and expended on improving and upgrading the sewer utility system, including, but not limited to, construction or replacement of the sewer distribution/collection system, metering devices, or other improvements and the cost of labor associated with those improvements whether performed by the emergency operator or a contractor hired by the emergency operator.

i. That the emergency operator shall pay only those liabilities incurred by the emergency operator on and after the date of the appointment of the emergency operator. Those liabilities shall be defined as the liabilities arising from the emergency operator's operation of the Brick Landing Plantation Subdivision sewer utility system pursuant to Commission Order. The disbursements by the emergency operator shall be made from the separate account set up by the emergency operator and the emergency operator shall account for any funds advanced by it for the operations.

j. That the appointment of the emergency operator shall continue until terminated by an Order of the Commission finding that the emergency has ended and that the emergency operator is no longer required pursuant to G.S. 62-116(b) to provide sewer public utility service to the customers of the Brick Landing Plantation Subdivision.

k. That the emergency operator may petition the Commission at any time to be discharged as the emergency operator herein; and the emergency operator, prior to its discharge, shall provide an acceptable accounting to the Utilities Commission of all monies collected and disbursed during its tenure as emergency operator, as well as the amounts due and owing the emergency operator at the time of its discharge for its services performed as emergency operator. The emergency operator filing a petition for discharge shall also mail a copy of said petition to the Brunswick County Health Department, the Division of Environmental Health and the Division of Water Quality.

5. That the bonds posted by CTC Brick Landing, LLC, pursuant to G.S. 62-110.3 are hereby forfeited; and the proceeds of the bonds shall be distributed by subsequent Orders of the Commission.

6. That this docket shall remain open for further motions, reports, etc., of the parties, the emergency operator, the Brunswick County Health Department, the Division of Environmental Health, the Division of Water Quality, and for further Orders of the Commission.

7. If requested by the emergency operator, a representative of CTC shall meet with the emergency operator at a mutually acceptable time and place in order to review the system and simplify the transfer of duties.

8. That the following items of information be made available to the emergency operator by CTC:

a. Customer information for each residence connected to the system, containing at a minimum, customer name, service address, billing address, contact phone numbers (home and work), and billing records.

b. Copy of latest electrical power bill for any electric service associated with operation of the system (needed for transfer of service).

c. Copy of system plans and specifications with any noted discoveries or changes by current owner for the past 12 months.

d. Copies of all monitoring reports and evaluation completed by current operator for the past 12 months.

e. Copies of the latest 12 months of purchased sewer bills, which are needed for transfer of service and evaluation of consumption.

9. That the emergency operator shall keep a separate checking account for emergency operations at Brick Landing Plantation Subdivision sewer utility system.

10. The Chief Clerk of the Commission shall mail copies of this Order to:

a. CTC Brick Landing, LLC, 8450 Falls of Neuse Road, Suite 202, Raleigh, North Carolina 27615

b. Brunswick County Utilities, Post Office Box 249, Bolivia, North Carolina 28422

c. Division of Environmental Health, Division of Water Quality, 512 N. Salisbury Street, Raleigh, North Carolina 27604

ISSUED BY ORDER OF THE COMMISSION.
This the 24th day of March, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

rb032310.12

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

APPENDIX A
PAGE 1 OF 2

DOCKET NO. W-1273, SUB 2

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Appointment of Brunswick County Utilities as	)	
Emergency Operator for the Sewer Utility	)	NOTICE TO CUSTOMERS
System in Brick Landing Plantation Subdivision	)	
in Brunswick County, North Carolina	)	

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission has concluded that there is an imminent danger of loss of adequate sewer utility service in Brick Landing Plantation Subdivision in Brunswick County, North Carolina, constituting an emergency pursuant to G.S. 62-116(b). The Commission has therefore appointed an emergency operator for the sewer utility system serving Brick Landing. The contact information for the emergency operator is as follows:

Brunswick County Utilities, Post Office Box 249, Bolivia, North Carolina 28422. Its phone number is (910) 253-2657.

CTC Brick Landing, LLC, is the current owner of the Brick Landing Plantation Subdivision sewer facility.

The sewer utility service rates for Brick Landing Plantation Subdivision at this time will be Brunswick County's current rates and charges, which are as follows:

Base charge, including first 3,000 gallons usage	$39.00
Usage charge, per 1,000 gallons for all over 3,000 gallons	$6.50
Average bill based on 6,000 gallons per month	$58.50

The Public Staff is authorized by statute to represent consumers in proceedings before the Commission. Written statements to the Public Staff concerning the appointment of the emergency operator should be addressed to Mr. Robert Gruber, Executive Director, Public Staff, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326. Written statements can also be faxed to (919) 715-6704 or e-mailed to david.furr@psncuc.nc.gov.

APPENDIX A
PAGE 2 OF 2

The Attorney General is also authorized by statute to represent consumers in proceedings before the Commission. Statements to the Attorney General should be addressed to The Honorable Roy Cooper, Attorney General, 9001 Mail Service Center, Raleigh, North Carolina 27699-9001.

This the 24th day of March, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

APPENDIX B

SCHEDULE OF RATES

for

CTC BRICK LANDING, LLC
(Brunswick County Utilities, Emergency Operator)

for providing sewer utility service in

BRICK LANDING PLANTATION SUBDIVISION

Brunswick County, North Carolina

Monthly Residential Sewer Rate

Base charge, including first 3, 000 gallons usage	\$39.00
Usage charge, per 1,000 gallons for all over 3,000 gallons	\$ 6.50

(These are the same rates and charges as approved by Brunswick County for its other customers.)

Tap-On Fee: \$1,100.00
Per single family equivalent

Reconnection Charge:

If sewer utility service discontinued by utility for good cause:	\$15.00
If sewer utility service discontinued at customer request:	\$15.00

WATER AND SEWER – EMERGENCY OPERATOR

Bills Due:	On billing date
Bills Past Due:	15 days after billing date
Billing Frequency:	Shall be monthly for service in arrears
Finance Charges for Late Payment:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-1273, Sub 2, on this the 24th day of March, 2010.

CERTIFICATE OF SERVICE

I, ____, mailed with sufficient postage or hand delivered to all affected customers the attached Notice to Customers issued by the North Carolina Utilities Commission in Docket No. W-1273, Sub 2, and the Notice was mailed or hand delivered by the date specified in the Order.

This the _____ day of ___________________, 2010.

By: ________________________________
Signature

____
Name of Utility Company

The above named Applicant, ____________________________, personally appeared before me this day and, being first duly sworn, says that the required Notice to Customers was mailed or hand delivered to all affected customers, as required by the Commission Order dated _________________ in Docket No. W-1273, Sub 2.

Witness my hand and notarial seal, this the ____ day of _____________, 2010.

____
Notary Public

____
Address

(SEAL) My Commission Expires: ________________________________
Date

WATER AND SEWER – RATE INCREASE

DOCKET NO. W-1013, SUB 9

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Carolina Trace Utilities, Inc., 2335 Sanders Road, Northbrook, Illinois 60062, for Authority to Increase Rates for Water and Sewer Utility Service in the Carolina Trace Development in Lee County, North Carolina	)))))	ORDER GRANTING PARTIAL RATE INCREASE AND REQUIRING CUSTOMER NOTICE

HEARD IN: Sanford Municipal Building, Council Chambers, 225 E. Weatherspoon Street, Sanford, North Carolina on Tuesday, July 20, 2010, at 10:00 a.m.

Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina on Thursday, August 26, 2010 at 9:30 a.m.

BEFORE: Commissioner Bryan E. Beatty, Presiding; Commissioner Lorinzo L. Joyner; and Commissioner Lucy T. Allen

APPEARANCES:

For Carolina Trace Utilities, Inc.:

Christopher J. Ayers, Poyner Spruill, LLP, Post Office Box 1801, Raleigh, North Carolina 27602-1801

For the Using and Consuming Public:

Tab C. Hunter, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: On March 1, 2010, Carolina Trace Utilities, Inc. (Applicant, Carolina Trace, or Company), filed a letter notifying the Commission of its intent to file a general rate case as required by Commission Rule R1-17(a).

On March 31, 2010, Carolina Trace filed an application with the Commission seeking authority to increase its rates for water and sewer utility service in the Carolina Trace Development in Lee County, North Carolina. On April 1, 2010, the Applicant amended its application by filing replacement pages for Exhibit B.

The Applicant serves approximately 1,523 water customers and 1,493 sewer customers. The present rates for water and sewer utility service have been in effect since December 2008.[1]

[1] In Docket No. W-1013, Sub 7, an Order Granting Partial Rate Increase and Requiring Customer Notice was issued on December 19, 2008.

WATER AND SEWER – RATE INCREASE

By Order dated April 30, 2010, the Commission declared the above-captioned proceeding to be a general rate case pursuant to G.S. 62-137; suspended the proposed rates for a period of up to 270 days pending further investigation and hearing; and scheduled this matter for hearing in Sanford and Raleigh, North Carolina. The Applicant was required to provide customer notice of the hearings and the proposed rate increase to all customers.

On May 18, 2010, the Applicant filed its Certificate of Service indicating that notice was provided as required by the April 30, 2010 Order.

The North Carolina Utilities Commission Public Staff (Public Staff) received protests from 31 customers. The customer protests raised various concerns such as: the magnitude and frequency of the proposed rate increases; the matter that Carolina Trace has not negotiated with the City of Sanford for a lower wholesale purchased water rate; the calculation of the sewer bill based upon water usage; the numerous and lengthy outages that have occurred; the problems with discolored water and staining of bathroom fixtures; the insufficiency of system maintenance and repair; the incompleteness of the mapping of the sewer system; the lack of appropriate cut-off notice being provided prior to disconnection; the insufficiency of the time period allowed to pay the monthly bill which sometimes results in disconnections and/or late payments; and quality of customer service concerns.

On July 12, 2010, the Applicant prefiled the testimony of Brian W. Shrake, Senior Regulatory Accountant, Utilities, Inc.

On July 16, 2010, the Applicant filed revised Schedules A, B, and C to replace the schedules previously filed with its application.

On July 19, 2010, Carolina Trace filed a revised proposed schedule of rates to add a proposed charge for the installation of an irrigation meter. The Company requested that such proposed charge should be the actual cost of the installation.

On July 20, 2010, a public hearing for the purpose of receiving customer testimony was held in the Sanford Municipal Building, Council Chambers, 223 E. Weatherspoon Street, Sanford, North Carolina as scheduled. A total of 42 customers registered at the public hearing to present testimony; 25 of those actually testified; and 18 of the customers who testified presented letters and/or other information to be marked and treated as exhibit attachments.

Also on July 20, 2010, Carolina Trace and the Public Staff filed a Partial Settlement Agreement that was entered on July 19, 2010, which stipulated to the appropriate capital structure and cost rates for the components of the capital structure and return on rate base for the present proceeding.

On August 5, 2010, the Public Staff filed a motion for an extension of time to file testimony, which was granted on August 6, 2010.

On August 12, 2010, the Public Staff filed a second motion for an extension of time to file testimony. In support of its request, the Public Staff stated that the parties had reached agreement on all outstanding issues in the case but additional time was needed to memorialize their agreement and for the Public Staff to file supporting testimony. On August 13, 2010, the Commission issued an Order Granting Extension of Time.

On August 19, 2010, the Public Staff filed a Stipulation between Carolina Trace and the Public Staff (the Stipulating Parties), resolving all outstanding issues between them in this proceeding. Attached to the Stipulation was Stipulation Exhibit I summarizing the operating revenues, operating revenue deductions, rate base, and rate of return that the Applicant and the Public Staff agreed are appropriate for use in this proceeding. In addition, attached to the Stipulation was Exhibit II which is the Schedule of Rates showing the rates and charges intended to produce the agreed-upon revenue requirements for Carolina Trace's water and sewer operations. Also on August 19, 2010, the Public Staff prefiled the testimony and exhibits of Katherine A. Fernald, Supervisor, Water Section, Accounting Division, and O. Bruce Vaughn, Utilities Engineer, Water Division, in support of the Stipulation.

On August 20, 2010, the Public Staff filed a motion to excuse the witnesses for the Public Staff and the Applicant from the hearing.

On August 23, 2010, the Applicant filed a report addressing the service-related complaints expressed at the public hearing held in Sanford, North Carolina, on July 20, 2010.

On August 24, 2010, the Commission issued its Order excusing the Applicant's accounting witness from the evidentiary hearing, but denying the request to excuse the Public Staff's witnesses. The Commission also ordered the Applicant to present a witness to testify regarding operational and service-related issues.

On August 26, 2010, the evidentiary hearing was held in Raleigh, North Carolina, as scheduled. Three customers presented testimony at this hearing. The testimony of Carolina Trace witness Shrake was copied into the record as if given verbatim orally from the witness stand and was admitted into evidence by Stipulation and pursuant to the Commission ruling. The Public Staff presented the testimony of Katherine A. Fernald and O. Bruce Vaughn. Martin Lashua, Regional Director, testified on behalf of the Applicant.

On September 10, 2010, Carolina Trace filed four late-filed exhibits per the Commission's oral order from the bench at the August 26, 2010 hearing.

On October 20, 2010, Carolina Trace and the Public Staff filed a Joint Proposed Order.

Based on the application, the Partial Settlement Agreement, the Stipulation, the evidence adduced at the hearing, and the entire record in this proceeding, the Commission is of the opinion that the provisions of the Stipulation are just and reasonable. Accordingly, the Commission makes the following

FINDINGS OF FACT

1. Carolina Trace is a corporation duly organized under the law of and is authorized to do business in the State of North Carolina. Carolina Trace is a franchised public utility providing water and sewer utility service in the Carolina Trace Development in Lee County, North Carolina. Carolina Trace is a wholly owned subsidiary of Utilities, Inc.

WATER AND SEWER – RATE INCREASE

2. Carolina Trace is properly before the Commission, pursuant to Chapter 62 of the North Carolina General Statutes, for a determination of the justness and reasonableness of its proposed rates for its water and sewer utility operations.

3. Carolina Trace provides utility service to approximately 1,523 water customers and 1,493 sewer customers.

4. The test period appropriate for use in this proceeding is the 12-month period ended September 30, 2009.

5. The present water and sewer utility rates have been in effect since December 2008.

6. Thirty-one customer position statements were filed with the Commission, primarily to protest the magnitude of the proposed rate increase. At the public hearing on July 20, 2010, 25 public witnesses testified in this proceeding regarding various issues such as: (1) the magnitude of the proposed rate increase for water and sewer utility service; (2) the rate structure for water and sewer utility service; (3) issues regarding purchased water from the City of Sanford; (4) system operations and maintenance/repair; (5) water quality concerns; and (6) billing and customer service. Three public witnesses[1] testified at the evidentiary hearing held on August 26, 2010, in Raleigh, North Carolina.

7. Carolina Trace filed a report with the Commission on August 23, 2010, addressing the service-related concerns expressed by the public witnesses who testified at the customer hearing held in Sanford, North Carolina. Such report described each of the witnesses' specific service-related concern(s), the Applicant's response, and how each concern was addressed, if applicable.

8. The quality of service provided by Carolina Trace is adequate.

9. Carolina Trace's present and proposed water and sewer utility service rates are as follows:

Monthly Metered Water Utility Service:	Present Rates	Proposed Rates
Base charge, zero usage	$ 13.54 minimum	$ 14.89 minimum
Usage charge, per 1,000 gallons	$ 4.93	$ 5.42
Monthly Metered Sewer Utility Service:	**Present Rates**	**Proposed Rates**
Base charge, zero usage	$ 32.07 minimum	$ 40.15 minimum
Usage charge, per 1,000 gallons	$ 7.59	$ 9.50

10. Carolina Trace requested an increase in its water and sewer rates that would produce additional revenues of $54,840 for water operations and $252,225 for sewer operations.

[1] At the August 26, 2010 hearing in Raleigh, North Carolina, public witnesses Vincent Roy and Mike McDonald supplemented their testimony previously provided at the public hearing held in Sanford, North Carolina.

11. The Applicant's original cost rate base at September 30, 2009, for use in this proceeding after agreed-upon adjustments, is $650,398 for water operations and $4,628,756 for sewer operations.

12. Carolina Trace had water plant in service of $1,327,649 and sewer plant in service of $6,233,686 at the end of the test year, after agreed-upon adjustments.

13. The accumulated depreciation at the end of the test year, after agreed-upon adjustments, was $327,322 for water operations and $906,222 for sewer operations.

14. The contributions in aid of construction (CIAC), net of amortization, at the end of the test year, after agreed-upon adjustments, was $404,299 for water operations and $411,580 for sewer operations.

15. Carolina Trace is entitled to total rate case costs of $90,156, consisting of $10,128 in legal fees, $1,466 in costs related to customer notices, $1,000 in travel costs, $27,019 in personnel costs, $30 in miscellaneous costs, and $50,513 in unamortized rate case costs from the prior rate case proceeding, Docket No. W-1013, Sub 7. These total rate case costs should be amortized over a three-year period, resulting in an annual level of rate case expense of $30,052.

16. Carolina Trace's total operating revenue deductions under present rates are $526,746 for water operations and $729,388 for sewer operations.

17. It is reasonable and appropriate to calculate: regulatory fees using the statutory rate of 0.12%; gross receipts taxes using the statutory rates of 4% for water operations and 6% for sewer operations; and state and federal income taxes using the corporate rates of 6.9% for state income taxes and 34% for federal income taxes.

18. Carolina Trace's present rates generate total operating revenues of $555,829 for water operations and $1,009,933 for sewer operations.

19. The appropriate rate of return components to be used in this proceeding are 53% long-term debt with an embedded cost of debt of 6.60% and a common equity ratio of 47% with a return on common equity of 10.25%, resulting in an overall weighted return on rate base of 8.32%, as stipulated.

20. It is appropriate to determine the revenue requirement for Carolina Trace using the rate base method as allowed by G.S. 62-133.

21. Carolina Trace is entitled to changes in rates and charges that will produce total annual operating revenues of $597,945 for water operations and $1,190,843 for sewer operations, as stipulated.

22. The stipulated rates, as provided in Stipulation Exhibit II attached to the Stipulation, will produce additional revenues of $42,116 for water operations and $180,910 for sewer operations.

WATER AND SEWER – RATE INCREASE

23. Carolina Trace's total operating revenue deductions under the stipulated rates, including gross receipts taxes, regulatory fees, and income taxes are $543,861 for water operations and $805,939 for sewer operations.

24. The water and sewer utility service rates agreed to by the Stipulating Parties are as follows:

Monthly Metered Water Utility Service:	
Base charge, zero usage	$ 14.65 minimum
Usage charge, per 1,000 gallons	$ 5.28
Monthly Metered Sewer Utility Service: 1/, 2/	
Base charge, zero usage	$ 37.86 minimum
Usage charge, per 1,000 gallons	$ 8.96

1/ Residential sewer usage bills are based on water usage and are limited to payment for 10,000 gallons per month. Under this limit, residential usage charges may not exceed $89.60 (for 10,000 gallons), with total sewer bill not to exceed $127.46.

2/ Commercial sewer usage bills are based on total metered water usage, i.e., usage billing is not limited by a maximum volume.

25. It is appropriate to make the following amendments to the Applicant's current Schedule of Rates as requested by Carolina Trace in its application, as stipulated:

a. Add an irrigation meter installation charge equal to the actual cost of the installation.

b. Reinsert the following reconnection charge condition, which was inadvertently omitted from the Schedule of Rates approved in Docket No. W-1013, Sub 7: "Customers who ask to be reconnected within 9 months of disconnection will be billed for the approved monthly water and sewer base charges for each month they were disconnected."

c. Increase the returned check charge from $10.00 to $20.00.

26. The rates and charges agreed to by Carolina Trace and the Public Staff, as provided in Stipulation Exhibit II and included in Appendix A, attached hereto, are just and reasonable and should be approved.

27. Carolina Trace should update the Public Staff on a monthly basis regarding the status of negotiations with the City of Sanford for a lower purchased water rate beginning August 31, 2010, as stipulated. The monthly update should be filed with the Commission in Docket No. W-1013, Sub 9.

28. Carolina Trace should provide notice on its monthly bills advising that customers may contact the Company to discontinue water utility service during an extended absence from their residence, as stipulated. The notice should also advise customers that they are responsible for reconnection charges during their absence and that their liability for base charges will depend upon the duration of the period of discontinued use as described in the Schedule of Rates for this

docket, as stipulated. Customers should only be assessed the base charge as described on the Schedule of Rates but should not be billed for water and/or sewer usage charges during the discontinued-use time period, as stipulated.

29. Carolina Trace should periodically provide employee training on its customer service policies and response procedures, as stipulated.

30. The Applicant and the Public Staff have agreed to waive their respective right of appeal from a final Order of the Commission incorporating the matters agreed upon in the Stipulation.

31. The Stipulation provides that Carolina Trace and the Public Staff have agreed that none of the positions, treatments, figures, or other matters reflected in said Stipulation should have any precedential value, nor should they otherwise be used in any subsequent proceedings before this Commission or any other regulatory body as proof of the matter in issue.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1 THROUGH 5

The evidence for these findings of facts is contained in the application; in the Commission records; in the testimony of Carolina Trace witness Shrake; in the Stipulation; and in the testimony and exhibits of Public Staff witness Vaughan. These findings are primarily jurisdictional and informational and are uncontested.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 6 THROUGH 8

The evidence for these findings of fact is contained in the Commission's records; in the testimony of the public witnesses; in the testimony of Public Staff witness Vaughan; in the testimony of Carolina Trace witness Lashua; in Carolina Trace's Customer Complaint Follow-up Report filed on August 23, 2010; and in Carolina Trace's Response to Commission's Questions from Evidentiary Hearing filed on September 10, 2010 (Response to Commission's Questions).

Witness Vaughan testified that the Public Staff received 31 letters in this docket from customers of Carolina Trace. Witness Vaughan further testified that of the 42 witnesses who registered at the customer hearing in Sanford on July 20, 2010, 18 testified and presented letters and/or other information to be marked and treated as exhibit attachments and eight[1] additional customers testified but did not submit any documentation to the Commission. Witness Vaughan stated that the major customer issues in this proceeding included the following: (1) the magnitude of the proposed rate increase for water and sewer utility service; (2) the rate structure for water and sewer utility service; (3) infrastructure, system operations, maintenance/repair; and (4) billing and customer service.

Pursuant to the Stipulation entered and filed on August 19, 2010, the Applicant agreed to file a report on all service-related issues in this proceeding no later than August 23, 2010. On August 23, 2010, Carolina Trace filed a report addressing the service-related complaints

[1] Public witnesses Yvonne George and Ken George testified separately but both provided 6034 Masters Circle, Sanford, North Carolina as their place of residence; consequently, the Commission considers the total number of customers that testified at the July 20, 2010 hearing to be 25 rather than 26.

expressed at the public hearing. In such report, Carolina Trace described each of the witnesses' specific service-related concern(s), the Company's response, and how each concern was addressed, if applicable. The Company stated that it had dispatched field personnel to visit with customers that raised water quality issues at the July 20, 2010 hearing and had conducted testing. Carolina Trace reported that water quality test results showed that pressure and quality were in acceptable ranges for all customers tested. In addition, the Company stated that it regretted any unacceptable experience(s) customers have had with Carolina Trace's customer service personnel.

In regard to the three witnesses that testified at the August 26, 2010 hearing in Raleigh, North Carolina, two of the witnesses, witness Vincent Roy and Mike McDonald supplemented their testimony previously provided at the July 20, 2010 customer hearing in Sanford, North Carolina. Public witness Roy expressed concerns regarding the number of monthly shutoffs for nonpayment and the amount of time allowed for customers to pay their monthly bills. Public witness McDonald expressed concerns regarding the bulk wholesale rate that Carolina Trace pays the City of Sanford for purchased water; whether the Company actively seeks to find lower prices on purchased items such as chemicals; and his belief that Carolina Trace is guaranteed a rate of return even if the Company operates inefficiently.

With respect to the condition of the Applicant's water and sewer systems, Public Staff witness Vaughan testified that he had reviewed the inspection and compliance records from the files of two divisions of the North Carolina Department of Environment and Natural Resources (DENR), specifically, the Public Water Supply Section (PWSS) of the Division of Environmental Health (DEH) and the Division of Water Quality (DWQ). Further, witness Vaughan explained that he and a Carolina Trace employee conducted an inspection of the water and wastewater systems on June 3, 2010, and he found no problems.

In regard to Carolina Trace's attempts to eliminate or reduce wastewater system deficiencies that have historically led to regulatory violations and increased expense, witness Vaughan testified that the Company has met several of its goals but still has some obstacles to overcome. Witness Vaughan summarized those goals as follows:

1. Inspect and clean a minimum of 10% of the wastewater collection system every year.

2. Map the wastewater collections system.

3. Eliminate inflow to the WWTP [wastewater treatment plant] and/or leakage from mains.

4. Reduce inflow and infiltration (I&I) into the WWTP of water that is not a wastewater byproduct of residential or commercial water usage, by locating and repairing infiltration sites.

Under cross-examination by the Commission, witness Lashua testified that the Company routinely cleans a minimum of 10% of the sewer system mains each year as required by state regulations. Further, witness Lashua explained that Carolina Trace hires contractors that utilize a device similar to a pressure washer to perform such cleaning.

In regard to mapping of the wastewater collections system, witness Lashua testified that the mapping was completed in late 2008 or early 2009. He stated that there may be a situation where a very small percentage of facilities may have been missed in the mapping project. Witness Lashua observed that a complete set of the maps is available for viewing by any interested party at the local Carolina Trace office.

With respect to eliminating inflow to the wastewater treatment plant and/or leakage from mains, Public Staff witness Vaughan testified that annual inspection of all mains is not required by DWQ; however, Carolina Trace does inspect the manholes associated with the gravity mains cleaning or high priority/heavy use mains. Public Staff witness Vaughan observed that the Company has found several previously unknown manhole locations as the result of its mapping efforts and by utilizing the information supplied by its customers.

Public Staff witness Vaughan testified that Carolina Trace continues to have a problem with inflow and infiltration into the wastewater treatment plant. Witness Vaughan stated that for the period May 2009 through April 2010, monthly WWTP flow was approximately 2.5 million gallons per month more than metered sewer usage (based on metered water, before any reduction for maximum sewer billing of 10,000 gallons per monthly bill).

Under cross-examination by the Commission, witness Lashua testified that since the last rate case proceeding the Company has completed several projects to reduce inflow and infiltration into the wastewater treatment plant. Specifically, witness Lashua noted that the Company had recently finished the installation of a new pump station and force main beside the lake and the Company had recently completed the replacement and rerouting of a main that was originally installed by the developer in a storm drain. However, witness Lashua observed that Carolina Trace continues to have a number of issues related to inflow and infiltration into the wastewater treatment plant that the Company is working to correct.

With respect to the customer concerns regarding the Company's disconnect policy, witness Lashua explained during cross-examination by the Commission that there are at least two occasions that the customer is notified that the bill has not been paid before the customer is disconnected for nonpayment. First, a letter is sent to the customer when the payment is not received by the due date. Such letter provides for an additional 10 days for the customer to make payment. Second, when the next monthly bill is processed, it contains language stating that the bill is delinquent. Consequently, witness Lashua opined that adequate notice is given prior to disconnection of service. Witness Lashua testified that the current 15 days past due date has been on the Company's tariff as long as he can remember.

In regard to a customer's assertion that the Company does not credit a customer's account until the check clears the bank, witness Lashua clarified, during cross-examination by the Commission, that the Company credits the customer's account when the payment is received rather than waiting until the check clears the bank.

The Commission has reviewed the testimony of the public witnesses; Carolina Trace's Customer Complaint Follow-up Report; the Company's Response to Commission's Questions; the testimony of the Company witness and the Public Staff witnesses provided at the August 26, 2010 evidentiary hearing; and Paragraph Nos. 19, 20, and 21 of the Stipulation and believes that the service-related concerns have been adequately addressed. In reaching such conclusion, the Commission has also considered the matters discussed hereinbelow in Evidence and Conclusions for Findings of Fact Nos. 9 through 18 and 20 through 26. Further, the Commission observes that Carolina Trace's 15-day period for payment of customer utility bills is consistent with Commission Rule R12-9(c).

EVIDENCE AND CONCLUSIONS FOR
FINDING OF FACT NOS. 9 THROUGH 18 AND 20 THROUGH 26

The evidence supporting these findings of fact is contained in the application; in the Commission's records; in the Stipulation; in the testimony and exhibits of Public Staff witnesses Fernald and Vaughan; in the testimony of Carolina Trace witness Lashua; and in the Company's Response to Commission's Questions.

As set forth in the provisions of the Stipulation entered and filed on August 19, 2010, Carolina Trace and the Public Staff agreed that the levels of rate base, revenues, and expenses as set forth in Stipulation Exhibit I, attached to said Stipulation, are the appropriate levels for use in this proceeding. Further, Public Staff witness Fernald filed testimony and exhibits on August 19, 2010, in support of the Stipulation. On that same date, Public Staff witness Vaughan filed testimony and exhibits with respect to the details of his investigation of the Applicant's request for a water and sewer utility service rate increase, including his recommendations regarding service revenues under present and proposed rates; purchased water expense; purchased sewer expense; chemicals expense; testing fees expense; sludge removal expense; rate design; and other tariff additions/amendments.

Regarding increases in operating expenses since the last rate case proceeding, Carolina Trace witness Lashua testified that Carolina Trace had placed a new sewer plant into service in 2008, which was included as pro forma plant in service in the Company's prior rate case proceeding. In its Response to Commission's Questions, the Company stated that said sewer plant addition has more than doubled the capacity of the facility from 0.325 million gallons per day (MGD) to 0.675 MGD. The Company explained that the current rate case proceeding is the first proceeding in which a full year of actual expenses related to such new sewer plant has been included in the test year. Consequently, the Company stated that there are now two wastewater treatment plants currently in operation which has resulted in a significant increase in the amount of operations and maintenance expense when compared to the previous rate case proceeding. The Company further explained that the new wastewater treatment plant contains larger and additional equipment and is more expensive to maintain and operate. The new sewer plant has its own blowers, pumps, and equipment that have substantially added to the electrical load of the facility; thereby significantly increasing the amount of sewer purchased power expense when compared to the previous rate case proceeding.

In addition, witness Lashua testified at the August 26, 2010 evidentiary hearing and the Company indicated in its Response to Commission's Questions that since the last rate case proceeding, Carolina Trace has incurred additional costs related to improvements and maintenance of its sewer collections system, including its efforts to reduce inflow and infiltration into the wastewater treatment plant.

Further, witness Lashua testified that, as determined by the corporate executive team located in Northbrook, Illinois, an average annual salary increase of 3% was given to employees in April 2010, which has been reflected in operating expenses in the present rate case proceeding.

In regard to the source of supply for providing water utility service, witness Vaughan testified that Carolina Trace purchases the majority of water used and/or consumed by the Company from the City of Sanford, through a master meter, and an eight-inch diameter water main connection. Witness Vaughan stated that during the test year, the Applicant purchased approximately 70% of the total volume of water available for Carolina Trace customers. Witness Vaughan explained that the balance (30%) of the water required by Carolina Trace customers is provided by the Company's community water system which consists of two wells, two well houses, a 150,000 gallon elevated storage tank, chemical feed equipment for chlorination and caustic soda addition, and distribution mains. Witness Vaughan opined that dual sources of water supply greatly reduce the possibility of an outage, and the need for an on-site emergency water source.

Further, witness Vaughan testified that Carolina Trace purchases water from the City of Sanford based on the City of Sanford's wholesale rates, which have not been revised for several years.[1] Witness Vaughan stated that he recommended approval of $161,551, as calculated on Vaughan Purchased Water Exhibit attached to his prefiled testimony, for purchased water expense based upon his review of annual billing data and monthly City of Sanford water billing statements obtained from the Company and rate information and billing summaries obtained from the City of Sanford's water department. Such level of purchased water expense includes an allowance of 12.5% for unaccounted for water, as stipulated.

On cross-examination by the Commission, witness Lashua testified that if Carolina Trace were to buy all of its water from the City of Sanford, as some customers have suggested in this present proceeding, it would present some challenges for the Company in that the Carolina Trace would be subject to one source of water which could have an impact on rates in the future without any checks or balances. Witness Lashua explained that with a supplemental source of water from the Company's wells, Carolina Trace does have some options available. Further, witness Lashua explained that in 2007 – 2008, when North Carolina experienced a significant drought situation, the State openly encouraged utilities to seek additional sources adjacent to their utilities to interconnect with and/or to develop new sources of water. Witness Lashua stated that having the wells in a useable state provides some beneficial options to the Carolina Trace community. Witness Lashua noted that if the two wells were shut off and not tested at all, there would be no cost in terms of testing fees or electrical expense; however, the wells would not be a source of water supply that could be immediately returned to service, if needed. Witness Lashua explained that the Company would have to work with the Public Water Supply Section to get the wells back operational, which could take anywhere from a minimum of two to four weeks depending upon the suitable level of potassium at that time.

[1] In its late-filed exhibits filed September 10, 2010, Carolina Trace provided a copy of a letter dated July 1, 2010, from Victor Czar, Public Works Director, City of Sanford, in which Mr. Czar stated that Sanford's records indicate that the same rate has been applied for Carolina Trace since at least 1996.

With respect to the wholesale rate the City of Sanford charges Carolina Trace, on cross-examination by the Commission, witness Lashua pointed out that negotiations with the City of Sanford are a little one-sided because the Company does not have a lot to negotiate with; that is, the Company is a buyer of a product from the City of Sanford and pays what the City of Sanford charges. However, witness Lashua stated that, as indicated in the Stipulation, the Company planned to begin negotiations with the City of Sanford as early as August 2010 and would begin reporting to the Public Staff at the end of August 2010 regarding the status of such negotiations.

In regard to the concerns expressed by the public witnesses that other utilities located outside the city limits of Sanford pay a lower wholesale purchased water rate than Carolina Trace pays, the Company stated in its Response to Commission's Questions that Carolina Trace had contacted the City of Sanford regarding obtaining a copy of its out-of-town bulk water rate policy and was informed that the City of Sanford does not have a written policy with respect to its out-of-town bulk water rates and that such rates are set on a contractual basis.

Lastly, witness Lashua testified that the Company would examine whether it is a viable option to purchase water from Harnett County, as suggested by at least one customer in this present proceeding; however, witness Lashua indicated that when such option was examined several years ago it was determined that the capital investment to interconnect to Harnett County would be substantial because Harnett County's mains are over two and one-half miles away from Carolina Trace's mains.

With respect to the amendments to the Applicant's current Schedule of Rates as requested by Carolina Trace in its application, Public Staff witness Vaughan testified that, with respect to the installation of an irrigation meter, Carolina Trace has stated that it would be as accommodating as possible with respect to a customer's desired irrigation meter location. However, according to the Company, the location of the original water meter would greatly influence any secondary installation and the customer would be responsible for water line extensions past the irrigation meter.

Further, the Public Staff found Carolina Trace's requested amendment to clarify the wording included in its tariff with respect to its reconnection charge and the Company's requested increase in its returned check charge from $10.00 to $20.00 to be reasonable. Such clarifying language and the increased charge were agreed to by the Stipulating Parties and included in the Stipulation.

Based upon the foregoing findings of fact and the entire record in this proceeding, the Commission is of the opinion that the provisions of the Stipulation between Carolina Trace and the Public Staff entered and filed on August 19, 2010, which are incorporated by reference herein, are just and reasonable and should be approved. Consequently, the levels of rate base, revenues, and expenses as set forth in the Stipulation and included in Stipulation Exhibit I are appropriate for use in this proceeding. Further, with respect to the wholesale rate Carolina Trace pays to the City of Sanford for purchased water for the Carolina Trace community, the Commission believes that the stipulated monthly reporting requirements regarding the Company's current negotiations with the City of Sanford for a lower rate as well as the Company's verbal commitment expressed at the August 26, 2010 evidentiary hearing, to examine the feasibility of an interconnection with Harnett County should adequately address the concerns expressed by the public witnesses regarding such matter.

Finally, with respect to the Company's ongoing problem with inflow and infiltration into the wastewater treatment plant and the resulting increase to operating expenses, the Commission requires Carolina Trace to continue its efforts to address this pending matter as timely as practicably possible in order to reduce its operating expenses in the future. Further, the Commission concludes that Carolina Trace should file a report in Docket No. W-1013, Sub 9, on a quarterly basis, which provides, at a minimum, the action(s) the Company has taken to reduce inflow and infiltration into the wastewater treatment plant; the action(s) the Company plans to take; and a comparison of the monthly wastewater treatment plant flow to the actual metered sewer usage (based upon metered water, before any reduction for maximum sewer billing of 10,000 gallons per monthly residential bill) stated in a manner which clearly sets forth the current magnitude of the problem in both gallons and as a percentage of total gallons treated.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 19

The evidence supporting this finding of fact is contained in the Partial Settlement Agreement entered on July 19, 2010 and filed on July 20, 2010.

The Partial Settlement Agreement contained the provision that provided the level of service being provided by Carolina Trace in all of its respective service areas in North Carolina is found to be adequate; the components of the rate of return should be as follows:

a. Long-Term Debt Ratio:	53.00%
b. Common Equity Ratio:	47.00%
c. Embedded Cost of Debt:	6.60%
d. Return on Common Equity:	10.25%
e. Overall Weighted Rate of Return:	8.32%

Such provision also stated that Carolina Trace and the Public Staff agreed to the following: (1) the capitalization ratios reflect a hypothetical capital structure for Utilities, Inc., which is the parent company of Carolina Trace; (2) the embedded cost of debt is Utilities, Inc.'s actual cost rate; and (3) the return on common equity is based upon an estimate.

The Commission has carefully reviewed the evidence relating to the stipulated capital structure, the return on common equity, and the overall rate of return and concludes that the provisions of the Partial Settlement Agreement, entered on July 19, 2010 and filed on July 20, 2010, which is incorporated by reference herein, are just and reasonable and should be approved. Such stipulated overall rate of return will allow the Applicant the opportunity to produce a fair return for its shareholders, considering changing economic conditions and other factors, as they now 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 fair to its customers and its existing investors.

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

The evidence for these findings of facts is contained in the Stipulation and in the testimony of Carolina Trace witness Lashua.

The Parties entered into a Stipulation that settled their outstanding issues on August 19, 2010. In the Stipulation, Carolina Trace agreed to do the following: (1) update the Public Staff on a monthly basis regarding the status of negotiations with the City of Sanford for a lower purchased water rate beginning August 31, 2010; (2) provide notice on its monthly bills advising that customers may contact Carolina Trace to discontinue water utility service during an extended absence from their residence; such notice should also advise customers that they are responsible for reconnection charges during their absence and that their liability for base charges will depend upon the duration of the period of discontinued use as described in the Schedule of Rates for this docket; customers should only be assessed the base charge as described on the Schedule of Rates but should not be billed for water and/or sewer usage charges during the discontinued-use time period; and (3) provide periodic employee training on its customer service policies and response procedures.

Based upon the foregoing, the Commission finds and concludes that the aforementioned, agreed-upon recommendations are appropriate and that Carolina Trace should comply with such provisions. Further, the Commission is of the opinion that Carolina Trace should file with the Commission, in Docket No. W-1013, Sub 9, its monthly update to the Public Staff regarding the status of negotiations with the City of Sanford for a lower purchased water rate. Such filing should also include an update regarding the Company's investigation of an interconnection with Harnett County as well as an update regarding any other efforts the Company has made or plans to make to reduce its purchased water expense.

Finally, due to the numerous customer concerns regarding Carolina Trace's customer service policies and response procedures, the Commission finds and concludes that the Company should provide the stipulated periodic employee training, at a minimum, on a semi-annual basis and that Carolina Trace should include each year with its annual report filing a statement detailing the dates of the training; the location of the training; the number of persons trained, including whether such employees interact with North Carolina customers on a regular basis; and a detailed outline of the training topics.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 30 AND 31

The evidence supporting these findings of fact is contained in the testimony of Public Staff witnesses Fernald and Vaughan; in the testimony of Carolina Trace witnesses Shrake and Lashua; in the Partial Settlement Agreement; and in the Stipulation. Based on the foregoing findings and rulings and the entire record in this proceeding, the Commission concludes that all of the provisions of the Partial Settlement Agreement and the Stipulation, taken together, are just and reasonable under the circumstance of these proceedings and should be approved.

IT IS, THEREFORE, ORDERED as follows:

1. That Carolina Trace is authorized to increase its rates and charges for water and sewer utility service in the Carolina Trace Development in Lee County, North Carolina, as reflected in the Schedule of Rates, attached hereto as Appendix A. Such rates and charges shall be effective for service rendered on and after the issuance date of this Order.

2. That the Schedule of Rates attached hereto as Appendix A, is hereby approved and deemed filed with the Commission pursuant to G.S. 62-138.

3. That the Notice to Customers, attached hereto as Appendix B, shall be mailed with sufficient postage or hand delivered to all affected customers in conjunction with the next regularly scheduled billing process, and that the Applicant shall submit the attached Certificate of Service, properly signed and notarized, not later than 45 days after the issuance date of this Order.

4. That the Stipulation between the parties to this proceeding as well as the Partial Settlement Agreement, incorporated by reference, herein, are hereby approved.

5. That neither the Partial Settlement Agreement entered on July 19, 2010, the Stipulation entered on August 19, 2010, nor this Order shall be cited or treated as precedent in future proceedings.

6. That Carolina Trace shall update the Public Staff on a monthly basis regarding the status of negotiations with the City of Sanford for a lower purchased water rate, as stipulated. Such update shall be filed with the Commission in Docket No. W-1013, Sub 9, and shall also include an update regarding the Company's investigation of an interconnection with Harnett County as well as an update regarding any other efforts the Company has made or plans to make to reduce its purchased water expense.

7. That Carolina Trace shall provide notice on its monthly bills advising that customers may contact the Company to discontinue water utility service during an extended absence from their residence, as stipulated. Said notice shall also advise customers that they are responsible for reconnection charges during their absence and that their liability for base charges will depend upon the duration of the period of discontinued use as described in the Schedule of Rates for this docket, as stipulated. Carolina Trace shall only assess customers the base charge as described on the Schedule of Rates but shall not bill customers for water and/or sewer usage charges during the discontinued-use time period, as stipulated.

8. That Carolina Trace shall periodically provide employee training on its customer service policies and response procedures, as stipulated. Such periodic employee training shall be provided, at a minimum, on a semi-annual basis. Carolina Trace shall provide each year with its annual report filing a statement detailing the dates of the employee training; the location of the training; the number of persons trained, including whether such employees interact with North Carolina customers on a regular basis; and a detailed outline of the training topics.

9. That Carolina Trace shall file a report in Docket No. W-1013, Sub 9, on a quarterly basis, which provides, at a minimum, the action(s) the Company has taken to reduce inflow and infiltration into the wastewater treatment plant; the action(s) the Company plans to take; and a comparison of the monthly wastewater treatment plant flow to the actual monthly

metered sewer usage (based upon metered water, before any reduction for maximum sewer billing of 10,000 gallons per monthly residential bill) stated in a manner which clearly sets forth the current magnitude of the problem in both gallons and as a percentage of total gallons treated.

ISSUED BY ORDER OF THE COMMISSION.
This the 24th day of November, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Patricia Swenson, Deputy Clerk

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APPENDIX A
PAGE 1 OF 3

SCHEDULE OF RATES

for

CAROLINA TRACE UTILITIES, INC.

for providing water and sewer utility service in

CAROLINA TRACE DEVELOPMENT

Lee County, North Carolina

Monthly Metered Water Utility Service:

Base charge, zero usage	$14.65 minimum
Usage charge, per 1,000 gallons	$ 5.28

Monthly Metered Sewer Utility Service: [1/, 2/]

Base charge, zero usage	$37.86 minimum
Usage charge, per 1,000 gallons	$ 8.96

1/ Residential sewer usage bills are based on metered water usage and are limited to payment for 10,000 gallons per month, i.e., "Residential Usage Charges" may not exceed $89.60 (for 10,000 gallons), with total sewer bill not to exceed $127.46.

2/ Commercial sewer usage bills are based on total metered water usage, i.e., are not limited to a maximum volume or charge.

WATER AND SEWER – RATE INCREASE

Tap-on Fee:

Water service connection	$605.00
Sewer service connection	$533.00

Irrigation Meter Installation: Actual Cost

Reconnection Charge:

If water service is cut off by utility for good cause	$ 27.00
If water service is cut off by utility at customer's request	$ 27.00
If sewer service cut off by utility for good cause by any method other than above	Actual Cost

Reconnection Charge (con't):

Customers who ask to be reconnected within nine months of disconnection will be billed for the approved monthly base charge for each month they were disconnected.

If payment for water and/or sewer utility service is not received by the past-due date, customers may, in addition to all past-due and current charges, have to pay late payment finance charges, in order to avoid having water and/or sewer service disconnected.

To resume water and/or sewer utility service after discontinuance for good cause, customers must pay the reconnection charge(s) discussed above, plus any delinquent water and/or sewer bill(s), including finance charges.

Rule R10-16(f): Whenever sewer service is discontinued for any reason the utility shall send a report of termination of service to the local county board of health.

Neglect or failure to pay amounts due or to otherwise fail to comply with provisions of this tariff shall be deemed to be sufficient cause for discontinuance of service. Prior to disconnection, Carolina Trace Utilities, Inc. (CTU), will diligently try to induce the customer to pay or otherwise comply with the tariff. After such effort, CTU will give the customer written notice of at least five days (excluding Sundays and holidays) prior to disconnection. Such notice will contain, at a minimum, a copy of this provision, and a description of the procedures which CTU will perform to discontinue service.

In the event that an emergency or dangerous condition is found to exist, or fraudulent use of the wastewater system is detected, sewer utility service may be cut off without such notice. In such an event, notice as described above will be given as soon as possible.

If discontinuance of sewer service becomes necessary, CTU will install a valve or other device to cut off and/or block the sewer line. Prior to installing the valve or device, CTU will provide to the customer a detailed good faith estimate of the actual cost of disconnection.

APPENDIX A
PAGE 3 OF 3

New Customer Charge:

Water utility service	\$27.00
Sewer utility service	\$27.00 [3/]

[3/] This charge will be waived if sewer customer is also a water customer.

Meter Testing Fee:

Testing requested by customer once in 24 months	No Charge
Testing requested by customer more than once in 24 months	\$20.00 [4/]

[4/] If the meter is found to register in excess of the prescribed accuracy limits, the testing charge will be waived. If the meter is found to register accurately or below prescribed accuracy limits, the charge will be due, i.e., retained by CTU.

Returned Check Charge:	\$20.00
Bills Due:	On billing date
Bills Past Due:	15 days after billing date
Billing Frequency:	Shall be monthly for service in arrears
Finance Charges for Late Payment:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-1013, Sub 9 on this the 24th day of November, 2010.

APPENDIX B
PAGE 1 OF 3

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-1013, SUB 9

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Carolina Trace Utilities, Inc., 2335 Sanders Road, Northbrook, Illinois 60062, for Authority to Increase Rates for Water and Sewer Utility Service in the Carolina Trace Development in Lee County, North Carolina	)	**NOTICE TO CUSTOMERS**

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission has issued an Order authorizing Carolina Trace Utilities, Inc. to charge increased rates for water and sewer utility service in all of its service areas in Lee County, North Carolina. The new approved rates are as follows:

Monthly Metered Water Utility Service:

Base charge, zero usage	$14.65 minimum
Usage charge, per 1,000 gallons	$ 5.28

Monthly Metered Sewer Utility Service: [1/, 2/]

Base charge, zero usage	$37.86 minimum
Usage charge, per 1,000 gallons	$ 8.96

[1/] Residential sewer usage bills are based on metered water usage and are limited to payment for 10,000 gallons per month, i.e., "Residential Usage Charges" may not exceed $89.60 (for 10,000 gallons), with total sewer bill not to exceed $127.46.

[2/] Commercial sewer usage bills are based on total metered water usage, i.e., are not limited to a maximum volume or charge.

Tap-on Fee:

Water service connection	$605.00
Sewer service connection	$533.00

Irrigation Meter Installation:	Actual Cost
Reconnection Charge:	
If water service is cut off by utility for good cause	\$ 27.00
If water service is cut off by utility at customer's request	\$ 27.00
If sewer service cut off by utility for good cause by any method other than above	Actual Cost

Customers who ask to be reconnected within nine months of disconnection will be billed for the approved monthly base charge for each month they were disconnected.

If payment for water and/or sewer utility service is not received by the past-due date, customers may, in addition to all past-due and current charges, have to pay late payment finance charges, in order to avoid having water and/or sewer service disconnected.

To resume water and/or sewer utility service after discontinuance for good cause, customers must pay the reconnection charge(s) discussed above, plus any delinquent water and/or sewer bill(s), including finance charges.

Rule R10-16(f): Whenever sewer service is discontinued for any reason the utility shall send a report of termination of service to the local county board of health.

Neglect or failure to pay amounts due or to otherwise fail to comply with provisions of this tariff shall be deemed to be sufficient cause for discontinuance of service. Prior to disconnection, Carolina Trace Utilities, Inc. (CTU), will diligently try to induce the customer to pay or otherwise comply with the tariff. After such effort, CTU will give the customer written notice of at least five days (excluding Sundays and holidays) prior to disconnection. Such notice will contain, at a minimum, a copy of this provision, and a description of the procedures which CTU will perform to discontinue service.

In the event that an emergency or dangerous condition is found to exist, or fraudulent use of the wastewater system is detected, sewer utility service may be cut off without such notice. In such an event, notice as described above will be given as soon as possible.

If discontinuance of sewer service becomes necessary, CTU will install a valve or other device to cut off and/or block the sewer line. Prior to installing the valve or device, CTU will provide to the customer a detailed good faith estimate of the actual cost of disconnection.

WATER AND SEWER – RATE INCREASE

APPENDIX B
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New Customer Charge:

Water utility service	\$27.00
Sewer utility service	\$27.00 [3/]

[3/] This charge will be waived if sewer customer is also a water customer.

Meter Testing Fee:

Testing requested by customer once in 24 months	No Charge
Testing requested by customer more than once in 24 months	\$20.00 [4/]

[4/] If the meter is found to register in excess of the prescribed accuracy limits, the testing charge will be waived. If the meter is found to register accurately or below prescribed accuracy limits, the charge will be due, i.e., retained by CTU.

Returned Check Charge:	\$20.00
Bills Due:	On billing date
Bills Past Due:	15 days after billing date
Billing Frequency:	Shall be monthly for service in arrears
Finance Charges for Late Payment:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date.

ISSUED BY ORDER OF THE COMMISSION.
This the 24th day of November, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Patricia Swenson, Deputy Clerk

WATER AND SEWER – RATE INCREASE

CERTIFICATE OF SERVICE

I, ____, mailed with sufficient postage or hand delivered to all affected customers the attached Notice to Customers issued by the North Carolina Utilities Commission in Docket No. W-1013, Sub 9, and the Notice was mailed or hand delivered by the date specified in the Order.

This the _____ day of __________________, 2010.

By: ______________________________

Signature

____

Name of Utility Company

The above named Applicant, ______________________________, personally appeared before me this day and, being first duly sworn, says that the required Notice to Customers was mailed or hand delivered to all affected customers, as required by the Commission Order dated ______________________ in Docket No. W-1013, Sub 9.

Witness my hand and notarial seal, this the ____ day of ______________, 2010.

____

Notary Public

____

Address

(SEAL) My Commission Expires: ______________________________

Date

DOCKET NO. W-1240, SUB 6

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Chatham Utilities, Inc., Post Office Box 2359, Swansboro, North Carolina 28584-2369, for Authority to Increase Rates for Water and Sewer Utility Service in Chatham Estates Manufactured Housing Community in Wake County, North Carolina	ORDER DENYING INTERIM RATE RELIEF, SCHEDULING HEARING, AND REQUIRING CUSTOMER NOTICE

BY THE COMMISSION: On September 3, 2010, Chatham Utilities, Inc. (Applicant or Chatham), filed an application with the Commission seeking authority to increase its rates for water and sewer utility service in Chatham Estates Manufactured Housing Community in Wake County, North Carolina. On September 17, 2010, the Applicant filed a motion to implement interim rates and for expedited review of the motion, stating that financial projections of the expected revenues and direct expenses of the Applicant during the rate case would result in a cash flow shortfall which would jeopardize the short-term financial viability of the Applicant. On October 1, 2010, the Commission issued an order establishing a general rate case and suspending rates.

The Public Staff stated that it had investigated the request for interim rate relief and recommended denial based upon its conclusion that no financial emergency exists and there is no cash flow situation that would warrant approval of interim rates. The Public Staff also recommended that this matter be scheduled for hearing subject to cancellation if no significant protests are received within the notice period.

The Commission agrees with the Public Staff that, as a general policy, interim rates are justified only in the case of a "financial emergency" that affects the utility's present ability to provide adequate service. A "financial emergency" is defined as an actual cash flow deficit prohibiting the payment of ongoing normal operating expenses. In determining whether an emergency exists, per books numbers should be used rather than pro forma numbers, and non-cash items should not be considered. Based on the per books amounts shown on the application, the Applicant has a positive cash flow of $9,717. As a result, the Commission concludes the proposed interim rates should be denied and the matter should be scheduled for public hearing subject to being canceled if no significant protests are received subsequent to public notice.

IT IS, THEREFORE, ORDERED as follows:

1. That the Applicant's request for interim rates is denied.

2. That the application is scheduled for public hearing at 7:00 p.m., on Wednesday, January 19, 2011, in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury

Street, Raleigh, North Carolina, subject to being canceled if no significant protests are received subsequent to customer notice.

3. That the Notice to Customers, attached as Appendix A, be mailed with sufficient postage or hand delivered by the Applicant to all customers no later than 10 days after the date of this Order; and that the Applicant submit to the Commission the attached Certificate of Service properly signed and notarized not later than 20 days after the date of this Order.

4. That an officer or representative of the Applicant is required to appear in person before the Commission at the time and place of the hearing to testify concerning the information contained in the application. If the Applicant desires to cross-examine any witnesses at the hearing, the Applicant shall be represented by legal counsel at this hearing.

ISSUED BY ORDER OF THE COMMISSION.
This the 4th day of November, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Gail L Mount, Deputy Clerk

rb110110.02

Commissioner William T. Culpepper, III, did not participate.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

APPENDIX A
PAGE 1 OF 3

NOTICE TO CUSTOMERS
DOCKET NO. W-1240, SUB 6
BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

Notice is given that Chatham Utilities, Inc., Post Office Box 2359, Swansboro, North Carolina 28584, has filed an application with the North Carolina Utilities Commission for authority to increase rates for water and sewer utility service in Chatham Estates Manufactured Housing Community in Wake County, North Carolina, as follows:

WATER AND SEWER – RATE INCREASE

	Present	Proposed
Monthly Metered Water Rates:		
Base charge, zero usage	$ 9.03	$16.83
Usage charge, per 1,000 gallons	$ 4.79	$ 5.06
Monthly Metered Sewer Rates:		
Base charge, zero usage	$ 12.00	$ 12.00
Usage charge, per 1,000 gallons	$ 6.82	$ 7.07

The Commission may consider additional or alternative rate design proposals that were not included in the original application and may order increases or decreases in the schedules that differ from those proposed by the Applicant. However, any rate structure considered will not generate more overall revenues than requested.

EFFECT OF PROPOSED RATES

The average monthly residential water bill would increase from $26.71 to $35.50 (32.9%), based upon usage of 3,690 gallons.

The average monthly residential sewer bill would increase from $37.17 to $38.09 (2.5%), based upon usage of 3,690 gallons.

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PROCEDURE FOR PUBLIC HEARING:

The Commission has scheduled the application for public hearing as follows:

Raleigh, North Carolina: At 7:00 p.m., on Wednesday, January 19, 2011, Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street.

This hearing may be canceled and the matter decided on the filings if no significant protests are received from consumers within 45 days of the date of this notice.

The Public Staff is authorized by statute to represent consumers in proceedings before the Commission. Written statements/protests to the Public Staff should include any information that the writer wishes to be considered by the Public Staff in its investigation of the matter. These statements should be addressed to Mr. Robert Gruber, Executive Director, Public Staff, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326. Written statements/protests can also be faxed to Public Utilities Engineer Bruce Vaughan at (919) 715-6704, or e-mailed to bruce.vaughan@psncuc.nc.gov.

WATER AND SEWER – RATE INCREASE

The Attorney General is also authorized by statute to represent consumers in proceedings before the Commission. Statements/protests to the Attorney General should be addressed to The Honorable Roy Cooper, Attorney General, 9001 Mail Service Center, Raleigh, North Carolina 27699-9001.

Written statements are not evidence unless the persons submitting the statements appear at the public hearing and testify concerning the information contained in their written statements.

Persons desiring to present testimony concerning their opinion on this application or on any service problems they may be experiencing may appear at the public hearing and give such testimony.

Persons desiring to intervene in the matter as formal parties of record should file a motion under North Carolina Utilities Commission Rules R1-6, R1-7, and R1-19 no later than 45 days after the date of this notice. These motions should be filed with the North Carolina Utilities Commission, 4325 Mail Service Center, Raleigh, North Carolina 27699-4325.

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The details of the proposed new rates have been filed with the North Carolina Utilities Commission. A copy of the application and all filings in this matter are available for review by the public at the Office of the Chief Clerk, 430 North Salisbury Street, Raleigh, North Carolina. Upon request, the Chief Clerk will place a copy of the application and all filings in centrally located libraries where they may be copied without prohibition. Such requests may be made by writing to the Chief Clerk, North Carolina Utilities Commission, 4325 Mail Service Center, Raleigh, North Carolina, by providing the name and address of the library to which the information is to be mailed. Information regarding this proceeding can also be accessed from the Commission's website at www.ncuc.net.

This the 4th day of November, 2010.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

WATER AND SEWER – RATE INCREASE

CERTIFICATE OF SERVICE

I, ____, mailed with sufficient postage or hand delivered to all affected customers the attached Notice to Customers issued by the North Carolina Utilities Commission in Docket No. W-1240, Sub 6, and the Notice was mailed or hand delivered by the date specified in the Order.

This the _____ day of ____________________, 2010.

By: ______________________________

Signature

____

Name of Utility Company

The above named Applicant, ____________________________, personally appeared before me this day and, being first duly sworn, says that the required Notice to Customers was mailed or hand delivered to all affected customers, as required by the Commission Order dated __________________ in Docket No. W-1240, Sub 6.

Witness my hand and notarial seal, this the ____ day of ______________, 2010.

____

Notary Public

____

Address

(SEAL) My Commission Expires: ______________________________

Date

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(Azalea Mobile Home Park)	WR-1002, SUB 0	(03/22/2010)
(Otter Creek Mobile Home Park)	WR-1002, SUB 1	(03/22/2010)
Carlyle Centennial Creek, LLC		
(Century Creek Apartments)	WR-989, SUB 0	(02/17/2010)
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(Carolina Village Mobile Home Park)	WR-1013, SUB 0	(05/11/2010)
Cato; Charles E.		
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East Pointe Partners, LLC *(Stanford Reserve Apartments)*	WR-966, SUB 0	(01/25/2010)
EEA-North Pointe, LLC *(Sherwood Station Apartments)*	WR-1028, SUB 0	(08/05/2010)
Ewing; Roy & Frances *(Pine Valley Mobile Home Park)*	WR-994, SUB 0 W-1131, SUB 8	(03/02/2010)
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(Woodcroft Apartments)	WR-985, SUB 0	(01/12/2010)
Morgan; Philip Edward		
(Clover Creek Village II MHP)	WR-1006, SUB 0	(04/13/2010)
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(Catalyst Apartments)	WR-1005, SUB 0	(04/06/2010)
Oakhurst Farms of Raleigh, LLC		
(Village of Pickwick Apartments)	WR-1018, SUB 0	(06/14/2010)
Plantation Park Apartments, Inc.		
(Plantation Park Apartments)	WR-644, SUB 4	(11/16/2010)
Rehobeth Pointe, LLC		
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Schrader Family Limited Partnership		
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Westcliffe Apartments)	WR-980, SUB 1	(02/17/2010)
(Dover Apartments)	WR-980, SUB 2	(09/23/2010)
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(Beech Lake Apartments)	WR-1025, SUB 0	(08/16/2010)
Tanglewood Lake Apartments, LLC		
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Wesley Village Development, LP		
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(Andover Woods Apartments)	WR-693, SUB 3	(07/07/2010)
Sagebrush Courtney Oaks Apts., LLC		
(Courtney Oaks Apartments)	WR-567, SUB 4	(07/07/2010)
Sagebrush Waterford Creek Apts., LLC. et al.		
(Waterford Creek Apartments)	WR-542, SUB 5	(07/07/2010)

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Company	Docket No.	Date
Salem Village Apartments, LLC		
(Salem Village Apartments)	WR-446, SUB 4	(07/19/2010)
SH Pool A Sunstone, LLC		
(Sunstone Apartments)	WR-694, SUB 3	(02/08/2010)
Shadowood Apartments, LLC		
(Shadowood Apartments)	WR-903, SUB 1	(01/25/2010)
(Shadowood Apartments)	WR-903, SUB 2	(09/01/2010)
Shoreline, LLC		
(Long Leaf Mobile Home Park)	WR-530, SUB 2	(10/04/2010)
Silverstone Apartments, LLC		
(Silverstone Apartments)	WR-902, SUB 1	(01/25/2010)
(Silverstone Apartments)	WR-902, SUB 2	(08/24/2010)
Social Thornberry, Inc.		
(Thornberry Apartments)	WR-106, SUB 7	(03/17/2010)
(Thornberry Apartments)	WR-106, SUB 8	(04/13/2010)
South Terrace Apts. North Carolina, LLC		
(South Terrace at Auburn Apts.)	WR-689, SUB 1	(12/01/2010)
Southern Village Apartments, LLC		
(Southern Village Apartments)	WR-338, SUB 6	(10/18/2010)
Southwood Realty Company		
(Carriage House Apartments)	WR-910, SUB 4	(09/24/2010)
(Quail Woods Apartments)	WR-910, SUB 5	(09/24/2010)
Sovereign Development Co., LLC		
(Willow Woods Apartments)	WR-784, SUB 2	(11/30/2010)
Spring Forest TIC, LLC		
(Spring Forest at Deerfield Apts.)	WR-450, SUB 2	(08/30/2010)
Spring Ridge Apartments, LLC		
(Spring Ridge Apartments)	WR-725, SUB 1	(11/24/2010)
St. Andrews Place Apts., LLC		
(Colonial Grand at Wilmington Apts.)	WR-111, SUB 7	(06/01/2010)
Steele Creek Apt. Properties, LLC		
(The Park at Steele Creek Apts.)	WR-186, SUB 7	(08/09/2010)
Steelecroft Farm, LLC		
(Steelecroft Farms Apts.)	WR-688, SUB 1	(03/23/2010)
(Steelecroft Farms Apts.)	WR-688, SUB 2	(08/18/2010)
Steeplechase Triad Apt. Portfolio, LLC		
(Steeplechase Apartments)	WR-497, SUB 3	(09/22/2010)
Sterling Morrison Apartments, LLC		
(Sterling Morrison Apts.)	WR-643, SUB 2	(09/21/2010)
Stonecreek Apts. of Mooresville, LP		
(Stonecreek Apartments)	WR-390, SUB 3	(08/31/2010)

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Company	Docket No.	Date
Strawberry Hill Associates, LP		
(Strawberry Hills Apartments)	WR-293, SUB 5	(07/19/2010)
Summermill Properties, LLC		
(Summermill at Falls River Apts.)	WR-395, SUB 3	(08/24/2010)
Summit Grandview, LLC		
(Camden Grandview Apts.)	WR-547, SUB 4	(08/05/2010)
Suncoast Cornerstone, LLC, et al.		
(Cornerstone Apartments)	WR-801, SUB 2	(02/22/2010)
Suncoast North Park, LLC		
(North Park Apartments)	WR-808, SUB 2	(01/04/2010)
The Forest at Asheville Properties, LLC		
(The Forest at Biltmore Park Apts.)	WR-20, SUB 5	(09/22/2010)
TAU Valley, LLC		
(Tau Valley Apartments)	WR-823, SUB 2	(09/29/2010)
The Apartments at Crossroad, LLC		
(Legacy Crossroads Apts.)	WR-851, SUB 1	(03/15/2010)
The Carlisle Apartments, LP		
(Phillips Univ. Center Apts.)	WR-923, SUB 2	(11/22/2010)
The Cloisters at Steelecroft, LLC		
(The Cloisters at Steelecroft Apts.)	WR-958, SUB 1	(08/02/2010)
The Fairway Apartments, LLC et al.		
(The Links Apartments)	WR-565, SUB 1	(08/23/2010)
The Grand on Julian, LLC		
(The Grand on Julian Apts.)	WR-690, SUB 1	(09/29/2010)
The Pointe at Chapel Hill Apts., LLC		
(The Pointe at Chapel Hill Apts.)	WR-1033, SUB 1	(10/19/2010)
The Tradition at Mallard Creek, LLC		
(Tradition at Mallard Creek Apts.)	WR-353, SUB 1	(12/21/2010)
The Village at Carver Falls II, LLC		
(The Village at Carver Falls Apts.)	WR-563, SUB 1	(10/25/2010)
Timber Crest Apartments, LLC		
(Colonial Vil. at Timber Crest Apts.)	WR-412, SUB 5	(07/08/2010)
TMP Lodge at Crossroads, LLC		
(The Lodge at Crossroads Apts.)	WR-799, SUB 1	(08/23/2010)
Tower Place, L.L.C		
(Tower Place Apartments)	WR-108, SUB 7	(11/08/2010)
Tradition at Stonewater I, LP		
(The Tradition at Stonewater Apts., Phase I)	WR-931, SUB 1	(08/23/2010)
Tremont Partners, LP		
(Ashton Southend Apts.)	WR-963, SUB 1	(08/16/2010)

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Company	Docket No.	Date
Treybrooke Village Apartments, L.L.C.		
(Treybrooke Village Apartments)	WR-379, SUB 5	(11/22/2010)
Treybrooke, LLC		
(Treybrooke Apartments)	WR-824, SUB 1	(10/18/2010)
Trinity Commons Apartments, LLC		
(Col. Grand at Trinity Commons Apts.)	WR-415, SUB 5	(09/07/2010)
Troy Village Acquisition Company		
(Windsor at Tryon Village Apts.)	WR-750, SUB 2	(08/23/2010)
Twin Cedars, L.P.		
(Twin Cedars II Apartments)	WR-225, SUB 3	(03/01/2010)
VAC L.L.L.P.		
(Chapel Tower Apartments)	WR-831, SUB 42	(08/06/2010)
(Duke Manor Apartments)	WR-831, SUB 43	(08/06/2010)
(Colonial Townhomes Apts.)	WR-831, SUB 44	(08/06/2010)
(Holly Hills Apartments)	WR-831, SUB 45	(08/06/2010)
(Knollwood Apartments)	WR-831, SUB 46	(08/23/2010)
(Estes Park Apartments)	WR-831, SUB 47	(09/07/2010)
(Kingswood Apts.)	WR-831, SUB 48	(09/07/2010)
(Franklin Woods Apts.)	WR-831, SUB 49	(09/07/2010)
(Pinegate Apts.)	WR-831, SUB 50	(09/07/2010)
(Booker Creek Apts.)	WR-831, SUB 51	(09/07/2010)
(Royal Park Apts.)	WR-831, SUB 52	(09/07/2010)
(Univ. Lake Apts.)	WR-831, SUB 53	(09/07/2010)
(Rosewood Apts.)	WR-831, SUB 54	(09/07/2010)
(Briarwood Apts.)	WR-831, SUB 55	(09/07/2010)
(Oakwood Apts.)	WR-831, SUB 56	(09/07/2010)
(Princeton Apts.)	WR-831, SUB 57	(09/07/2010)
(Eastwood Apts.)	WR-831, SUB 58	(09/07/2010)
(Duke Court Apts.)	WR-831, SUB 59	(09/07/2010)
(Oaktree Apts.)	WR-831, SUB 60	(09/07/2010)
(Chesterfield Apts.)	WR-831, SUB 61	(09/07/2010)
(Duke Villa Apts.)	WR-831, SUB 62	(09/07/2010)
(Brook Hill Apts.)	WR-831, SUB 63	(11/29/2010)
Vanstory Apartments, LLC		
(Ashbrook Pointe Apartments)	WR-126, SUB 5	(04/13/2010)
(Ashbrook Pointe Apartments)	WR-126, SUB 6	(07/28/2010)
Verde Apartments, L.P		
(Alta Verde Apartments)	WR-806, SUB 1	(08/23/2010)
Village at Cliffdale Apartments		
(Village at Cliffdale Apts.)	WR-842, SUB 1	(04/26/2010)
Village Rental Company, LLC		
(Villager Apartments)	WR-468, SUB 3	(08/30/2010)

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Company	Docket No.	Date
Wakefield Affordable Housing, LLC		
(Wakefield Hills Apartments)	WR-685, SUB 2	(03/01/2010)
Walden/Greenfields Associates, LP		
(Sagebrush of Chapel Hill Apts.)	WR-287, SUB 4	(11/01/2010)
Walnut Ridge Partners, Ltd.		
(Walnut Ridge Apartments)	WR-152, SUB 5	(02/17/2010)
(Walnut Ridge Apartments)	WR-152, SUB 6	(09/07/2010)
(Walnut Ridge Apartments)	WR-152, SUB 7	(12/06/2010)
Waterford Lakes Partners, LLC		
(Waterford Lakes Apts.)	WR-731, SUB 2	(09/21/2010)
Waterford Village Gardens Assoc., LLC		
(Waterford Village Apartments)	WR-404, SUB 3	(05/10/2010)
Wembley Apartments, LLC		
(Wembley Apartments)	WR-1017, SUB 1	(08/16/2010)
West Market Partners, LLC		
(The Amesbury on West Market Apts.)	WR-749, SUB 2	(11/29/2010)
Westdale Arrowhead Crossing NC, LLC		
(Arrowhead Crossing Apts.)	WR-634, SUB 3	(07/26/2010)
Westdale Chase on Monroe NC, LLC		
(Chase on Monroe Apartments)	WR-635, SUB 3	(08/12/2010)
Westdale NC Summit Creek, L.P.		
(Johnston Creek Crossing Apts.)	WR-826, SUB 2	(07/26/2010)
Westdale Peppertree, Ltd.		
(Peppertree Apartments)	WR-815, SUB 2	(07/26/2010)
Westdale Poplar Place, LLC		
(Poplar Place Apartments)	WR-816, SUB 3	(11/23/2010)
Westdale Sabal Point NC, LLC		
(Sabal Point Apartments)	WR-636, SUB 3	(07/26/2010)
Westdale Willow Glen NC, LLC		
(Willow Glen Apartments)	WR-633, SUB 3	(08/12/2010)
Westfield Thorngrove, LLC		
(Thorngrove Apartments)	WR-906, SUB 2	(08/11/2010)
Westmont Commons Apts., LLC		
(Westmont Commons Apartments)	WR-459, SUB 4	(09/22/2010)
WF Elizabeth, LLC		
(Elizabeth Square Apartments)	WR-868, SUB 1	(08/23/2010)
WMCi Raleigh I, LLC		
(Bexley at Preston Apartments)	WR-327, SUB 5	(07/19/2010)
WMCi Raleigh II, LLC		
(Bexley Park Apartments)	WR-317, SUB 5	(07/19/2010)

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WMCi Raleigh III, LLC		
(Bexley at Brier Creek Apts.)	WR-754, SUB 5	(07/27/2010)
(Bexley at Brier Creek Apts.)	WR-754, SUB 6	(11/23/2010)
WMCi Raleigh IV, LLC		
(Bexley at Heritage Apts.)	WR-803, SUB 1	(07/27/2010)
WMCi Raleigh V, LLC		
(Bexley at Carpenter Village Apts.)	WR-949, SUB 2	(07/20/2010)
WMCi Charlotte I, LLC		
(Bexley Commons at Rosedale Apts.)	WR-213, SUB 8	(07/14/2010)
WMCi Charlotte II, LLC		
(Bexley Creekside Apartments)	WR-230, SUB 7	(07/14/2010)
WMCi Charlotte III, LLC		
(Bexley at Lake Norman Apts.)	WR-258, SUB 7	(07/14/2010)
WMCi Charlotte IV, LLC		
(Bexley Crossing at Providence Apts.)	WR-269, SUB 7	(07/14/2010)
WMCi Charlotte V, LLC		
(Bexley at Springs Farm Apts.)	WR-340, SUB 6	(07/14/2010)
WMCi Charlotte VI, LLC		
(Bexley at Concord Mills Apts.)	WR-371, SUB 5	(07/14/2010)
WMCi Charlotte VII, LLC		
(Bexley at Davidson Apts.)	WR-392, SUB 5	(07/14/2010)
WMCi Charlotte VIII, LLC		
(Bexley at Matthews Apts.)	WR-466, SUB 5	(07/14/2010)
WMCi Charlotte IX, LLC		
(Bexley Greenway Apts.)	WR-467, SUB 5	(07/14/2010)
WMCi Charlotte X, LLC		
(Bexley at Harborgate Apts.)	WR-638, SUB 3	(07/14/2010)
Woodfield Glen, LLC		
(Woodfield Glen Apartments)	WR-800, SUB 2	(08/23/2010)
Woodlake Downs Associates, L.P.		
(Woodlake Downs Apartments)	WR-286, SUB 4	(01/04/2010)
(Woodlake Downs Apartments)	WR-286, SUB 5	(10/18/2010)
(Woodlake Downs Apartments)	WR-286, SUB 6	(12/21/2010)
100 Rock Haven, LLC		
(Rock Creek Apartments)	WR-992, SUB 1	(04/08/2010)
(Rock Creek Apartments)	WR-992, SUB 2	(11/03/2010)
100 Spring Meadow Dr. Apts. Investors		
(Alta Springs Apartments)	WR-47, SUB 6	(06/23/2010)
1100 NC West, LLC		
(Laurel Ridge Apts., Phase I)	WR-986, SUB 2	(11/02/2010)
(Laurel Ridge Apts., Phase II)	WR-986, SUB 3	(11/10/2010)

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1801 Interface Lane Apts. Investors, LLC		
(*Autumn Park Apartments*)	WR-521, SUB 3	(08/23/2010)
4209 Lassiter Mill Rd. Apts. Investors, LLC		
(*Alexan North Hills Apartments*)	WR-571, SUB 1	(08/23/2010)
712 Tucker Investors, LLC		
(*712 Tucker Apartments*)	WR-919, SUB 1	(03/02/2010)
(*712 Tucker Apartments*)	WR-919, SUB 2	(08/12/2010)

Abbington Place/Charlotte (Phase II), LLC -- WR-621, SUB 3; Errata Order *(Abbington Place Apts. - Phase II)* (09/17/2010)

BNP/Pepperstone, LLC -- WR-445, SUB 5; Errata Order *(Pepperstone Apts.)* (10/14/2010)

CH Realty III/Durham South Place -- WR-528, SUB 5; Order Dismissing Application and Closing Docket *(Alexan Place at South Square I Apts.)* (01/13/2010)

Courtney Ridge H.E., LLC -- WR-321, SUB 5; Errata Order *(Courtney Ridge Apts.)* (08/24/2010)

Duckett, Jr.; Gordon & Susan C. -- WR-928, SUB 1; Errata Order *(Forest Ridge MHP)* (10/14/2010)

Highland Quarters, LLC - WR-520, SUB 3; Errata Order *(Muirfield Village Apts.)* (03/30/2010)

Holly Hill Properties, LLC -- WR-192, SUB 4; Errata Order *(Holly Hill Apts.)* (10/14/2010)

JAX Commons, LLC -- WR-641, SUB 2; Errata Order *(Reserve at Jacksonville Commons Apts.)* (05/13/2010)

Panther Creek Apts., LLC -- WR-820, SUB 1; Errata Order *(Alexan Panther Creek Apts.)* (10/14/2010)

Spring Forest TIC, LLC -- WR-450, SUB 2; Errata Order *(Spring Forest at Deerfield Apts.)* (10/14/2010)

VAC L.L.L.P. -- WR-831, SUB 44; Errata Order *(Colonial Townhouse Apts.)* (10/14/2010)

Westdale Peppertree, L.P. -- WR-815, SUB 2; Errata Order *(Peppertree Apts.)* (07/26/2010)

WMCi Charlotte X, LLC -- WR-638, SUB 3; Errata Order *(Bexley Haborside Apts.)* (10/14/2010)

WMCi Raleigh IV, LLC -- WR-803, SUB 1; Reissued Order Approving Tariff Revision *(Bexley at Heritage Apartments)* (08/10/2010)

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APPENDIX A

P-100, Sub 165 – Working Group Matrix Recommendations[1]
February 2, 2010

Issue	NCUC Rule/Statute or Other	Description	Working Group Position for Subsection (h) Entities[2]	CompSouth	NCTIA	Public Staff
1	G.S. 62-35(c)	Depreciation	(i) Not applicable to retail services offered by Subsection (h) entities. (ii) Exemptions granted under Subsection (g) do not automatically apply to Subsection (h) entities. (iii) Subsection (h) entities should be exempted.	Agree with (i) and (ii).[3] Notwithstanding endnote 3, CompSouth does not presently foresee a need for the Commission to exercise authority to set depreciation rates for Subsection (h) entities.	Agree.	Agree.
2	G.S. 62-45	Determination of Cost and Value of Utility Property	(i) Not applicable to retail services offered by Subsection (h) entities. (ii) Exemptions granted under Subsection (g) do not automatically apply to Subsection (h) entities. (iii) Subsection (h) entities should be exempted.	Agree with (i) and (ii).[3] Notwithstanding endnote 3, CompSouth does not presently foresee a need for the Commission to ascertain or fix the cost or value of property for Subsection (h) entities.	Agree.	Agree.
3	G.S. 62-51	To Inspect Books and Records of Corporations Affiliated with Public Utilities	(i) Not applicable to retail services offered by Subsection (h) entities except as may relate to jurisdictional matters retained by Commission (e.g., universal service, TRS, etc.). (ii) Exemptions granted under Subsection (g) do not automatically apply to Subsection (h) entities. (iii) Subsection (h) entities should be exempted except as specified in (i) above.	Agree with (i) and (ii).[3]	Agree except for application to "jurisdictional matters retained by Commission (e.g. universal services, TRS, etc)" Subsection (h) electing companies will be providing financial information as stipulated in item 34 of the matrix. Inspection of the companies' books goes well beyond the need to monitor the financial wellbeing of the companies serving as COLR.	Agree.

Issue	NCUC Rule/Statute or Other	Description	Working Group Position for Subsection (h) Entities[2]	CompSouth	NCTIA	Public Staff
4	G.S. 62-73	Complaints	Not applicable to retail services offered by Subsection (h) entities.	Disagree. The Commission and other affected parties still have the right, granted by statute, to file complaints with Commission concerning retail services. The Commission's authority to resolve such complaints is limited by HB 1180. In addition, CLPs and LECs have independent authority under GS 62-133.5(c) to file complaints alleging anticompetitive activity under GS 62-73.	Agree. HB 1180 authority granted to the Public Staff and Commission in regards to the handling of complaints is addressed in Issue 5 below.	Agree.
5	G.S. 62-73.1	Complaints	This new section added by HB 1180 and, therefore, is unaffected by Subsection (h) election. The Working Group agrees that: (i) Public Staff and Commission have authority under this section to determine if actions of Subsection (h) entities are reasonable. (ii) Subsection (h) entities are required to provide customers with contact information per the language of the statute.	Agree.	Agree.	Agree.
6	G.S. 62-81	Special Procedure in Hearing and Deciding Rate Cases	(i) Not applicable to retail services offered by Subsection (h) entities. (ii) Exemptions granted under Subsection (g) do not automatically apply to Subsection (h) entities. (iii) Applicability to non-retail services provided by Subsection (h) entities will be addressed in future comments on non-retail regulation of Subsection (h) entities.	Agree.	Agree.	Agree.
7	G.S. 62-110	Certification Requirements for Long Distance Providers, PSPs, STS and Other Providers	Not affected by HB 1180.	Agree.	Agree.	Agree.

Issue	NCUC Rule/Statute or Other	Description	Working Group Position for Subsection (h) Entities[2]	CompSouth	NCTIA	Public Staff
8	G.S. 62-110(f1) and P-100, Sub 133	Arbitrations and Interconnection Agreements	Not affected by HB 1180.	Agree.	Agree.	Agree.
9	G.S. 62-110(f1)	Universal Service	Not affected by HB 1180.	Agree.	Agree.	Agree.
10	G.S. 62-110(f4), (f5), (f6) and P-100, Sub 152b	Carrier of Last Resort Obligations and COLR Relief Report	Not affected by HB 1180.	Agree.	Agree.	Agree.
11	G.S. 62-111	Transfers of Franchises; Mergers, Consolidations and Combinations of Public Utilities	(i) Not applicable to retail services offered by Subsection (h) entities. (ii) Exemptions granted under Subsection (g) do not automatically apply to Subsection (h) entities. (iii) Applicable to non-retail services provided by Subsection (h) entities.	Agree.	Agree with (i) and (ii). Disagree with (iii). Does not need to apply to Subsection (h) companies for non-retail since excluded for price regulation companies	Subsection (h) entities should be required to adhere to the requirements adopted by the Commission in NCUC Rule R17-8.
12	G.S. 62-118	Abandonment or Reduction of Service	(i) Not applicable to retail services other than stand-alone basic residential service of Subsection (h) entities. (ii) Applicable to non-retail services of Subsection (h) entities.	Agree.	Agree.	Agree.
13	G.S. 62-130	Commission to Make Rates for Public Utilities; Customer Refunds	(i) Not applicable to retail services offered by Subsection (h) entities, except G.S. 62-130(e) applies to residential standalone service. (ii) Exemptions granted under Subsection (g) do not automatically apply to Subsection (h) entities. (iii) Applicability to non-retail services provided by Subsection (h) entities will be addressed in future comments on non-retail regulation of Subsection (h) entities.	Agree.	Agree .	Agree.

Issue	NCUC Rule/Statute or Other	Description	Working Group Position for Subsection (h) Entities[2]	CompSouth	NCTIA	Public Staff
14	G.S. 62-131	Rates Must be Just and Reasonable; Service Efficient	(i) Not applicable to retail services offered by Subsection (h) entities. (ii) Exemptions granted under Subsection (g) do not automatically apply to Subsection (h) entities. (iii) Applicability to non-retail services provided by Subsection (h) entities will be addressed in future comments on non-retail regulation of Subsection (h) entities.	Agree.	Agree.	Agree.
15	G.S. 62-132	Rates Established under this Chapter Deemed Just and Reasonable; Remedy for Collection of Unjust or Unreasonable Rates	(i) Not applicable to retail services offered by Subsection (h) entities except for its application to standalone residential service. (ii) Exemptions granted under Subsection (g) do not automatically apply to Subsection (h) entities. (iii) Applicability to non-retail services provided by Subsection (h) entities will be addressed in future comments on non-retail regulation of Subsection (h) entities.	Agree.	Disagree with (i) and agree with (ii) and (iii). G.S. 62-132 addresses unjust and unreasonable rates and; therefore, expands the authority of the Commission beyond the intent of HB 1180. 62-133.5(h)(2) provides full authority to the Commission to ensure compliance of this requirement.	Agree.
16	G.S. 62-133	Establishment of Rates	(i) Not applicable to retail services offered by Subsection (h) entities. (ii) Exemptions granted under Subsection (g) do not automatically apply to Subsection (h) entities. (iii) Applicability to non-retail services provided by Subsection (h) entities will be addressed in future comments on non-retail regulation of Subsection (h) entities.	Agree.	Agree.	Agree.
17	G.S.-133.5(f)	Retail Promotions	Not applicable to retail services offered by Subsection (h) entities.	Agree; however, the Commission retains jurisdiction over carrier competition issues and may wish to consider whether it is necessary to impose a notice requirement to ensure that CLPs have notice of availability of retail service and promotional offerings.	Agree.	Agree.

Issue	NCUC Rule/Statute or Other	Description	Working Group Position for Subsection (h) Entities[2]	CompSouth	NCTIA	Public Staff
18	G.S. 62-133.5(g)	Price Regulation Exemptions	Exemptions granted under Subsection (g) do not automatically apply to Subsection (h) entities.	Agree.	Agree.	Agree.
19	G.S. 62-134	Change of Rates; Notice; Suspension and Investigation	(i) Not applicable to retail services offered by Subsection (h) entities. (ii) Exemptions granted under Subsection (g) do not automatically apply to Subsection (h) entities. (iii) Applicability to non-retail services provided by Subsection (h) entities will be addressed in future comments on non-retail regulation of Subsection (h) entities.	Agree.	Agree.	Agree.
20	G.S. 62-135	Temporary Rates Under Bond	(i) Not applicable to retail services offered by Subsection (h) entities. (ii) Exemptions granted under Subsection (g) do not automatically apply to Subsection (h) entities. (iii) Applicability to non-retail services provided by Subsection (h) entities will be addressed in future comments on non-retail regulation of Subsection (h) entities.	Agree.	Agree.	Agree.
21	G.S. 62-136	Investigation of Existing Rates, Changing Unreasonable Rates, etc.	(i) Not applicable to retail services offered by Subsection (h) entities. (ii) Exemptions granted under Subsection (g) do not automatically apply to Subsection (h) entities. (iii) Applicability to non-retail services provided by Subsection (h) entities will be addressed in future comments on non-retail regulation of Subsection (h) entities.	Agree.	Agree.	Agree.
22	G.S. 62-137	Scope of Rate Case	(i) Not applicable to retail services offered by Subsection (h) entities. (ii) Exemptions granted under Subsection (g) do not automatically apply to Subsection (h) entities. (iii) Applicability to non-retail services provided by Subsection (h) entities will be addressed in future comments on non-retail regulation of Subsection (h) entities.	Agree.	Agree.	Agree.

Issue	NCUC Rule/Statute or Other	Description	Working Group Position for Subsection (h) Entities[1]	CompSouth	NCTIA	Public Staff
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 (h) entities. (ii) Applicable to non-retail services of Subsection (h) entities. (iii) 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.	Agree.	Agree.	Agree.
24	G.S. 62-139	Rates Varying from Schedule Prohibited; Refunding Overcharges; Penalty	(i) Not applicable to retail services offered by Subsection (h) entities. (ii) Exemptions granted under Subsection (g) do not automatically apply to Subsection (h) entities. (iii) Applicability to non-retail services provided by Subsection (h) entities will be addressed in future comments on non-retail regulation of Subsection (h) entities.	Agree.	Agree.	Agree.
25	G.S. 62-140	Nondiscrimination	Not applicable to retail services offered by Subsection (h) entities.	Agree.	Agree.	Agree.
26	G.S. 62-142	Contracts as to Rates	(i) Not applicable to retail services offered by Subsection (h) entities. (ii) Exemptions granted under Subsection (g) do not automatically apply to Subsection (h) entities. (iii) Subsection (h) entities should be exempted.	Agree with (i) and (ii).[3]	Agree.	Agree.
27	G.S. 62-148	Rates on Leased or Controlled Utility	Not applicable to retail services offered by Subsection (h) entities.	Agree.	Agree.	Agree.
28	G.S. 62-153	Contracts of Public Utilities	(i) Not applicable to retail services offered by Subsection (h) entities. (ii) Exemptions granted under Subsection (g) do not automatically apply to Subsection (h) entities. (iii) Subsection (h) entities should be exempted.	Agree with (i) and (ii).[3]	Agree.	Agree.
29	G.S. 62-300, 62-302, R15-1 and M-100, Sub 118	Fees and Charges including Regulatory Fees	Will apply to Subsection (h) entities.	Agree.	Agree.	Agree.

Issue	NCUC Rule/Statute or Other	Description	Working Group Position for Subsection (h) Entities[1]	CompSouth	NCTIA	Public Staff
30	G.S. 62-310	Violations	(i) Not applicable to retail services other than stand-alone basic residential service of Subsection (h) entities. (ii) Applicable to non-retail services of Subsection (h) entities.	Agree.	Agree.	Agree.
31	R1-15	Investigation and Suspension Proceedings	(i) Not applicable to retail services of Subsection (h) entities. (ii) Applicability to non-retail services provided by Subsection (h) entities will be addressed in future comments on non-retail regulation of Subsection (h) entities.	Agree, except that R1-15 should be construed to apply to stand-alone basic residential service of electing entities.	Agree	Agree.
32	R1-17	Filing of Increased Rates	(i) Not applicable to retail services. (ii) Applicability to non-retail services provided by Subsection (h) entities will be addressed in future comments on non-retail regulation of Subsection (h) entities	Agree.	Agree.	Agree.
33	R1-18	Reparations and Undercharges	(i) Not applicable to retail services other than stand-alone basic residential service of Subsection (h) entities. (ii) Applicability to non-retail services provided by Subsection (h) entities will be addressed in future comments on non-retail regulation of Subsection (h) entities.	Agree.	Agree.	Agree.
34	R1-32, R9-9	Form M report & other financials	(i) Public ILECs should provide link to Securities and Exchange Commission filings on annual basis. (ii) Audited financials should be filed on annual basis by non-public ILEC filings (Citizens, Ellerbe, Pineville, and Randolph). (iii) Public CLPs with COLR responsibilities should provide link to Securities and Exchange Commission filings on annual basis . (iv) Non-public CLPs with COLR responsibilities should submit audited financials on annual basis.	Agree.	Agree.	Agree.
35	R9-1	Safety Rules and Regulations	Not affected by HB 1180.	Agree.	Agree.	Agree.

Issue	NCUC Rule/Statute or Other	Description	Working Group Position for Subsection (h) Entities[2]	CompSouth	NCTIA	Public Staff
36	R9-2	Uniform System of Accounts (USOA)	Subsection (h) entities should be exempted.	CompSouth does not take a position on continued need for this requirement at this time.	Agree.	Agree.
37	R9-3	Annual Filing of Construction Plans and Objectives	(i) Subsection (h) entities should be exempted. (ii) Rule should be eliminated for subsection (h) and all other LECs	CompSouth does not take a position on continued need for this requirement at this time.	Agree.	Agree.
38	R9-4	Telephone and Telegraph Tariffs and Maps - Retail	(i) Not applicable to retail services offered by Subsection (h) entities. (ii) Applicable to currently tariffed non-retail services of Subsection (h) entities. (iii) 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. (iv) ILEC maps should continue to be filed.	Agree.	Agree.	Agree.
39	R9-5 and P-100, Sub 142, Sub 150 and Sub 153	N11 Services and Tariffs	Only rules and orders relating to 711 service will be applicable to Subsection (h) entities.	Agree.	Agree.	Agree.
40	R9-6, P-100, Sub 133f	Lifeline/Linkup Service, Reports and Tariffs, Lifeline Toll Restriction	Not affected by HB 1180.	Agree.	Agree.	Agree.
41	R9-7	Extended Area Service	Not applicable to Subsection (h) entities.	Agree.	Agree.	Agree.
42	R9-8 and P-100, Sub 99	Service Quality and Service Quality Results Reports	Not applicable to Subsection (h) entities.	Agree.[4] Also, these same rules should be relieved for all CLPs. It makes no sense that LECs are excused on grounds of competition but their competitors are not.	Agree.	Agree.

Issue	NCUC Rule/Statute or Other	Description	Working Group Position for Subsection (h) Entities[3]	CompSouth	NCTIA	Public Staff
43	R12-1	Deposit Policy - Declaration of Public Policy	Not applicable to Subsection (h) entities.	Agree; however, these same rules should be relieved for all CLPs. It makes no sense that LECs are excused on grounds of competition but their competitors are not.	Agree.	Agree.
44	R12-2	Establishment of Credit for Consumers	Not applicable to Subsection (h) entities.	Agree; however, these same rules should be relieved for all CLPs. It makes no sense that LECs are excused on grounds of competition but their competitors are not.	Agree.	Agree.
45	R12-3	Reestablishment of Service for Consumers	Not applicable to Subsection (h) entities.	Agree; however, these same rules should be relieved for all CLPs. It makes no sense that LECs are excused on grounds of competition but their competitors are not.	Agree.	Agree.
46	R12-4	Deposit and Interest on Deposits	Not applicable to Subsection (h) entities.	Agree; however, these same rules should be relieved for all CLPs. It makes no sense that LECs are excused on grounds of competition but their competitors are not.	Agree.	Agree.
47	R12-5	Deposit Refund Policy	Not applicable to Subsection (h) entities.	Agree; however, these same rules should be relieved for all CLPs. It makes no sense that LECs are excused on grounds of competition but their competitors are not.	Agree.	Agree.
48	R12-6	Deposit Records	Not applicable to Subsection (h) entities.	Agree; however, these same rules should be relieved for all CLPs. It makes no sense that LECs are excused on grounds of competition but their competitors are not.	Agree.	Agree.

Issue	NCUC Rule/Statute or Other	Description	Working Group Position for Subsection (h) Entities[2]	CompSouth	NCTIA	Public Staff
49	R12-7	Appeal by Applicant or Customer in Connection with Billing Decisions	Not applicable to Subsection (h) entities.	Agree; however, these same rules should be relieved for all CLPs. It makes no sense that LECs are excused on grounds of competition but their competitors are not.	Agree.	Agree.
50	R12-8	Discontinuance of Service for Nonpayment	Not applicable to Subsection (h) entities.	Agree; however, these same rules should be relieved for all CLPs. It makes no sense that LECs are excused on grounds of competition but their competitors are not.	Agree.	Agree.
51	R12-9	Uniform Billing Procedure	Not applicable to Subsection (h) entities.	Agree; however, these same rules should be relieved for all CLPs. It makes no sense that LECs are excused on grounds of competition but their competitors are not.	Agree.	Agree.
52	R12-12	Definitions	Not applicable to Subsection (h) entities.	Agree; however, these same rules should be relieved for all CLPs. It makes no sense that LECs are excused on grounds of competition but their competitors are not.	Agree.	Agree.
53	R12-14	Advertising by Telephone Companies	Not applicable to Subsection (h) entities.	Agree; however, these same rules should be relieved for all CLPs. It makes no sense that LECs are excused on grounds of competition but their competitors are not.	Agree.	Agree.
54	R12-16	Bill inserts - Costs shall not be passed to Customers	Not applicable to Subsection (h) entities.	Agree; however, these same rules should be relieved for all CLPs. It makes no sense that LECs are excused on grounds of competition but their competitors are not.	Agree.	Agree.

Issue	NCUC Rule/Statute or Other	Description	Working Group Position for Subsection (h) Entities[3]	CompSouth	NCTIA	Public Staff
55	R12-17	Disconnection, Denial and Billing of Telephone Service	Not applicable to Subsection (h) entities.	Agree; however, these same rules should be relieved for all CLPs. It makes no sense that LECs are excused on grounds of competition but their competitors are not.	Agree.	Agree.
56	Rule 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 (h) entities. (ii) Rule R17-2(f)(4 and 8) are not affected by HB 1180. (iii) Rule R17-2(f)(2) requirement for CLPs to provide directories should not be applicable in areas where ILEC is Subsection (h) company and no longer has requirement to publish directories. (iv) Commission should amend CLP application form so that, if desired, a CLP can file an application for certification and Subsection (h) election at the same time.	Agree.	Agree.	Agree.
57	Rule R17-2(g)	Requirements and Limitations Regarding Certification of Competing Local Providers (Compliance with service quality and customer deposit rules)	Not applicable to Subsection (h) entities.	Agree; however, these same rules should be relieved for all CLPs. It makes no sense that LECs are excused on grounds of competition but their competitors are not.	Agree.	Agree.
58	Rule R17-2(i)	Requirements and Limitations Regarding Certification of Competing Local Providers (GAAP compliance)	Subsection (h) entities should be exempted	Agree	Agree.	Agree.
59	Rule R17-2(j)	Requirements and Limitations Regarding Certification of Competing Local Providers (Financial reports)	Not applicable to retail services offered by Subsection (h) entities.	Agree.	Agree.	Agree.

Issue	NCUC Rule/Statute or Other	Description	Working Group Position for Subsection (h) Entities[2]	CompSouth	NCTIA	Public Staff
60	Rule R17-2(k)	Requirements and Limitations Regarding Certification of Competing Local Providers (Access line reports)	(i) Some form of access line information is necessary for certain continuing Commission functions (i.e., TRS fund). (ii) A simpler format and longer filing frequency is acceptable. The parties anticipate filing a separate proposal to modify this requirement.	Agree.	Agree.	Agree.
61	Rule R17-2(l)	Requirements and Limitations Regarding Certification of Competing Local Providers (TRS and G.S. 62-157)	Not affected by HB 1180.	Agree.	Agree.	Agree.
62	Rule R17-2(m)	Requirements and Limitations Regarding Certification of Competing Local Providers (Adherence to Chapter 62A)	Not affected by HB 1180.	Agree.	Agree.	Agree.
63	Rule R17-2(n)	Requirements and Limitations Regarding Certification of Competing Local Providers (Compliance with Rule R12-17)	Not applicable to Subsection (h) entities.	Agree; however, these same rules should be relieved for all CLPs. It makes no sense that LECs are excused on grounds of competition but their competitors are not.	Agree.	Agree.
64	Rule R17-2(p)	Requirements and Limitations Regarding Certification of Competing Local Providers (Billing of third party services)	Not applicable to Subsection (h) entities.	Agree; however, these same rules should be relieved for all CLPs. It makes no sense that LECs are excused on grounds of competition but their competitors are not.	Agree.	Agree.
65	Rule R17-2(q)	Requirements and Limitations Regarding Certification of Competing Local Providers (Rate increase notice)	Not applicable to Subsection (h) entities.	Agree; however, these same rules should be relieved for all CLPs. It makes no sense that LECs are excused on grounds of competition but their competitors are not.	Agree.	Agree.

Issue	NCUC Rule/Statute or Other	Description	Working Group Position for Subsection (h) Entities[2]	CompSouth	NCTIA	Public Staff
66	Rule R17-2(r)	Requirements and Limitations Regarding Certification of Competing Local Providers (Billings for pay-per-call services)	Not applicable to Subsection (h) entities.	Agree; however, these same rules should be relieved for all CLPs. It makes no sense that LECs are excused on grounds of competition but their competitors are not.	Agree.	Agree.
67	Rule R17-2(s)	Requirements and Limitations Regarding Certification of Competing Local Providers (Timing of calls)	Not applicable to Subsection (h) entities.	Agree; however, these same rules should be relieved for all CLPs. It makes no sense that LECs are excused on grounds of competition but their competitors are not.	Agree.	Agree.
68	Rule R17-2(t)	Requirements and Limitations Regarding Certification of Competing Local Providers (Compliance with Rule R13)	Not affected by HB 1180.	Agree.	Agree.	Agree.
69	Rule R17-2(u)	Requirements and Limitations Regarding Certification of Competing Local Providers (Regulatory fee)	Not affected by HB 1180.	Agree.	Agree.	Agree.
70	Rule R17-2(v)	Requirements and Limitations Regarding Certification of Competing Local Providers (Service provided in unlawful manner)	Not affected by HB 1180.	Agree.	Agree.	Agree.
71	Rule R17-2(w)	Requirements and Limitations Regarding Certification of Competing Local Providers (Penalty for disconnection)	Not applicable to Subsection (h) entities.	Agree; however, these same rules should be relieved for all CLPs. It makes no sense that LECs are excused on grounds of competition but their competitors are not.	Agree.	Agree.

Issue	NCUC Rule/Statute or Other	Description	Working Group Position for Subsection (h) Entities[3]	CompSouth	NCTIA	Public Staff
72	Rule R17-6(a)	Prepaid Local Exchange Service (Exemptions from Rule R17-2(f))	The exemptions from Rule R17-2(f) for prepaid providers set forth in Rule R17-6(a) remain in effect for Subsection (h) entities. The second sentence of Rule R17-6(a) is overridden for an electing CLP to the extent that electing CLPs are excused from the obligations of Rule R17-2(f).	Agree.	Agree.	Agree.
73	Rule R17-6(b)	Prepaid Local Exchange Service (Terms and conditions for service)	Not applicable to Subsection (h) entities except for Rule R17-6(b)(1)(iv).	Agree.	Agree.	Agree.
74	Rule R17-6(c)	Prepaid Local Exchange Service (Customer service agreement)	Not applicable to Subsection (h) entities.	Agree.	Agree.	Agree.
75	Rule R17-7	Dialing Parity	Not affected by HB 1180.	Agree.	Agree.	Agree.
76	*R20-1(a)(b)(c)(e)*	Slamming - Marketing Activity Regulations other than Federal Requirements	Rule should be revised to reflect FCC slamming requirements.	Agree.	Agree.	Agree
77	*R20-1(d)*	Cramming	Not applicable to Subsection (h) entities.	Agree	Agree.	Agree.
78	Rule R20-2	Fair competition among local telecommunications service providers.	Not affected by HB 1180.	Agree.	Agree.	Agree.
79	Rule R21-1	Application of rule	(i) Not applicable to retail services other than stand-alone basic residential service of Subsection (h) entities. (ii) Applicable to non-retail services of Subsection (h) entities.	Agree.	Agree.	Agree.
80	Rule R21-2	Discontinuance or Reduction of Telecommunica- tions Service by LECs and CLPs	(i) Not applicable to retail services other than stand-alone basic residential service of Subsection (h) entities. (ii) Applicable to non-retail services of Subsection (h) entities.	Agree.	Agree.	Agree.

Issue	NCUC Rule/Statute or Other	Description	Working Group Position for Subsection (h) Entities[2]	CompSouth	NCTIA	Public Staff
81	Rule R21-3	Bankruptcy	(i) Not applicable to retail services other than stand-alone basic residential service of Subsection (h) entities. (ii) Applicable to non-retail services of Subsection (h) entities.	Agree.	Agree.	Agree.
82	R21-4	Discontinuance or Reduction of Telecommunications Service (by CLP or LEC)	(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.	Agree.	Agree.	Agree.
83	HB1180	Annual Report of Company Operations Reviewed by the Joint Legislative Utility Review Committee - Report Due January 30th of Each Year	Subsection (h) entities are required to file a report with the Legislature.	Agree.	Agree.	Agree.
84	HB1180	Monitoring Compliance with GDPPI for Stand-Alone Basic Residential Lines	(i) Commission has authority to monitor and enforce compliance with allowed increases for stand-alone basic residential service lines (ii) Working group recommends that on anniversary date of Subsection (h) election or when rates change, rates should be filed in Subsection (h) docket.	Agree.	Agree.	Agree.
85	HB1180	Public Staff Shall Keep Record of all Complaints Received and Complaints can be Referred to the Commission.	(i) Public Staff is to maintain record of all complaints and status of resolution. (ii) Inform customer that complaints can be referred to Commission.	Agree.	Agree.	Agree.

Issue	NCUC Rule/Statute or Other	Description	Working Group Position for Subsection (h) Entities[3]	CompSouth	NCTIA	Public Staff
86	P-100, Subs 65 and 72	Switched Access and intraLATA Toll Originating Responsibility Plan (ITORP) and Associated Tariffs and Intercarrier Compensation	Not affected by HB 1180.	Agree.	Agree.	Agree.
87	Price Reg Dockets	Price Reg Annual Filing for Regulated Services	(i) Not applicable to retail services offered by Subsection (h) entities. (ii) Applicability to non-retail services provided by Subsection (h) entities will be addressed in future comments on non-retail regulation of Subsection (h) entities.	Agree.	Agree.	Agree.
88	Standing Data Request (origin uncertain)	Central Office Equipment Report	(i) Filing requirements should be eliminated for all subsection (h) entities and all other LECs (ii) Information should remain available in the event of Commission or Staff request (i.e., for verification of UNE Zone status under FCC UNE rules).	Agree.	Agree.	Agree.
89	Tariff Requirement	Directories - White Pages	Not applicable to Subsection (h) entities. Electing entities are not required to publish white pages directories.	Agree.	Agree.	Agree.
90	Price Reg Dockets	Price Reg Report - Monthly (service measures, complaints, customer notice, etc.)	Price regulation plans are no longer in effect for Subsection (h) entities.	CompSouth agrees that price regulation reports and other retail regulations contained in price plans are superseded by a Subsection (h) election. It is an open question whether other, non-retail requirements set forth in price plans continue to survive. Price plans could potentially provide a vehicle for regulation of wholesale activities.	Agree.	Agree.
91	P-55, Sub 1013	Price Reg Service List Report - AT&T Only	Price regulation plans are no longer in effect for Subsection (h) entities.	Agree.	Agree.	Agree.

Issue	NCUC Rule/Statute or Other	Description	Working Group Position for Subsection (h) Entities[2]	CompSouth	NCTIA	Public Staff
92	Commission Memo	Station Development Report	(i) Some form of access line information from Subsection (h) entities is necessary for certain continuing Commission functions (i.e.; TRS fund). The parties anticipate filing a separate proposal to modify this requirement. (ii) A report by Subsection (h) entities on total access lines as of June 30 and December 31 is acceptable.	Agree.	Agree.	Agree.

[1] HB 1180 takes away the Commission's broad authority over retail services for electing entities. Where the phrase "not applicable to retail services offered by Subsection (h) entities" is used with reference to a specific statute, the Working Group intends this reference to mean that the Commission does not have authority under the referenced statute with respect to retail services offered by electing entities. The Working Group intends that exemptions specified herein for Subsection (h) electing LECs be extended to Subsection (i) electing CLPs, to the extent that such regulations otherwise apply to CLPs.

[2] For purposes of this Matrix, the Working Group is using the phrase "Subsection (h) Entities" to include CLPs who opt into the Subsection (h) regulatory plan as permitted under Subsection (i). As reflected in its comments filed in this proceeding, CompSouth notes its position that electing CLPs do not become "Subsection (h) entities" by exercising the rights granted under Subsection (i) but rather they remain CLPs that receive the benefits of deregulation afforded Subsection (h) electing entities.

[3] CompSouth recognizes that HB 1180 is intended as a deregulatory statute. CompSouth also recognizes that ILECs operating under price plans benefit from certain statutory exemptions specified in G.S. 62-133.5(g) which are not carried forward for Subsection (h) electing entities. That said, it is not necessary for the Commission to broadly exempt electing entities from Subsection (g) statutes at this time. First, the Commission retains authority over wholesale services and the parties have not yet fully examined the potential application of the Subsection (g) statutes to the Commission's retained authority. Second, several of the Subsection (g) statutes are general grants of authority to the Commission – not regulatory requirements imposed on regulated entities – and it is not necessary or, perhaps, appropriate for the Commission to exempt electing entities from such statutes in the context of this proceeding. Third, there is an open question whether the Commission has the authority to exempt electing entities from the operation of these statutes given that the legislature did not itself grant such exemption.

[4] CompSouth agrees that regulation of the manner in which retail service is provided are among the areas which the Commission is prohibited from regulating for entities that opt into Subsection (h) deregulation and, therefore, by extension, Rule R9-8 would not apply to such entities' retail services. However, CompSouth would note that service quality standards for wholesale service would be unaffected by HB 1180. In the event a service quality standard for a LEC's wholesale service is measured by reference to a retail analog (whether by rule, order or interconnection agreement), this retail analog would remain in place for Subsection (h) electing entities. In a similar proceeding, the Florida Commission has adopted the following clarifying language on this point: "None of the rule amendments or repeals are intended to impact in any way wholesale service or the SEEM (Self-Effectuating Enforcement Mechanism) plan, the SEEM metrics or payments, or the type of data that must be collected and analyzed for purposes of the SEEM plan." *See Notice of Rule Making*, Order No. PSC-09-0054-NOR-TP, Docket Nos. 080159-TP, 080641-TP (Florida Pub. Serv. Comm'n Jan. 23, 2009), at page 1. Similar clarification should be made in this proceeding.